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COMMISSION

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Introduction

This report represents the Renewables Committee's (Committee) proposed recommendations to the California Energy Commission on Phase 2 issues in the Renewable Portfolio Standard (RPS) proceeding.

The Energy Commission established the RPS proceeding on March 5, 2003 in response to statutory requirements of Senate Bill 1078 (SB 1078, Sher, Statutes of 2002, Chapter 516) and Senate Bill 1038 (SB 1038, Sher, Statutes of 2002, Chapter 515), both signed by Governor Davis on September 12, 2002. These laws took effect January 1, 2003 and are codified in Public Utilities Code (PUC) sections 399.11 through 399.15, and sections 381, 383.5, and 445, respectively.

This report is divided into two sections. The introductory section summarizes the report scope and development process, and discusses the legislative requirements of SB 1078 and SB 1038 for each of the Phase 2 issue areas. The report then presents the Committee's proposed decisions, as well as the rationale for those decisions, for each issue area. Appendices include a list of participants in the RPS proceeding, excerpts of relevant statutory language from SB 1078 and SB 1038, a glossary of terms, and a list of acronyms used in the report.

Report Scope

This report presents the Committee's proposed decisions on Phase 2 implementation issues:

- distributing supplemental energy payments (SEPs),
- certifying renewable electricity generation facilities, and
- developing the accounting system for the RPS.

The recommendations presented in this report provide policy direction on a variety of key issues. The Committee recognizes, however, that additional implementation details will need to be identified and resolved during the development of guidelines for certification of renewable resources and payment of SEPs.

This report also addresses the interaction between the Renewable Energy Program (REP) established by Senate Bill 90 (SB 90, Sher, Statutes of 1997, Chapter 905) and the RPS as it relates to new renewable facilities. Under SB 90, the Energy Commission provided conditional funding awards to new renewable facilities in the form of production incentives paid on a cents per kilowatt hour basis once facilities begin operation. The Energy Commission pays these production incentives for the first five years of project operation.

Of the 71 active new renewable projects that received awards under SB 90, 40 are operating and receiving payments. The remaining 31 projects will receive payments once they are on-line. Because SB 1038 revises the REP structure and links payments to new renewable electricity generating facilities to the RPS, this report addresses how projects participating in the SB 90 program may also participate in the RPS with respect to SEP eligibility.

The *Renewable Portfolio Standard: Decision on Phase 1 Implementation Issues,* adopted by the Energy Commission on June 11, 2003, also identified issues needing further development during Phase 2. These issues include developing certification procedures in collaboration with other agencies for small hydro, biomass, and municipal solid waste conversion technologies, as well as developing criteria to be used to determine incremental geothermal resources. Although not addressed in this report, these activities are ongoing and will be part of the subsequent guideline development process.

Based on input at the May 12 workshop, the Committee has deferred consideration of whether the Energy Commission should provide preference to projects that provide tangible demonstrable benefits to communities with a plurality of minority or low-income populations. The Committee has also deferred the discussion of caps on SEPs. Parties requested, and the Committee agreed, that these topics be addressed after the California Public Utilities Commission (CPUC) adopted its decision on RPS implementation. The CPUC adopted Decision 03-06-071 on June 19, 2003, which did not provide the Committee with sufficient time to review the CPUC decision and address the deferred items in this draft report. However, the Committee will address these issues in the final version of this report expected in early September 2003.

This report does not address issues regarding distributed generation or how the RPS will apply to Electric Service Providers (ESPs) or Community Choice Aggregators (CCAs); however, in drafting its decisions, the Committee made every effort to recognize the eventual and equal participation of these parties. Consistent with the Workplan, the Energy Commission will address these issues during Phase 3 of the RPS proceeding.

Other Phase 3 issues not addressed in this report include developing a final process for accounting and verification and working with the CPUC to address other issues such as resource diversity, competitive sufficiency, and eligibility of distributed generation technologies.

Report Development Process

In SB 1078, the Energy Commission and the CPUC both have clearly defined roles in implementing the RPS and are also directed to work collaboratively across a range of implementation issues. In October 2002, the staffs from the two agencies began working together to develop a joint RPS Collaboration Workplan (Workplan).

On March 5, 2003, the Energy Commission issued Order No. 03-0305-04 authorizing the Committee to work with the CPUC to implement the RPS program. The Committee then issued a March 14, 2003 order that initiated a proceeding to address issues identified in the Workplan. The order established administrative procedures for participating in the proceeding and included a copy of the Workplan, along with a proposed schedule of work products and decisions.

The RPS proceeding is divided into three broad phases. Phase 1 issues are those that can be resolved by mid-2003, Phase 2 issues will be addressed by mid- to late 2003, and Phase 3 issues are expected to be resolved by the end of 2003. Phase 1 issues were addressed in the *Renewable Portfolio Standard: Decision on Phase 1 Implementation Issues* (publication number 500-03-023F), which was adopted by the Energy Commission at its June 11, 2003 Business Meeting.

On May 12 and 13, 2003, the Energy Commission staff held a two-day workshop to solicit input from stakeholders on Phase 2 issues. The workshop topics included distributing supplemental energy payments, certifying renewable electricity generation facilities, and developing an accounting system for the RPS. Participants included trade organizations, electricity generators, environmental groups, consumer protection organizations, utilities, state and county government agencies, and marketers. Participants were asked to respond orally to a list of questions and submit written comments by May 19, 2003. A complete list of participants is included as Appendix A.

The Committee developed this report based on oral and written comments from the May 12 and 13, 2003 workshops, and on the expertise of collaborative staff and technical support contractors. The Committee would like to acknowledge the active and thoughtful participation of the parties in this proceeding and their contribution to developing the proposed decisions contained in this report.

The Committee will hold a hearing on July 14, 2003 to receive input on the proposed decisions contained in this report, and will develop a final report based on that input to be submitted to the Energy Commission for possible adoption at the September 17, 2003 Business Meeting.

Once the Energy Commission approves the Committee's proposed Phase 2 decisions, the Committee will begin the process of developing guidelines to implement the decisions. PUC section 385.5(h)(1) gives the Energy Commission the authority to develop guidelines to implement portions of the RPS dealing with funding under SB 1038. These guidelines are exempt from the formal rulemaking requirements of the Administrative Procedures Act. As a result, guidelines on SEPs and certification of renewable resources can be developed within months and can be modified as necessary to adapt to developments in the market.

Although PUC section 399.13(b) requires the Energy Commission to "design and implement an accounting system to verify compliance with the renewables portfolio standard by retail sellers," it does not give the Energy Commission the authority to

implement such a system through guidelines. Because the system will not govern funding under SB 1038, regulations for the long-term tracking and verification system must be developed through a formal rulemaking process. In addition, the system's development and implementation need to be coordinated with the Energy Commission's existing regulations for the Power Source Disclosure Program (Title 20, California Code of Regulations, sections 1390, et seq).

The Committee recognizes that the CPUC will continue to develop rules for implementing the RPS, and that both the Energy Commission and the CPUC must be prepared to re-evaluate and modify these rules as necessary in response to new information as well as lessons learned from program implementation. Successful implementation of the RPS will require continual monitoring to ensure that the program is meeting the statutory goals in SB 1078, while maintaining flexibility in implementing the program will allow the Energy Commission to make any necessary mid-course corrections.

Statutory Requirements

SB 1078 establishes an RPS program that requires retail sellers of electricity, such as investor-owned utilities (IOUs), to increase the renewable content of their electricity deliveries by at least one percent per year over a baseline level to be determined by the CPUC. Retail sellers must meet a target of 20 percent renewable content in their electricity portfolio by December 31, 2017.

Retail sellers may meet the 20 percent renewable content requirement under SB 1078 with both baseline renewable energy and the required additional procurement of renewable energy resources. The quantity of eligible renewable energy resources procured in 2001 determines a baseline of renewable procurement for retail sellers. Above this baseline, retail sellers face a required additional procurement of renewable energy resources.

The CPUC is responsible for setting the baseline and required additional procurement; therefore, any discussion of baseline and required additional procurement in this report is provided only as background and should not be considered as a determination by the Energy Commission.

The Energy Commission's specific responsibilities under SB 1078 include the following: certifying eligible renewable energy resources; designing and implementing an accounting system to verify compliance with the renewables portfolio standard by retail sellers; and allocating and awarding SEPs to cover above-market costs of renewable energy.

SB 1038 continues implementation authority for the Energy Commission's REP, but also makes changes to the REP's structure and funding allocation. One of the structural changes is that payments made to new renewable electricity generation facilities are

now linked to the RPS, with the goal of increasing the amount of renewable generation in California.

Statutory requirements for the Phase 2 activities — distributing supplemental energy payments, certifying electricity generation facilities, and developing an RPS accounting system — are summarized below. Pertinent sections of the statutory language are provided in Appendix B.

1. Distributing Supplemental Energy Payments

SB 1078 directs the Energy Commission to "allocate and award supplemental energy payments" to "eligible renewable energy resources to cover above-market costs of renewable energy." The CPUC, in consultation with the Energy Commission, will determine what constitutes these above-market costs.

SB 1038 describes how public goods charge (PGC) funding is allocated in the Energy Commission's Renewable Energy Program. SB 1038 allocates 51.5 percent of the $135 million in PGC funds collected annually to the New Renewable Facilities Program (NRFP). The Energy Commission recently reallocated an additional 4.5 percent of the funds from the Customer Credit Account to the NRFP.

The NRFP will award SEPs to cover the above-market costs of renewable resources that are selected by retail sellers to fulfill their RPS obligations to "foster the development of new in-state renewable electricity generation technology facilities, and to secure for the state the environmental, economic, and reliability benefits that continued operation of those facilities will provide."

SB 1038 specifies that repowered existing facilities are also eligible for SEPs "if the capital investment to repower the existing facility equals at least 80 percent of the value of the repowered facility."

SB 1038 establishes specific criteria for the Energy Commission to use when awarding SEPs. The Energy Commission:

- may establish payment caps,
- shall make payments for 10 years, or the length of the contract with the electrical corporation if it is of a lesser duration,
- shall reduce or terminate SEPs for projects that either fail to commence or maintain operations in accordance with contractual obligations or that fail to meet eligibility requirements,
- shall manage the funds in an equitable manner such that retail sellers may meet their RPS obligations,

- may require an applicant competing for funding to post a forfeitable bid bond or other financial guaranty of the applicant's good faith intent to move forward with the project expeditiously, and

- may provide preference to projects that provide tangible, demonstrable benefits to communities with a plurality of minority or low income populations.

SB 1038 further states that facilities may NOT receive SEPs if the electricity produced is:

- sold under an existing long term contract with an existing in-state electrical corporation if the contract includes fixed energy or capacity payments,

- used on-site or sold in a manner that is excluded from competitive transition charge payments, or

- produced by a facility owned by an electrical corporation or publicly owned utility.

SB 1078 and SB 1038 also describe what renewable energy resources qualify for the RPS, and for SEP. The Committee's recommendations for implementing these provisions are discussed in the *Renewable Portfolio Standard: Renewables Committee Decision on Phase 1 Implementation Issues,* May 2003, which the Energy Commission formally adopted on June 11, 2003.

SB 1078 defines an "eligible renewable energy resource" as a facility that meets the definition of "in-state renewable electricity generation technology" as provided in SB 1038. Such a facility must meet the following criteria:

- use biomass, solar thermal, photovoltaic, wind, geothermal, fuel cells using renewable fuels, small hydroelectric generation of 30 megawatts or less, digester gas, municipal solid waste conversion using a non-combustion thermal process, landfill gas, ocean wave, ocean thermal, tidal current, and any additions or enhancements to the facility using that technology, and

- be located in California or near the border with the first point of connection to the Western Electricity Coordinating Council transmission system located within California. SB 1038 states that the Energy Commission may find a facility located out of state eligible for SEPs if it meets specific requirements.

SB 1038 and SB 1078 also impose additional restrictions on the eligibility for SEPs of small hydro, biomass, solid waste conversion, municipal solid waste (MSW) combustion facilities, and geothermal. New small hydro, biomass, and MSW facilities are eligible for SEPs if they meet specific criteria. New small hydro facilities qualify for SEPs if they do not require new or increased appropriation or diversion of water. New biomass facilities qualify for SEPs if they certify to the Energy Commission that they use certain fuel types obtained in an approved manner. MSW facilities must use

a non-combustion conversion process that meets an explicit list of operating criteria to qualify for SEPs.

Incremental geothermal production may meet the criteria for "new" in-state renewable electricity generation technology facilities described in SB 1038, and, therefore, be eligible for SEPs. The criteria for evaluating such eligibility have not yet been determined. The Energy Commission's adopted decision on Phase 1 issues states that a post-2001 repower of an existing geothermal resource must be found to be incremental as well as "new" to be eligible for SEPs.

2. Certifying Electricity Generation Facilities

SB 1078 directs the Energy Commission to "certify eligible renewable energy resources" that it determines meet the criteria of an "eligible renewable energy resource" qualifying towards meeting the state's 20 percent renewables target.

SB 1038 directs the Energy Commission to "register" facilities that are eligible for funding from the Existing Renewable Facilities Program and the NRFP. SEPs will be awarded and distributed through the NRFP. Facilities that are eligible to receive funding from these programs "…shall be registered in accordance with criteria developed by the Energy Commission…."

3. Developing an RPS Accounting System

SB 1078 directs the Energy Commission to "design and implement an accounting system" to serve three purposes: "to verify compliance with the renewables portfolio standard by retail sellers, to ensure that renewable energy output is counted only once for the purpose of meeting the renewable portfolio standard of this state or any other state, and for verifying retail product claims in this state or any other state."

SB 1078 states further that "in establishing the guidelines governing this system, the Energy Commission shall collect data from electricity market participants that it deems necessary to verify compliance of retail sellers." When seeking accounting system data from the electrical corporations, SB 1078 directs the Energy Commission to request data from the CPUC. The CPUC must collect that data from the electrical corporations and provide it to the Energy Commission within 90 days of the request.

COMMITTEE PROPOSED DECISIONS

This section provides the Committee's proposed decisions and rationale for those decisions regarding distributing supplemental energy payments, certifying electricity generation facilities, and developing the accounting system for the RPS.

Distributing Supplemental Energy Payments

As required in SB 1078, the Energy Commission must "allocate and award supplemental energy payments … to eligible renewable energy resources to cover above-market costs of renewable energy." To do so, the Energy Commission must resolve a number of eligibility, allocation, and administrative issues.

Eligibility issues include the following:

- definition of "new" and "repowered,"
- eligibility of bilateral contracts,
- potential for multiple awards ,
- what entities may receive SEPs, and
- SEP interaction with SB 90 funding.

Allocation and administrative issues are as follows:

- SEP payment terms,
- the need for financial and performance guarantees, and SEP termination,
- the availability of PGC funds, and
- the need for flexibility in developing and modifying program guidelines.

The Committee's proposed decisions and rationale on these issues are as follows.

Definition of "New"

Decision: The Committee recommends that resources that begin commercial operation on or after January 1, 2002 and meet the other eligibility requirements of SB 1038 be considered "new" and thus eligible for SEPs.

Discussion and Rationale: SB 1038 establishes the New Renewable Resources Account, but does not establish a date or method to determine when a renewable energy resource is considered "new." SB 1078 directs the Energy Commission to "provide supplemental energy payments from funds in the New Renewable Resources Account" to eligible renewable energy resources to cover the above-market costs of those resources, but like SB 1038 does not define "new."

SB 1078 does, however, direct the CPUC to establish a baseline renewable procurement level "based on the actual percentage of retail sales procured from eligible renewable energy resources in 2001." The Committee's recommendation, therefore, is consistent with the law, because any renewable energy resource commercially operating before January 1, 2002 could have been included in the baseline of an electrical corporation or other obligated entity.

The Committee's recommendation is also generally consistent with comments by Chateau Energy Inc. (CEI). Other parties, however, presented different recommendations. Calpine Corporation proposed that, for the purpose of SEP eligibility, "new" facilities are those that began operation after September 26, 1996. In addition, Calpine Corporation recommended that the designation as "new" remain in place for ten years after a facility's commercial operation date.

The Committee disagrees that facilities built between 1996 and 2002 should be eligible for SEPs. Such facilities were completed under the market conditions at the time and are operating under contract or market payments for their energy without expectation of or recourse to SEPs. Also, the most recent SB 90 New Renewable Resources Account auction, held in June 2001, defined "new" as coming on-line after October 12, 2000, and it would not make sense to now define "new" as before this date.

Renewable Energy Inc. (REI) suggested that facilities that begin operation on or after the date the legislation passed, September 12, 2002, be considered "new." The Committee prefers not to use this date because a facility that came on-line between January 1, 2002 and September 12, 2002 could not be part of any retail seller's initial baseline amount of resources, yet would also not qualify for SEP.

The California Wind Energy Association (CalWEA), The Utility Reform Network (TURN), and Vulcan Power Company suggest that new facilities eligible for SEPs should be those facilities that come on-line after the date of a retail seller's solicitation for renewable energy to meet its RPS obligation. Although the Energy Commission used a similar approach in implementing SB 90, the Committee prefers to set one fixed date for defining "new" for the RPS. Having a rolling date under SB 90 was relatively clear because the solicitations held by the Energy Commission were statewide solicitations separated by significant time. Under the RPS, multiple solicitations by different parties and with differing eligibility rules or requirements may occur within the same year, leading to quite a variety of dates where a resource could be defined as "new." Setting the eligibility for qualifying as "new" and eligible for SEP payments to a set date will be more straightforward to implement.

The Independent Energy Producers (IEP) also advocated having the "new" designation set to a fixed date. IEP proposed that the designation of "new" or "existing" should depend on funding eligibility. According to IEP, a facility should be able to qualify as "new" and eligible for SEPs for ten years and then qualify for payments from the Existing Renewable Facilities Program. The Committee disagrees with IEP, because the Existing Renewable Facilities Program was established for a specific set of

resources under specific market conditions that no longer exist. The Committee also believes that the Legislature never envisioned automatic eligibility for Existing Renewable Facilities Program payments after a facility has captured all of its New Account or SEP payments.

The Committee notes that designating a facility as "new" based on its on-line date, as described above, does not necessarily imply eligibility for SEPs. A facility that is not an eligible renewable resource, or does not satisfy eligibility criteria established by the RPS, is not eligible for SEPs even though it may be designated "new."

Definition of "Repowered"

Decision: The Committee recommends that repowered generators should be eligible for SEPs if they replace their prime generating equipment and use tax records to demonstrate that the capital investments they make equal "at least 80 percent of the value of the repowered facility," as required by SB 1038. For generators with existing long-term contracts originally entered into before September 26, 1996, only generation above and beyond what is already under contract, as determined in accordance with Public Utilities Code section 399.6 (c)(1)(C), may compete to satisfy the RPS obligation of an electrical corporation and be eligible for SEPs.

Discussion and Rationale: SB 1038 contains two provisions that affect the eligibility of repowered projects for SEPs. PUC section 383.5(d)(3) states that "Repowered existing facilities shall be eligible for funding under this subdivision if the capital investment to repower the existing facility equals at least 80 percent of the value of the repowered facility." The second provision imposes additional eligibility limits on generators with certain existing long-term contracts. For these generators, PUC section 383.5(d)(2)(C)(i) specifies that the Energy Commission may not award SEPs for renewable electricity produced and "sold under an existing long-term contract with an existing in-state electrical corporation if the contract includes fixed energy or capacity payments, except for that electricity that satisfies the provisions of [Public Utilities Code section 399.6(c)(1)(C)]."

PUC Section 399.6 (c)(1)(C) provides that if a facility produces additional electricity because of a repower or a separable enhancement, that electricity is only eligible for funding from the NRFP if it does not also receive capacity payments as part of a utility contract. The exception to this restriction is when a facility's capacity has expanded by a significant amount within the constraints of the contract and the additional generation is also above a calculated historical amount for the facility.

To establish what facilities are eligible for SEPs, the Committee must first define what constitutes a "repowered" facility and then determine how facilities will demonstrate that the capital investment made "equals at least 80 percent of the value of the repowered facility."

The Committee believes that the reason the Legislature made repowered facilities eligible was to encourage retrofitting to enhance the efficiency of existing facilities where appropriate. Therefore, the Committee recommends that for a facility to be considered "repowered," its prime generating equipment must be replaced with new prime generating equipment, that is, equipment that has not been used before. For example, to be considered "repowered," a wind generator must, at a minimum, install new turbines.

The Committee further believes that the Legislature imposed the 80 percent threshold to assure that only those facilities that are primarily "new" are eligible. However, the statute provides little guidance regarding how the Energy Commission is to determine whether the capital investment made to repower a project equals "at least 80 percent of the value of the repowered facility."

To make this determination, the Energy Commission must decide the following:

- what capital investments will be counted towards the 80 percent threshold,
- how the value of the capital investments will be established,
- the meaning of the term "repowered facility," and
- how the "value of the repowered facility" will be determined.

In their written comments, CalWEA, CEI, and Vulcan Power Company suggested that the Energy Commission should use provisions of the federal tax code to determine eligibility for repowered facilities. The Committee agrees that it is desirable to use the federal tax code to the extent possible, because it provides guidance on differentiating "capital investments" from other types of expenses such as operation and maintenance expenses. In addition, tax records can be used to establish a readily available proxy for "value" which, because it is used for another purpose, is less likely to be "gamed" to establish SEP eligibility.

The Committee believes that it can use tax records to develop detailed guidelines for generators to use in demonstrating compliance with the 80 percent threshold. One possible approach is outlined below:

1. The "capital investments" counted toward the 80 percent threshold would be capital investments for new prime generating equipment and associated structures used for structural support of the prime generating equipment.

2. The "value" of the capital investments would be determined using the original tax "basis" declared to the Internal Revenue Service to calculate depreciation. The tax basis is generally what a business pays for an item to be depreciated.

3. To determine whether the 80 percent threshold is met, the value of capital investments will be compared to the value of the "repowered facility," defined as all of new and/or existing equipment and structures at the facility. The land on which the facility sits would not be considered part of the "repowered facility."

4. The "value" of the "repowered facility" would be the sum of the tax basis declared for all of the equipment and structures in the repowered facility as of the year the facility is repowered. For new equipment and structures, the value of the repowered facility would be the original basis; for existing equipment and structures, the value of the repowered facility would be the basis as adjusted for depreciation.

The Committee recognizes that when generators apply to the Energy Commission for eligibility certification for the RPS and SEPs, they will not yet know the actual cost of the new prime generating equipment that they intend to install. Thus, it will be necessary for the Energy Commission to certify these generators based on estimates that would be checked against tax returns filed after the repowered facility goes into operation. The Committee further recognizes when the Energy Commission develops detailed guidelines, it may also be desirable to establish guidelines for generators that wish to repower only a portion of an existing facility or to repower a facility in stages.

For generators with existing contracts that wish to repower, SB 1038 imposes further restrictions. As noted above, the Energy Commission may not award SEP payments for renewable electricity produced and "sold under an existing long-term contract with an existing in-state electrical corporation if the contract includes fixed energy or capacity payments, except for that electricity that satisfies the provisions of [Public Utilities Code section 399.6(c)(1)(C)]."

The provisions of section 399.6 (c)(1)(C) assure that for facilities with an existing long-term contract entered into before September 26, 1996, production incentives are available only for additional generation over and above that which was originally contracted for. The provisions of this section also specify the procedures to determine what qualifies as additional generation. If a repowered facility has an existing long-term contract governed by section 399.6(c)(1)(C), only the quantity of the electricity generated considered additional generation under section 399.6 (c)(1)(C) may compete to satisfy the RPS obligation of an electrical corporation and be eligible for SEPs. If an existing long-term contract expires, then the renewable generator would be eligible for funding as a "repowered" facility on the same terms as other generators.

Eligibility of Bilateral Contracts

Decision: The Committee recommends that bilateral contracts between electrical corporations and renewable energy resources outside of a competitive solicitation are not eligible for SEPs.

Discussion and Rationale: The Committee believes that allowing SEP awards for contracts established outside an RPS solicitation is inconsistent with the RPS structure that ties SEPs to market price referents determined in specific solicitation cycles. In addition, allowing bilateral contracts to be eligible for SEPs could also undermine the RPS by circumventing the least-cost-best-fit analysis required under SB 1078 and is inconsistent with the goal of using a robust competitive process to allocate public funds.

Under the RPS, SEP amounts are tied explicitly to costs above an applicable market-price referent that is part of a utility solicitation process. The CPUC is prohibited from informing bidders in a solicitation about the applicable market price referent until the solicitation is held. Similarly, the CPUC is prohibited from receiving the results of a solicitation until after determining the applicable market price referents. Because a market price referent cannot be clearly applied outside of a utility solicitation, SEPs cannot result from bilateral contracts.

CalWEA submitted comments supporting this position, but noted that projects with SB 90 awards could reasonably be allowed to keep their awards and enter into a bilateral contract. The Committee agrees that projects with SB 90 awards do not result in the SEP issues raised above and, therefore, should not be required to relinquish those awards if they enter into a bilateral contract with a retail seller. However, should a project with an SB 90 award choose to participate in an RPS solicitation and be eligible for SEPs, the Energy Commission would require the project to relinquish that award. This limitation is discussed in more detail in a later section of this report

Entities That May Receive SEPs

Decision: The Committee recommends paying SEPs to the entity with which an electrical corporation or other obligated entity holds a long-term contract (ten years or longer) for renewable energy resources.

Discussion and Rationale: SB 1078 states that “supplemental energy payments shall be awarded only to facilities that are eligible for funding under this subdivision.” The Committee does not interpret this to mean that only individual renewable energy generators may contract with obligated entities and be eligible for SEPs. It is possible that electrical corporations or other obligated entities will contract with entities other than the renewable energy generators to satisfy their obligation.

Wholesale power marketers and other financial intermediaries may acquire the rights to the energy and renewable energy attributes or certificates from a renewable energy resource for its generation along with the rights to sell those products. The Committee, therefore, recommends awarding SEPs to the entity that holds the contract with an electrical corporation or other obligated entity that satisfied their RPS obligation, provided that the contracting entity can identify and establish its rights to sell renewable energy from a certified renewable energy resource. Further, the Committee recommends that any renewable facility that sells its generation to a contracting entity be obligated to document the facility’s eligibility and generation.

Comments from Calpine, CalWEA, CEI, Vulcan, and Renewable Energy Inc. support this recommendation, as did the general discussion among all parties at the workshop.

SEP Interaction with SB 90 Funds

Decision: The Committee recommends that a project holding a conditional funding award from the Energy Commission's New Renewable Resources Account under SB 90 may participate in an IOU solicitation under the new RPS structure in hopes of securing a PPA, but cannot receive SEPs in addition to the SB 90 award.

The Committee recommends that to participate in a specific IOU solicitation, bidders with SB 90 awards whose projects are not yet on-line must state their intention to either (1) keep the SB 90 award and agree to be ineligible for SEPs or (2) relinquish the SB 90 award and compete for potential SEPs. Similarly, on-line projects that have already received payments from the New Renewable Resources Account under SB 90 cannot receive SEPs unless they state their intention to relinquish their SB 90 award when they submit their SEP bid. Further, any funding awarded through SEPs will be reduced by the amount of any payments already made to these projects under SB 90.

The Committee recommends that a winning bidder that chooses to keep its SB 90 award can receive payments under that award's terms and conditions, but is ineligible for SEPs. A winning bidder that chooses to be eligible for SEPs must relinquish its SB 90 award, or any remaining payments under that award, once it executes a contract with a utility, regardless of whether or not the bidder ultimately qualifies for SEPs. However, if a bidder does not secure a contract under the RPS solicitation, the bidder will not be required to relinquish its SB 90 award.

The Committee also recommends that projects may also retain their SB 90 awards if they enter into a bilateral contract with an IOU outside of a solicitation, should the CPUC allow such procurement. Projects that enter into contracts or agreements with other retail sellers will face similar rules governing interaction with SEP payments. These rules will be established once the CPUC specifies the process by which other retail sellers are obligated under the RPS.

Discussion and Rationale: Under the SB 90 program that began in 1998, developers of prospective new renewable energy facilities competed for a fixed amount of PGC funding in the form of production incentives of up to 1.5 cents per kilowatt-hour (kWh) for the first five years of generation. Developers were not required to have a power purchase agreement (PPA) to be able to bid for funding.

The Energy Commission held three separate auctions — the first in June 1998, the second in October 2000, and the third in June 2001. The October 2000 and June 2001 auctions were structured to encourage rapid development of winning projects to provide additional generation during California's energy crisis in 2000-2001.

The auctions were successful in awarding funds to a diverse group of the most efficient prospective renewable energy generators. 71 renewable projects, totaling 1,271 megawatts (MW) of capacity, hold active funding awards resulting from the auctions. However, because of changes in California's wholesale power market, only about 20

percent of the capacity that was originally awarded funding has completed development and construction and is commercially operating.

Currently, 40 projects, totaling 259 MW, are on-line and receiving incentive payments. Developers of 31 projects representing more than 1,000 MW of capacity still have conditional funding awards that they could use if they are able to complete development and construction, and begin commercial operation. Of these 31 projects, the Energy Commission staff expects six totaling 226 MW to come on-line in 2003. The remaining projects are scheduled to come on-line in 2004 and 2005.

The October 2000 and June 2001 auctions imposed significant reductions of bidders' expected PGC awards for projects coming on-line after certain dates specified in each auction. Of the 31 projects not yet on-line, 17 projects currently have awards that have been reduced by 50 percent; depending on when the projects come on-line, the awards could be further reduced or even cancelled.

One of the major barriers auction winners have faced while trying to bring their projects on-line has been the difficulty in securing PPAs. The Committee, therefore, does not want to establish rules that will preclude a project holding an SB 90 award from securing a contract with a utility as a result of an RPS solicitation. However, the Committee also believes that allowing projects to choose between keeping their SB 90 awards or receiving SEPs after the results of the procurement solicitation are determined could potentially dismantle the results of the selection process.

By allowing projects with SB 90 awards to participate in RPS solicitations with the understanding that they must relinquish their SB 90 awards to be able to receive SEPs, the Energy Commission maintains its support of new facilities with conditional SB 90 funding while preventing those projects from "double dipping" PGC funds or taking unfair advantage of the procurement process.

The comments from CalWEA, TURN, PG&E, SDG&E, and Vulcan Power are generally consistent with the Committee's recommendation, although PG&E suggests that a project should not be required to give up its SB 90 award until after it has been selected as a winner. CEI further stated that an SB 90 award should not be forfeited until after a utility contract is signed and SEPs have been approved.

Calpine Corporation proposed that SB 90 awardees should be eligible for SEPs if they give up their award. However, in addition to choosing between the SB 90 award and SEPs, Calpine also suggests that a bidder should be given the option of withdrawing its bid after the market price referent has been revealed. The Committee believes this option invites gaming and would disrupt the results of the least-cost-best-fit analysis required under SB 1078.

SEP Payment Terms

Decision: The Committee recommends paying SEPs only for actual generation by an eligible renewable energy resource. Generation that has been curtailed or has otherwise not occurred is not eligible for SEPs, even if a facility's contract specifies curtailment payments or provision of replacement energy.

The Committee also recommends paying SEPs for contracts with terms of ten years or longer with the electrical corporation or other obligated entity. Contracts for a longer term than ten years will also be eligible for ten years of SEPs. In accordance with SB 1038, the CPUC may authorize shorter-term contracts, but contracts for less than ten years are not eligible for SEPs.

Finally, the Committee recommends paying SEPs monthly, with further operational details to be determined when the guidelines for the NRFP are developed.

Discussion and Rationale: SB 1078 states that the Legislature requires "all electrical corporations to procure a minimum quantity of output from eligible renewable energy resources as a specified percentage of total kilowatt-hours sold to their retail end-use customers each calendar year." This statement establishes the Legislature's intent to establish an RPS based on generation output from renewable energy resources, measured in kilowatt-hours, rather than on capacity. To pay SEPs on any basis other than energy generated would be at odds with this intent.

Payments from the Renewable Energy Program through the SB 90 program are made on a monthly basis. Calpine, CalWEA, CEI, and Vulcan suggested that SEP payments should be made on the same schedule as PPA payments. Many parties proposed that payment on a monthly basis would be appropriate as well as consistent with the potential PPAs.

Potential for Multiple Awards

Decision: The Committee recommends allowing one facility to apportion its electricity generation into two or more separate contracts, with energy from each of these contracts qualifying for SEPs, provided that the generation under each contract is separately metered. However, facilities are only eligible for SEPs for the first ten years of generation from their initial RPS contract(s).

Discussion and Rationale: The Committee recommends that the energy produced from a renewable energy resource associated with a contract with electrical corporations only be eligible for SEPs once. SB 1038 specifies that SEPs "shall be paid for the lesser of ten years, or the duration of the contract with the electrical corporation." The Committee does not want to provide SEPs for multiple short-term contracts with electrical corporations, because it could create incentives for short-term contracts that are counter to the intent of SB 1038.

Although a generator may find it desirable to sell its entire output to one retail seller, the Committee believes that the generator should not be prevented from packaging its generation to more than one retail seller. This option will provide flexibility to both the utilities and the generators as they pursue PPAs.

There may be cases where one renewable energy resource sells portions of its output to more than one retail seller through separate contracts. In such a case, one facility could qualify for more than one SEP award, with each SEP award tied to the amount of energy contracted for by each retail seller. The generator would be required to report the entire amount of energy generated from the facility to the Energy Commission.

One unit of energy, or percent of production, cannot receive more than one SEP award. For example, the renewable energy resource may have a contract to sell 30 percent of its output to one retail seller, under terms that qualify it for an SEP award. This portion of the generation would not qualify for a second award. The generator would report its monthly generation to the Energy Commission and also report the deliveries under contract to the retail seller. The remaining 70 percent of the output from the generator could also be eligible for SEPs if the generator successfully won a contract and an SEP award for that portion of its generation.

The Committee recognizes that it must necessarily defer to a later date the rules related to RPS compliance for ESPs and CCAs. Therefore, the Committee makes no recommendations regarding multiple awards for ESPs and CCAs at this time.

Financial and Performance Guarantees and SEP Termination

Decision: The Committee recommends that PPAs with the electrical corporations address financial and performance issues related to renewable energy resources that are awarded SEPs. The Committee further recommends terminating SEPs if the PPA that is the basis of the SEP award is terminated. The Committee does not contemplate holding an auction for SEPs for solicitations by electrical corporations at this time. Auctions for the distribution of SEPs to other retail sellers may be appropriate, and the Committee will make such a determination during Phase 3.

Discussion and Rationale: SB 1038 provides the Energy Commission with the authority to “require applicants competing for funding to post a forfeitable bid bond or other financial guaranty as an assurance of the applicant’s intent to move forward expeditiously with the project proposed.” Further, SB 1038 directs the Energy Commission to reduce or terminate SEPs “for projects that fail either to commence and maintain operations consistent with the contractual obligations to an electrical corporation, or that fail to meet eligibility requirements.”

The CPUC, however, is in the process of establishing RPS compliance rules for electrical corporations as a part of the electrical corporations’ overall procurement planning proceeding. The Committee expects that the electrical corporations will satisfy their obligations to procure renewable energy resources through their own procurement

methods, and does not see a role for Energy Commission hosted auctions for SEP funding.

Therefore, because the Energy Commission does not currently contemplate hosting auctions for SEP funding at this time, the Committee does not recommend establishing financial or performance standards above those required of the facilities under their PPAs with the electrical corporations. If the PPA that is the basis of the SEP award is terminated for non-performance or any other reason, the Committee recommends terminating the SEP award at the same time. The Committee also welcomes comments on the need for and potential structure of a process to allow SEP awardees whose utility contracts have been terminated to petition the Energy Commission for continuation of their SEP payments.

Availability of Public Goods Charge Funds

Decision: The Committee recommends that the CPUC transmit market price referent information to the Energy Commission at the same time that information is revealed to the utilities. The Committee further recommends that the CPUC direct the utilities to transfer the bid prices of selected projects to the Energy Commission at the same time they transmit that information to the CPUC.

The Committee recommends that the Energy Commission compare the requested SEPs with the availability of PGC funds to determine if PGC funds are adequate to cover SEPs for all the applicable winning bidders in the utilities' solicitation. If PGC funds are inadequate, then the Committee recommends that the Energy Commission identify which bidders could be fully funded under the least-cost-best-fit ranking required under SB 1078, so that projects with the best ranking would be awarded SEPs first. If funding is available to cover only a portion of the SEPs for which a bidder might otherwise be eligible, then that bidder will have the option to either take the partial award or decline the award entirely.

Finally, the Committee recommends that the Energy Commission notify the CPUC, IOU, and bidders of the availability of PGC funds within 15 days of receiving the bid data, market price reference data, and least-cost-best-fit ranking, and that the Energy Commission confirm the availability of PGC funds for each winning bidder within 30 days of when the CPUC approves contracts needing SEPs.

Discussion and Rationale: SB 1038 directs the Energy Commission to award SEPs to renewable energy resources "selected by retail sellers to fulfill" their RPS obligations. SB 1078 requires the Energy Commission to "Allocate and award supplemental energy payments pursuant to [Public Utilities Code] Section 383.5 to eligible renewable energy resources to cover above-market costs of renewable energy." Further, SB 1078 states that, "the commission [CPUC] shall consult with the Energy Commission in calculating market prices …" SEPs are based on the difference between the bid price and market price referent if the bid price exceeds the market price referent.

Once a utility completes its RPS procurement solicitation and selects winners, the CPUC will announce the market price referent. Pursuant to SB 1078, the CPUC shall review the results of a solicitation and accept or reject proposed contracts based on consistency with the utility's approved renewable procurement plan. Further, if the CPUC determines that the bid prices are elevated due to a lack of effective competition among bidders, the CPUC is required to direct the utilities to renegotiate such contracts or conduct a new solicitation.

The Committee recognizes that the execution of PPAs for winning bidders of an RPS procurement solicitation may depend upon assurance that the bidder will receive SEPs. Consequently, it is important for the Energy Commission to make a timely determination that a bidder is eligible for the RPS and SEPs, and that there are sufficient PGC funds to cover any SEPs needed by winning bidders.

However, the Energy Commission must ensure that all funding criteria are met before issuing a final funding award. The Committee also recognizes that the Energy Commission's requirements must be balanced with the need to assure parties that SEPs are available to meet bidders terms. Therefore, the Committee recommends that the Energy Commission will notify winning bidders of their SEP eligibility and the amount of PGC funds that are available to them.

The Energy Commission will be able to notify winning bidders of the potential PGC awards, but will not be able to approve final funding award agreements until a winning bidder has:

1. executed a PPA with the utility,

2. completed any required environmental review, such as those required under the National Environmental Policy Act or the California Environmental Quality Act (CEQA), and

3. submitted copies of the project's required environmental documents — certified final environmental impact report/statement, negative declaration, exemption letter, and so on — to the Energy Commission so that the Energy Commission may rely on and consider these documents pursuant to Section 15096(f) of the CEQA Guidelines (Title 14, California Code of Regulations, Division 6).

For projects already operational, the Energy Commission will only approve a final funding award agreement once the project developer has delivered the necessary environmental documents to the Energy Commission.

The Committee recommends that the CPUC transmit information about the market price referent at the same time the CPUC reveals it to the utilities, and that the CPUC direct the utilities to transmit to the Energy Commission the bid price, expected energy price, contract term, and other pertinent information for selected projects at the same time the utilities transmit that information to the CPUC. These recommendations are supported

by Joint Principles developed by TURN and SDG&E, which call for utilities to provide relevant information to the Energy Commission at the time a PPA is submitted for CPUC approval so that the Energy Commission can determine the SEPs needed to support expected contract obligations.

The Joint Principles further recommend that the Energy Commission make a preliminary determination regarding the availability of PGC funds before CPUC action approving any contracts. The Committee agrees that the Energy Commission should make an initial determination on PGC availability based on the market price referent established by CPUC, the results of the IOU's procurement solicitation, and the Energy Commission's evaluation of the winning bidders' eligibility for the RPS and SEPs.

To make such a determination, the Energy Commission will first verify that each winning bidder was certified or pre-certified as eligible for the RPS and the SEP. For each winning bidder with a bid price higher than the market price referent, the Energy Commission will calculate the amount of PGC funds needed to fund the SEP. This evaluation will depend on the bid price, the market price referent, and the expected energy deliveries from the bidder.

Comments from Calpine Corporation, CalWEA, SDG&E and Vulcan Power Company support allocating PGC funds in order of the least-cost-best-fit ranking in the event that PGC funding is not sufficient to meet the demand of a solicitation. CalWEA added that if the funds are sufficient to partially cover the SEPs of a bidder, then the facility, together with the contracting retail seller, should have the option of down-sizing the contract or accepting a smaller award. CalWEA further stated that if the award is declined, it should go to the next least-cost facility. The Committee agrees with these comments.

PG&E, TURN, and SDG&E all commented on the need to coordinate the processes of certifying eligible renewable resources, selecting winning bidders, and awarding SEPs. PG&E and SDG&E stated that "sequencing the utility and the CEC processes needs to be seamless in order to facilitate an effective and efficient RPS implementation." The Committee agrees and believes it has proposed an appropriate sequence.

Flexibility in Guidebook Development

Decision: The Committee recommends that the Energy Commission preserve flexibility in developing guidebooks and implementing the RPS to reflect ongoing efforts at the CPUC as well as respond to market developments.

Discussion and Rationale: The Committee recognizes that implementing the RPS will require further public input to develop the details of the Committee's recommendations. Also, the CPUC's rules for implementing the RPS are still under development and will continue to be refined over time, which reinforces the need for flexibility in the guidebook development process.

Deferred Issues

The Committee is deferring decisions on several issues. First, any decision on requirements for public works projects must be deferred because the Energy Commission has no say in how the public works/prevailing wage issue will be resolved; the Energy Commission will be required to apply rules determined by the Department of Industrial Relations.

Several issues require a decision or guidance from the CPUC. For example, SB 1038 provides the Energy Commission the ability to establish caps on SEPs "designed to provide for a viable energy market capable of achieving" the RPS goals. However, design of any caps on SEPs will depend on the implementation of the least-cost-best-fit bid ranking criteria developed by the CPUC. The Committee recommends deferring its decision on the cap structure until stakeholders have an opportunity to review CPUC Decision 03-06-071 and provide comments to the Committee on the decision's impact on SEP caps.

SB 1038 also states that "the Energy Commission may provide preference to projects that provide tangible demonstrable benefits to communities with a plurality of minority or low-income populations." Again, the Committee defers its decision until stakeholders have an opportunity to review CPUC Decision 03-06-071 and provide comments to the Committee on implementation of this language.

SB 1038 directs the Energy Commission to manage SEPs funds "in an equitable manner in order for retail sellers to meet their" RPS obligation. Similarly, SB 1078 directs the CPUC to institute rulemakings to determine the manner in which ESPs and CCAs will participate in the RPS. Because those proceedings are not yet underway, the Committee defers any decision on funding allocations between providers or classes of providers until the CPUC's proceedings are complete.

Certification

SB 1078 directs the Energy Commission to "certify eligible renewable energy resources that it determines meet the criteria as an eligible renewable energy resource." The Energy Commission currently registers renewable energy resources for several other purposes, including the Renewable Energy Program established under SB 90 and the Existing Renewable Facilities Program established under SB 1038. To certify eligible renewable energy resources, the Energy Commission must consider the following:

- certification and registration eligibility,
- certification data, documentation, and verification, and
- certification amendments.

Certification and Registration Eligibility

Decision: The Committee recommends that if a renewable energy resource sells energy to a retail seller to meet an RPS obligation, the renewable energy resource must be certified by the Energy Commission as meeting the eligibility criteria defined in the Energy Commission's *Renewable Portfolio Standard: Decision on Phase 1 Implementation Issues*. The Committee further recommends that projects proposed, under development, or in construction be eligible for provisional or "pre-" certification based on the owners' self-certification of the proposed project, subject to further verification once the project has been completed.

The Committee recommends that renewable energy resources that meet the definition of renewable for the purposes of the Renewable Energy Program or the Power Source Disclosure Program but that do not meet the definition of an eligible renewable energy resource for the purposes of the RPS may continue to be "registered," rather than "certified."

Discussion and Rationale: In their comments, SDG&E stated that the Energy Commission should establish a procedure that would allow facilities to be certified before submitting bids, and that in no event should certification occur after the utility submits contracts to the CPUC for approval. SDG&E also asserted that a utility must have a final assessment from the Energy Commission as to whether a facility is eligible for the RPS to ensure that the utility takes actions that will satisfy its annual procurement target. The Committee agrees and believes that pre-certification is necessary to prevent ambiguity about the eligibility of proposed renewable energy resources that respond to RPS solicitations.

CEI commented that the Energy Commission should differentiate between "registration," "certification," and "verification." According to CEI, "registration" simply generates a list of participants and does not involve great detail for each registered renewable generator. "Certification" generates a more limited and detailed list of generators, and should be subject to independent third-party audits paid for by generators if and when the Energy Commission deems the audit to be necessary to confirm RPS eligibility. "Verification" is the enforcement step whereby the Energy Commission is mandated and empowered to ensure credibility. In its comments, CEI supported the idea of establishing eligibility before the issuance of a Request for Offers, with eligibility for the RPS documented in a generator's bid submission.

PG&E maintained that certification should be mandatory for all RPS participants and also argued that every "eligible renewable energy resource," as defined by PUC section 399.12(a), in the state should be registered. PG&E's argument is that even if generation from those facilities is not intended for RPS participation today, it could be in the future.

The Committee agrees with CEI's and PG&E's comments.

Certification Data, Documentation, and Verification

Decision: The Committee recommends a self-certification procedure for renewable energy resources. To verify the accuracy of self-certification claims, the Energy Commission will do the following:

1. institute an audit procedure to conduct spot checks of the documentation provided for self-certification,

2. post information on the Energy Commission website to support industry self-policing, and

3. retain the right to request additional documentation at any time to verify certification.

The Committee also recommends that the Energy Commission accept documentation from other government agencies, where applicable, for purposes of self-certification.

Discussion and Rationale: The Committee believes that these measures will assure the integrity of the RPS program and ensure that the RPS goals are met in accordance with the statutes. The Committee wishes to maximize the effectiveness of the verification efforts without imposing burdensome costs on participants. A spot-check audit procedure provides the necessary assurances without imposing unreasonable costs. Furthermore, posting information publicly will help to make the certification process as transparent as possible and ensure that the Energy Commission receives accurate information. In addition, making the data public allows other parties to conduct their own check of the information so that they may notify the Energy Commission of any misrepresentations.

Certification data requirements will vary by renewable energy resource type, based on the eligibility criteria for RPS compliance established by the *Renewable Portfolio Standard: Decision on Phase 1 Implementation Issues*. For example, fuel limitations for biomass facilities require documentation irrelevant to a wind generator. In verbal comments at the May 12 and 13, 2003 staff workshop, IEP proposed that verification of eligible fuel for a biomass generator could be based on self-certification by the fuel suppliers, submitted under penalty of perjury.

PG&E argued that certification should be enforced through periodic reporting and random site audits, but also stated that participants and regulators must be mindful not to overburden enforcement resources or cause unreasonable delays in certifying and verifying renewable generation. PG&E stressed that the rules for the application and certification process should be as straightforward as possible so as not to discourage participation.

In regards to data collection, CEI recommended that the Energy Commission use existing data streams and databases whenever possible, including the generator's permit-related environmental submissions. CEI further maintained that the Energy

Commission should determine who has legal oversight for each specific eligibility criterion, and that if no other agency has legal responsibility for oversight, interagency agreements may be needed.

Regarding potential penalties for non-compliance, the Committee agrees with comments made during the staff workshop that penalties are unnecessary beyond those already included in the PPA between the retail seller and the renewable energy resource.

Certification Amendments

Decision: The Committee recommends that certified facilities must notify the Energy Commission in a timely manner of any material changes in information previously submitted to the Energy Commission, and that facilities failing to do so should be subject to disqualification. The Committee further recommends that certification be renewed every year to capture facility changes and to confirm that all certified renewable energy resources remain eligible for the RPS. In addition, if a certified or pre-certified entity does not respond to the Energy Commission's request for an information update in a timely manner, it will risk losing its certification status.

Discussion and Rationale: SDG&E submitted comments asserting that the Energy Commission should develop a system to verify a facility's continuing eligibility during the term of its participation in the RPS. The Committee agrees that data submitted in the application for certification may change over the duration of the RPS program. While some items will remain constant, such as the location of the facility, other items such as fuel usage, facility size, or facility ownership may change, requiring more frequent verification. Information submitted in the certification process will document a facility's eligibility for the RPS, but it is vital to the program to ensure that such records are current and accurate.

Accounting System

SB 1078 requires the Energy Commission to design and implement an accounting system to verify retail sellers' compliance with the RPS. The primary purpose of the proposed accounting system is to:

1. verify compliance with the RPS by retail sellers,

2. ensure that renewable energy output is counted only once for the purpose of meeting the RPS of this state or any other state, and

3. verify retail product claims in this state or any other state.

According to SB 1038, a secondary purpose of the proposed accounting system should be to track the amount of renewable electricity produced and sold by SEP-eligible

renewable generators on a monthly basis. Because the *Renewable Portfolio Standard: Decision on Phase I Implementation Issues* provides that out-of-state renewable power be eligible for the RPS, the accounting system must also be able to verify generation and contracts from out-of-state facilities.

This section covers the following:

- recommended accounting systems
- the interim accounting system
- the long-term accounting system
- required participants in the accounting system
- long-term system source of data
- transactions tracked in the electronic accounting system
- type of information tracked by the electronic accounting system
- public access to electronic system data
- in-state delivery requirement
- participating in a WECC accounting system
- determining "baseline" designation

Recommended Accounting Systems

Decision: The Committee recommends that the Energy Commission (1) use an interim contract-path accounting system to verify RPS compliance for 2003 and 2004; and (2) develop a long-term electronic-path accounting system in coordination with the Western Governors' Association (WGA) that can record renewable generation and transactions through the system starting in 2005 and meet the needs specified in SB 1078:

1. verify compliance with the RPS by retail sellers,

2. ensure that renewable energy output is counted only once to meet the RPS of this state or any other state, and

3. verify retail product claims in this state or any other state.

For both the interim and long-term systems, the Committee recommends that in-state and out-of-state renewable energy generators that are eligible for the RPS must first be certified by the Energy Commission.

Discussion and Rationale: Based on comments received at the May 13, 2003 workshop regarding evaluating options for verifying RPS compliance, the Committee examined two general categories of RPS accounting systems: contract-path and electronic-path accounting. There were no written or oral comments suggesting any other accounting methods for either the interim or long-term accounting systems.

For the purposes of this proposed decision, a *Contract-path Accounting System* refers to an accounting methodology whereby individual contracts and financial settlement

data are used to verify renewable purchases. Such a system usually involves some sort of manual review of contracts and receipts, although the information may be entered into a database or other electronic format.

An *Electronic Accounting System* refers to a system whereby financial settlements data are automatically entered into an electronic system, eliminating or minimizing the need to do manual review of contracts or receipts. An electronic accounting system is based on creating renewable certificates for each increment of electricity generated. The Committee recognizes that the CPUC is currently deliberating whether these certificates are allowed to be traded separately from the underlying electricity.

The immediate need for the accounting system is to verify energy transactions for 2003 and 2004. For an electronic system even to be a possibility for 2003, it should have been in place January 1, 2003. Likewise, for an electronic accounting system to be available for 2004, it would have to be in place by January 1, 2004. Based on oral comments received from Automated Power Exchange (APX, Inc.) and Clean Power Markets (CPM) at the May 13, 2003 staff workshop, the design of the software for even a relatively simple electronic accounting system can take about six months to develop. Consequently, the Committee recommends using a contract-path system for the interim accounting system while a long-term electronic-path accounting system is being developed.

The Committee's recommendations for the interim and long-term accounting systems are described below.

Interim Accounting System

Decision: The Committee recommends adapting the verification process used for the Energy Commission's existing Power Source Disclosure Program to verify claims made with regards to RPS obligations, on an interim basis, for compliance years 2003 and 2004.

Discussion and Rationale: The Committee believes that adapting the Power Source Disclosure Program is the most feasible way to ensure that the statutory requirements of SB 1078 and SB 1038 are fulfilled. Under this program, retail providers submit annual reports to verify their retail product claims. These reports are examined for discrepancies by Energy Commission staff and an independent third party auditor using a previously-established protocol for agreed-upon procedures. An auditor's report is required for all retail providers, including the IOUs, with the exception of municipal utilities with only one product.

The Energy Commission staff believes that the verification process for the Power Source Disclosure Program can be modified relatively easily and that a modified protocol for agreed-upon procedures can be ready to verify 2003 transactions by the first quarter of 2004.

The adaptation requires the Energy Commission to revise its current regulations for the Power Source Disclosure Program (Title 20, California Code of Regulations, sections 1390 et seq.), modifying the existing Power Source Disclosure forms, and creating a new protocol for agreed-upon procedures to instruct independent third-party auditors how to verify RPS claims in addition to Power Source Disclosure claims. The protocol for agreed-upon procedures already in place will be amended to accommodate verification of RPS obligations.

Specifically, the Power Source Disclosure forms should be modified to allow entities to verify their compliance with the RPS, including, but not limited to, the following:

- demonstrating that the retail seller purchased enough renewable electricity to meet their RPS obligation,
- demonstrating that the renewable electricity purchased is eligible under the California RPS and is certified by the RPS program,
- attesting that the retail seller's contracts include all environmental and renewable energy attributes associated with the production of electricity, or "RECs," as defined by CPUC Decision 03-06-071. The attestation would ensure that these are not "energy-only" contracts, unless otherwise deemed appropriate by the CPUC, and
- attestations ensuring that the generator is not double-selling renewable electricity or its generation-related attributes, or RECs, to another party, including meeting the RPS requirements of another state.

The Committee considered whether the interim accounting system should be designed to accommodate verification of other claims or voluntary activities. At this time, the Committee recommends modifying the Power Source Disclosure Program forms only enough to meet the statutory requirements under SB 1078 and SB 1038. If retail sellers want to verify other claims or activities, they are free to hire an auditor to verify these claims or activities. There is no need for the Energy Commission to devote resources to developing an interim accounting protocol for such claims, or trying to anticipate what kinds of claims retail sellers might want to voluntarily verify.

The Energy Commission received a number of comments regarding the advantages and disadvantages of both contract- and electronic-path accounting systems. SDG&E commented that the interim system should be a contract-path accounting system based on "metered data scaled down from the scheduling coordinators," presumably to account for line losses. CEI also was supportive of an interim contract-path accounting methodology. Similarly, PG&E indicated that they were comfortable that current sources of data can be used in a contract-path accounting and verification system to meet the state's interim needs.

CPM suggested that an interim system should be a simple, flexible electronic system that will provide lessons for the development of the long-term system while allowing

retail sellers to gain experience using an electronic system. CPM believed that such a system could be developed cost-effectively. Although the Committee agrees with CPM that an electronic system might be a superior option, because of time constraints the Committee recommends adapting the verification process for the Power Source Disclosure Program for the compliance years 2003 and 2004.

Powerex Corporation asserted that a contract-path accounting system would be easier to implement if the Energy Commission simply allowed companies to maintain records and to have those records available to an independent auditor. The Committee believes that this approach will not provide the level of verification required to fulfill the statutory requirements under SB 1078, and, therefore, does not recommend using this approach.

Long-term Accounting System

Decision: The Committee recommends developing a long-term electronic accounting system for the compliance year 2005 and beyond that will be able to meet the statutory requirements of SB 1078 and SB 1038. The electronic accounting system that the Committee proposes for RPS accounting will issue renewable energy certificates (RECs) for every megawatt-hour (mWh) generated by eligible renewable generators. Generators selling renewable electricity for RPS purposes must be account holders in the accounting system. Generators that are not eligible for the RPS but that want to participate in the electronic accounting system may apply to be account holders. The details of applying for an account will be defined during the design of the electronic accounting system.

The long-term system will be designed so that a unique electronic record — known as a REC — will be created for each mWh of renewable energy generated by a registered generator. Once created, the REC will be deposited into the generator's account. IOUs and other market participants such as CCAs, ESPs, publicly-owned utilities, generators, and intermediaries can transfer RECs between accounts, for example from the generator to a retail seller with whom the generator has a contract, and use the RECs as a mechanism to verify that a retail seller has acquired enough renewable energy to fulfill their RPS obligation. Both the buyer and the seller must confirm the transaction before it is officially entered into the system (e.g. quantity and whether bundled or unbundled with energy). Once a REC is used to satisfy an RPS requirement, it will be marked as "retired" so that it cannot be resold or claimed by any other party, or used for any other purpose.

The Committee acknowledges that decisions about whether and under what conditions RECs can be traded separately from electricity under the California RPS are the subject of ongoing deliberations at the CPUC. The Committee does not pre-judge those decisions here, but does note that the long-term electronic system that the Energy Commission envisions would be able to meet the state's RPS verification needs in either instance.

Discussion and Rationale: The Committee recommends adopting a long-term electronic-path accounting system for a variety of reasons, including:

- ease of administration
- low long-term costs
- assurances against double counting
- facilitation of ESP participation
- support of secondary purposes

Ease of Administration: Electronic accounting systems are easy to administer and use because they minimize the need to manually review contracts or rely heavily on attestations. Renewable purchases are easily tracked by a review of the electronic accounts. Unlike contract path systems, there is no need to follow the path of electricity contracts to determine compliance.

As the number of market participants increases, the ease of administering an electronic accounting system becomes even more important. Based on the Energy Commission's experience in administering and operating contract path accounting systems for the Customer Credit Subaccount and the Power Source Disclosure Program, the Committee believes it would be too challenging to administer a contract path verification system for the RPS, especially since the RPS applies to IOUs and is also expected to apply to ESPs and CCAs.

Low Long-Term Costs: SDG&E, the Center for Energy Efficiency and Renewable Technologies (CEERT), and CPM commented that an electronic system would be less labor intensive to implement and more efficient in the long run for California. The Alliance of Retail Energy Markets (AReM) maintained that the electronic system would be no more costly than a contract-path system for the state. The Committee agrees with these comments. Although establishing an electronic system may initially be more costly, the ongoing costs and staff requirements are low. The Committee believes that an electronic accounting system will, over time, be less costly to retail sellers than conducting a detailed annual audit.

Assurance of No Double Counting: AReM, SDG&E, and CPM commented that a REC-based electronic system is superior to a contract-path approach for preventing "double counting" of renewable energy output. In contrast to a contract-path approach, an electronic accounting system would enable regulators and potential buyers to easily and relatively conclusively determine whether or not the output of a given renewable resource has been counted toward a retail seller's RPS obligations.

The Committee agrees that an electronic accounting system is superior in preventing double counting. Since a single REC is generated for every unit of electricity generation, REC ownership establishes the property rights needed for suppliers to make credible claims. The electronic system provides a clear, consistent process for transferring that property right between parties. In contrast, a contract-path accounting system forces regulators to rely on paper contracts, attestations, and after-the-fact reviews. Assurance

against double counting cannot be provided as firmly and securely as under an electronic accounting system.

Facilitation of ESP Participation in the RPS: AReM, TURN and CEERT commented that tradable RECs play a key role in enabling ESPs to comply with RPS requirements in other states in a cost-effective manner. Unlike utilities, few ESPs are in a position to enter into long-term contracts for renewable energy and capacity. The Committee recognizes that whether RECs can be traded separately from electricity is a decision that will need to be determined in the later phase of this proceeding, and that unbundled RECs may not be allowed to satisfy RPS obligations. Nonetheless, it is reasonably clear that many ESPs will seek to rely on RECs purchased in the open market to satisfy their RPS obligations. The Committee believes that an electronic system is best positioned to meet those potential needs in the future, and notes that the CPUC has made a similar judgment in Decision 03-06-071.

Supports Secondary Purposes: The creation of an electronic accounting system may also have ancillary market benefits that are consistent with the CPUC and Energy Commission's goal of increasing renewable generation in the state. These benefits may come from ensuring credibility of voluntary renewable markets, and facilitating retail REC-only products and the verification of the renewable energy purchases of publicly owned utilities. By developing an electronic accounting system for RPS compliance, California will also be creating a system that may facilitate and expand other demands for renewable energy in, and potentially outside, the state. AReM, WGA, and other stakeholders at the workshop supported these secondary benefits.

Nearly all comments received were explicitly in favor of an electronic accounting system for the long term, and no comments were opposed. AReM, CEERT, SDG&E, CEI, CPM, TURN, and WGA all commented that the final system for accounting and verification should be a REC-based electronic accounting system. Powerex contended that they were not opposed to an electronic accounting system, though they indicated that if it focused solely on in-state generation, it could preclude out-of-state generators from competing fairly. They were supportive of a WECC-wide electronic accounting system.

Two parties, CEI and CPM, commented on the process for developing the details of the electronic accounting system. CEI stated that design of the details of the electronic accounting system requires an open stakeholder forum where participants feel empowered to work with the Energy Commission and CPUC. CPM noted that time is needed to reach general agreement on what a long-term system will look like. The Committee agrees with both of these comments, and commits to working expeditiously with all interested parties. A workshop regarding the details of the accounting system is planned as part of Phase 3 of the RPS proceeding.

Several comments were received that focused on the specific design of the system. CEERT suggested that "California's system be designed to ensure the following: 1) that a REC is only created when one unit of renewable energy is generated, 2) a REC is retired once it is used to meet the obligations of the RPS, and 3) a REC is treated in the

first instance as a property right of the generator, to be expressly identified and transferred via contract." SDG&E argued that the system should have an "open architecture that can accommodate future design and expansion. The electronic system should accommodate future enhancements such as a REC trading system." CPM also maintained that the system should be designed with future expansion in mind, and that "It should be simple, flexible, and automated." PG&E declared that the long-term system does not need to be designed to facilitate unbundling of environmental attributes or the trading of renewable energy credits and that there is no need to track or account for environmental attributes separately from the energy at this time.

The Committee agrees with the general principles of flexibility and an open architecture for the accounting system, and intends to rely on these principles during the design process.

Required Participants in the Accounting System

Decision: The Committee recommends that all of California's IOUs, ESPs, and CCAs that are subject to the RPS be required to participate in both the interim and final accounting system to verify their compliance with the law. Similarly, the Energy Commission will require all renewable generators who receive SEPs or sell their electricity or attributes to meet a retail seller's RPS obligations to participate in the system. Such generators must also fully opt-in to the system, meaning that all of the output from their facilities must be tracked by the electronic accounting system.

The Committee further recommends that the long-term system be designed to allow other parties to participate in the electronic accounting system, such as publicly owned utilities, brokers, or any other market participants who wish to verify renewable transactions or provide proof of renewable purchases.

If the Energy Commission ultimately decides that renewable electricity generated by customer-sited generators is eligible for the RPS, the Committee recommends developing a process to measure and verify the output from these generators. However, the Committee is deferring any decision regarding the eligibility of these renewable generators until Phase 3 of the RPS proceeding. The Committee invites further comment regarding the eligibility of customer-sited, grid-connected renewable generators as well as suggestions for how to measure and verify the output from these generators.

Discussion and Rationale: CEI and TURN commented that the accounting system should facilitate both mandatory and voluntary retail seller participation. The Committee agrees that all market participants should be included early to increase support for the system among retail sellers not currently under a mandate to participate. In addition, this approach will remove barriers to such retail sellers voluntarily meeting the RPS. As importantly, the broader the participation in the system, the more assurance can be provided that double counting is not occurring.

CPM commented that all output from out-of-state generators who are selling to retail sellers to meet the California RPS must be tracked in the California system to avoid double counting. The Committee agrees with this principle and extends it to all in-state generators as well. To meet the requirements of SB 1078 to ”ensure that renewable energy output is counted only once for the purpose of meeting the renewable portfolio standard of this state or any other state,” the state must know not only that a generator is selling its output to a California retail seller, but also to whom that power is sold.

It is conceivable that a California generator could be selling its renewable energy to meet another state’s RPS. Therefore, the long-term system must be designed so that other states may use it, and so it can track all of the output from any generation unit participating in the electronic accounting system to ensure that no double selling occurs. Tracking all of the output will also allow buyers of the renewable generation to verify that they are receiving all of the RECs they have paid for, even if they are purchasing the generation as part of a voluntary initiative.

Long-term System Source of Data

Decision: The Committee recommends that the electronic accounting system use settlements data on generation and wholesale transactions. The system should maintain an electronic database and accounting system with this information. If generation is not otherwise tracked through settlements data, but is still metered by local distribution companies, the generator or distribution company may self-report, provided that appropriate measures have been taken to ensure accuracy of the information.

The Committee invites comments on how the Energy Commission might verify the accuracy of self-reported power production data, including the accuracy of any independently owned metering equipment, and how to account for line losses for self-reported generation, if line loss calculations are required. The Committee believes that the accuracy of self-reported information may be verified or corroborated in some instances using reports and information from other agencies.

Discussion and Rationale: CPM stated in its comments that the “system should use accurate meter readings from generators, as collected by the ISO [Independent System Operator], as the basis for an electronic accounting system. There should be consistent treatment of energy and RECs in terms of loss factors (GMMs).” CPM also maintained that out-of-state generators that participate in the accounting system “must agree, through force of law, that all of their output will be tracked and verified through the California system to avoid double-counting.”

The Committee agrees with this assessment. The Committee recommends using settlement quality data for several reasons. First, the data can be adjusted for line losses if needed, therefore providing a consistent and accepted practice for handling line losses in an electronic accounting system even though settlements may not all be occurring at the California Independent System Operator. Second, financial settlement

data are universally accepted as the absolute measurement of generation and delivery of electricity, and provide an appropriate level of accuracy for an electronic accounting system.

CEI provided comments that customer-sited generation, whether or not grid-connected, should be able to participate in the system. IEP expressed concern in its comments about the credibility of self-reported generation. Other stakeholders at the workshop appeared more comfortable with engineering estimates and self-reported generation for customer-sited generation. Several stakeholders suggested that where possible, information from other agencies should be used to verify the accuracy of self-reported data. The Committee is deferring discussion regarding the participation of customer-sited generators for RPS purposes to Phase 3 of the RPS proceeding, and welcomes further comment on the parameters of such participation.

Transactions Tracked in the Electronic Accounting System

Decision: The Committee recommends that the electronic accounting system initially track only renewable generation — both RPS-eligible and any non RPS-eligible renewables that wish to participate in the accounting system — but that the system be flexible enough to accommodate future verification of specific purchases of non-renewable generation.

Discussion and Rationale: SB 1078 requires that the Energy Commission's accounting system not only serve RPS compliance purposes, but also be used for "verifying retail product claims in this state or any other state." The Committee interprets this language to mean that the accounting system, at a minimum, must also be used to verify compliance with the Energy Commission's Power Source Disclosure Program. However, the Committee envisions that retail sellers might make specific claims in the future regarding non-renewable purchases. Therefore, the electronic accounting system should be able to accommodate specific purchases of other types of generation.

In tracking non-renewable generation, there are essentially two types of electronic accounting systems: an open system and a closed loop system. An open system is usually voluntary and is only capable of tracking specific purchases and transactions specified by market participants. In contrast, a closed loop system tracks all generation attributes in a control area, has mandatory participation by all generators and market participants, and maintains a "conservation of attributes" by assigning attributes to non-specific power purchases.

The design of a closed loop system is also more complex and, in many ways, less flexible than the design of an open system. Many policy decisions are embedded in the design of a closed loop system, such as the NEPOOL GIS. Because of the mandatory nature of such a system, the Committee believes it would be difficult to get all the WECC states to agree on a single system design by early 2005. Based on the comments of the WGA, such a system also would not be compatible with the WGA effort.

The Committee agrees with comments that the electronic tracking system should be flexible and have an open architecture and recommends that the electronic accounting system be designed to track specific purchases only, not non-specific, system power purchases.

Type of Information Tracked by the Electronic Accounting System

Decision: The Committee recommends that each REC have an electronic record that contains a host of information about the generation attributes that would allow the Energy Commission and CPUC to determine that the REC qualifies for the RPS or other programs, where appropriate. RECs will be defined to be consistent with Decision 03-06-071, in collaboration with the Energy Commission. At this time, RECs remain fully aggregated, meaning that no individual sub-attributes, such as emissions benefits, may be traded separately from the REC. The Energy Commission may modify this recommendation in the future based on further examination of the issue in collaboration with the CPUC. In any case, the electronic accounting system will be tailored to meet the CPUC's ruling in Decision 03-06-071.

Discussion and Rationale: The electronic accounting system will track the following generation characteristics of each REC, recognizing that the system may be designed to track additional characteristics not mentioned here:

- generator name
- generator ID number(s)
- generator location - city, state
- commissioning date of generator
- installed capacity of generator (updated annually)
- date of generation (for each mWh)
- fuel type used (updated annually)
- whether the facility qualifies as "incremental" geothermal
- whether the facility is eligible for SEPs
- if the REC is from out-of-state, whether the associated energy was part of a contract that is eligible for RPS purposes

In addition, the electronic accounting system will receive information on the total load served from load schedulers and will note this in retail sellers' accounts.

Creating the designations of "SEP eligible" and "incremental geothermal" should not be construed as a decision that such designations are mutually exclusive. The Committee is currently evaluating specific information that geothermal generators will have to submit to demonstrate that their generation qualifies as incremental geothermal and under what conditions it would qualify for SEPs.

CEI suggested that data included in the long-term system should be able to be accessed separately for California use, particularly data that impacts eligibility for state program monies, and coded so data can be sorted in different ways for analysis later. The Committee agrees with this general principle. The Committee has identified a starting list of minimum attributes that will be tracked, but a more detailed discussion of what specific generation information is to be included will take place in the process of system design. CEI also argued that information on the labor characteristics of a plant should be included in the accounting system, as well as an indication of whether specific attributes have been monetized or not. The Committee welcomes further comment on these issues.

Public Access to Electronic System Data

Decision: The Committee recommends that the data collected for the electronic system be made available to the public, with the exception of data that falls into categories of data automatically designated confidential pursuant to the Energy Commission's regulations on confidentiality (Title 20, California Code of Regulations, sections 2501 et. seq). If the data do not belong to a category that is automatically confidential, the party that asks to have information kept confidential bears the burden of showing why it should not be disclosed.

Discussion and Rationale: CEI maintained that "Clear rules of access must be established and maintained regarding competitive access to data." The Committee agrees that information that is in a category automatically designated as confidential not be publicly accessible. For the remainder of the information, if a party wishes to have the data be confidential, the party bears the burden of showing that it should not be disclosed.

In-State Delivery Requirement

Decision: The Committee received several comments related to the delivery of electricity into California. The Committee recommends that the Energy Commission work with the California ISO to determine the ability to verify whatever in-state delivery requirements are ultimately imposed.

Discussion and Rationale: At the May 5, 2003 Committee Hearing, the Committee called for further discussion on whether a requirement to deliver power into California should be adopted and, if so, how such a requirement should be implemented. Powerex commented that RECs generated in British Columbia, Canada should be eligible for California's RPS, and was indifferent to the energy delivery requirement as long as it allows bundling of RECs generated by British Columbia generators with WECC spot market power delivered to California. CEI maintained that "sales of energy and credits may be bundled for convenience or on demand, but that the accounting must occur independently for each, as separate data streams for separate commodities." CPM argued that "Allowing RECs to be unbundled from the energy will facilitate broader retail seller compliance from ESPs and community aggregators." TURN commented in the

workshop that a delivery requirement is desirable to ensure that Californian's receive the air quality benefits of displacing in-state generation. Other workshop participants noted that in-state delivery is a common requirement among states with an RPS.

Participating in a WECC Accounting System

Decision: The Committee recommends that Energy Commission staff work with the WGA to develop a regional accounting system that can, at a minimum, exchange data with other states in the WECC to prevent double counting.

Discussion and Rationale: In June 2002, WGA passed a resolution that supports the "establishment of a single institution in the West that will issue, track, and oversee REC trading," and the "creation of an independent, regional generation accounting system to provide data necessary to substantiate the number of megawatt hours generated from renewable energy sources and support verification, accounting and trading of RECs" (Western Governors' Association Policy Resolution 03-03, February 25, 2003, page 5).

Since the passage of this resolution, two Working Group meetings — in which Energy Commission staff participated — have occurred to move forward on developing such a system. WGA has also contracted with the Center for Resource Solutions to construct a needs assessment survey to get input from key stakeholders. The survey would also identify the regulatory and commercial functions in the Western Interconnect that would be served by a certificates-based, western renewable energy generation information system. Once WGA receives the results from the needs assessment survey, WGA will develop the conceptual framework for such a system.

The majority of stakeholders at the May 13, 2003 workshop supported the idea of a regional accounting system, especially with respect to preventing double counting. Powerex, WGA, and the majority of workshop participants supported developing a WECC-wide electronic accounting system. Powerex commented that a WECC-wide accounting system would foster more competition for RECs, which would lower the costs of renewable energy as a whole and benefit California.

TURN expressed concern about the costs of a regional system versus one that serves California's needs. Workshop participants commented that existing electronic accounting systems are self-supporting through user fees. APX stated that the major costs of developing a WECC-wide electronic accounting system would be establishing a data interface with each of the settlement systems in the West. PG&E cautioned that California ratepayers should not bear any system costs beyond what is necessary to ensure RPS compliance and that it is inappropriate for California ratepayers to pay for systems needed by other states or by a private voluntary REC trading market. PG&E also agreed that the system should be self-supporting and supports the idea that each participating state could pay its own state's costs of developing a data interface with its settlement systems.

Determining "Baseline" Designation

Decision: The Committee recommends that if the CPUC, in collaboration with the Energy Commission, determines it is necessary to track whether a facility is "baseline" or "additional procurement," the electronic accounting system should add these designations in addition to the other designations of "SEP eligible" and "incremental geothermal."

Discussion and Rationale: The Committee received several comments in the workshop regarding whether the electronic system should identify that facilities are "baseline" or "additional procurement." At this time, it is not clear if the electronic accounting system will need to include a designation for "baseline" or "additional procurement." However, if the CPUC and Energy Commission ultimately decide this information is necessary, the accounting system will include a field associated with each generator that indicates whether the generator qualifies as a "baseline" or "additional procurement" facility.

If this designation is included, then any REC issued for a California generation facility would identify whether the REC is "baseline" or not. The designation would be input to the accounting system from the Energy Commission generator certification process and would be updated if a facility changed status.

Appendix A
PARTICIPANTS IN RPS PHASE 2 IMPLEMENTATION PROCEEDING

Agland Energy Services

Alliance for Retail Energy Markets

Bren School UC Santa Barbara

California Farm Bureau Federation

California Independent System Operator

California Wind Energy Association

Calpine Corporation

Center for Energy Efficiency and Renewable Technologies

Chateau Energy, Inc.

Clean Power Markets, Inc.

Heschong Mahone Group, Inc.

Independent Energy Producers Association

National Biodiesel Board

Natural Resources Defense Council

O'Connor Consulting Services, Inc.

Pacific Gas & Electric Company

Powerex Corp

PPM Energy

Renewable Energy, Inc.

San Diego Gas & Electric Company

Solargenix

T^2 and Associates

The Utility Reform Network

Theroux Environmental

Vulcan Power

World Water Corporation

Xenergy

Appendix B
RELEVANT STATUTORY LANGUAGE

Senate Bill 1078 (Sher, Statutes of 2002, Chapter 516)

Public Utilities Code
Article 16. California Renewables Portfolio Standard Program

399.11. The Legislature finds and declares all of the following:

(a) In order to attain a target of 20 percent renewable energy for the State of California and for the purposes of increasing the diversity, reliability, public health and environmental benefits of the energy mix, it is the intent of the Legislature that the California Public Utilities Commission and the State Energy Resources Conservation and Development Commission implement the California Renewables Portfolio Standard Program described in this article.

(b) Increasing California's reliance on renewable energy resources may promote stable electricity prices, protect public health, improve environmental quality, stimulate sustainable economic development, create new employment opportunities, and reduce reliance on imported fuels.

(c) The development of renewable energy resources may ameliorate air quality problems throughout the state and improve public health by reducing the burning of fossil fuels and the associated environmental impacts.

(d) The California Renewables Portfolio Standard Program is intended to complement the Renewable Energy Program administered by the State Energy Resources Conservation and Development Commission and established pursuant to Sections 383.5 and 445.

399.12. For purposes of this article, the following terms have the following meanings:

(a) "Eligible renewable energy resource" means an electric generating facility that is one of the following:

(1) The facility meets the definition of "in-state renewable electricity generation technology" in Section 383.5.

(2) A geothermal generation facility originally commencing operation prior to September 26, 1996, shall be eligible for purposes of adjusting a retail seller's baseline quantity of eligible renewable energy resources except for output certified as incremental geothermal production by the Energy Commission, provided that the incremental output was not sold to an electrical corporation under contract entered into prior to September 26, 1996. For each facility seeking certification, the Energy Commission shall determine historical production trends and establish criteria for measuring incremental geothermal production that recognizes the declining output of existing steamfields and the contribution of capital investments in the facility or wellfield.

(3) The output of a small hydroelectric generation facility of 30 megawatts or less procured or owned by an electrical corporation as of the date of enactment of this article shall be eligible only for purposes of establishing the baseline of an electrical corporation pursuant to paragraph (3) of subdivision (a) of Section 399.15. A new hydroelectric facility is not an eligible renewable energy resource if it will require a new or increased appropriation or diversion of water under Part 2 (commencing with Section 1200) of Division 2 of the Water Code.

(4) A facility engaged in the combustion of municipal solid waste shall not be considered an eligible renewable resource unless it is located in Stanislaus County and was operational prior

to September 26, 1996. Output from such facilities shall be eligible only for the purpose of adjusting a retail seller's baseline quantity of eligible renewable energy resources.

(b) "Retail seller" means an entity engaged in the retail sale of electricity to end-use customers, including any of the following:

(1) An electrical corporation, as defined in Section 218.

(2) A community choice aggregator. The commission shall institute a rulemaking to determine the manner in which a community choice aggregator will participate in the renewables portfolio standard subject to the same terms and conditions applicable to an electrical corporation.

(3) An electric service provider, as defined in Section 218.3 subject to the following conditions:

(A) An electric service provider shall be considered a retail seller under this article for sales to any customer acquiring service after January 1, 2003.

(B) An electric service provider shall be considered a retail seller under this article for sales to all its customers beginning on the earlier of January 1, 2006, or the date on which a contract between an electric service provider and a retail customer expires. Nothing on this subdivision may require an electric service provider to disclose the terms of the contract to the commission.

(C) The commission shall institute a rulemaking to determine the manner in which electric service providers will participate in the renewables portfolio standard. The electric service provider shall be subject to the same terms and conditions applicable to an electrical corporation pursuant to this article. Nothing in this paragraph shall impair a contract entered into between an electric service provider and a retail customer prior to the suspension of direct access by the commission pursuant to Section 80110 of the Water Code.

(4) "Retail seller" does not include any of the following:

(A) A corporation or person employing cogeneration technology or producing power consistent with subdivision (b) of Section 218.

(B) The Department of Water Resources acting in its capacity pursuant to Division 27 (commencing with Section 80000) of the Water Code.

(C) A local publicly owned electrical utility as defined in subdivision (d) of Section 9604.

(c) "Renewables portfolio standard" means the specified percentage of electricity generated by eligible renewable energy resources that a retail seller is required to procure pursuant to Sections 399.13 and 399.15.

399.13. The Energy Commission shall do all of the following:

(a) Certify eligible renewable energy resources that it determines meet the criteria described in subdivision (a) of Section 399.12.

(b) Design and implement an accounting system to verify compliance with the renewables portfolio standard by retail sellers, to ensure that renewable energy output is counted only once for the purpose of meeting the renewables portfolio standard of this state or any other state, and for verifying retail product claims in this state or any other state. In establishing the guidelines governing this system, the Energy Commission shall collect data from electricity market participants that it deems necessary to verify compliance of retail sellers, in accordance with the requirements of this article and the California Public Records Act (Chapter 3.5 (commencing with Section 6250) of Division 7 of Title 1 of the Government Code). In seeking data from electrical corporations, the Energy Commission shall request data from the commission. The commission shall collect data from electrical corporations and remit the data to the Energy Commission within 90 days of the request.

(c) Allocate and award supplemental energy payments pursuant to Section 383.5 to eligible renewable energy resources to cover above-market costs of renewable energy.

Senate Bill 1038 (Sher, Statutes of 2002, Chapter 515)

Public Utilities Code

383.5. (a) It is the intent of the Legislature in establishing this program, to increase the amount of renewable electricity generated per year, so that it equals at least 17 percent of the
total electricity generated for consumption in California.

(b) As used in this section, the following terms have the following meaning:

(1) "In-state renewable electricity generation technology" means a facility that meets all of the following criteria:

(A) The facility uses biomass, solar thermal, photovoltaic, wind, geothermal, fuel cells using renewable fuels, small hydroelectric generation of 30 megawatts or less, digester gas, municipal solid waste conversion, landfill gas, ocean wave, ocean thermal, or tidal current, and any additions or enhancements to the facility using that technology.

(B) The facility is located in the state or near the border of the state with the first point of connection to the Western Electricity Coordinating Council (WECC) transmission system located within this state.

(C) For the purposes of this subdivision, "solid waste conversion" means a technology that uses a noncombustion thermal process to convert solid waste to a clean burning fuel for the purpose of generating electricity, and that meets all of the following criteria:

(i) The technology does not use air or oxygen in the conversion process, except ambient air to maintain temperature control.

(ii) The technology produces no discharges of air contaminants or emissions, including greenhouse gases as defined in Section 42801 of the Health and Safety Code.

(iii) The technology produces no discharges to surface or groundwaters of the state.

(iv) The technology produces no hazardous wastes.

(v) To the maximum extent feasible, the technology removes all recyclable materials and marketable green waste compostable materials from the solid waste stream prior to the conversion process and the owner or operator of the facility certifies that the those materials will be recycled or composted.

(vi) The facility at which the technology is used is in compliance with all applicable laws, regulations, and ordinances.

(vii) The technology meets any other conditions established by the State Energy Resources Conservation and Development Commission.

(viii) The facility certifies that any local agency sending solid waste to the facility is in compliance with Division 30 (commencing with Section 40000) of the Public Resources Code, has reduced, recycled, or composted solid waste to the maximum extent feasible,
and shall have been found by the California Integrated Waste Management Board to have diverted at least 30 percent of all solid waste through source reduction, recycling and composting.

(d) (1) Fifty-one and one-half percent of the funds collected pursuant to paragraph (6) of subdivision (c) of Section 381, shall be used for programs designed to foster the development of new in-state renewable electricity generation technology facilities, and to secure for the state the environmental, economic, and reliability benefits that continued operation of those facilities will provide.

(2) Any funds used for new in-state renewable electricity generation technology facilities pursuant to this subdivision shall be expended in accordance with the report, subject to all of the

following requirements:

(A) In order to cover the above market costs of renewable resources as approved by the commission and selected by retail sellers to fulfill their obligations under Article 16 (commencing with Section 399.11), the Energy Commission shall award funds in the form of supplemental energy payments, subject to the following criteria:

(i) The Energy Commission may establish caps on supplemental energy payments. The caps shall be designed to provide for a viable energy market capable of achieving the goals of Article 16 (commencing with Section 399.11). The Energy Commission may waive application of the caps to accommodate a facility, if it is demonstrated to the satisfaction of the Energy Commission, that operation of the facility would provide substantial economic and environmental benefits to end use customers subject to the funding requirements of Section 381.

(ii) Supplemental energy payments shall be awarded only to facilities that are eligible for funding under this subdivision.

(iii) Supplemental energy payments awarded to facilities selected by an electrical corporation pursuant to Article 16 (commencing with Section 399.11) shall be paid for the lesser of 10 years, or the duration of the contract with the electrical corporation.

(iv) The Energy Commission shall reduce or terminate supplemental energy payments for projects that fail either to commence and maintain operations consistent with the contractual obligations to an electrical corporation, or that fail to meet eligibility requirements.

(v) Funds shall be managed in an equitable manner in order for retail sellers to meet their obligation under Article 16 (commencing with Section 399.11).

(B) The Energy Commission may determine as part of a solicitation, that a facility that does not meet the definition of "in-state renewable electricity generation technology" facility solely because it is located outside the state, is eligible for funding under this subdivision if it meets both of the following requirements:

(i) It is located so that it is or will be connected to the Western Electricity Coordinating Council (WECC) transmission system.

(ii) It is developed with guaranteed contracts to sell its generation to end use customers subject to the funding requirements of Section 381, or to marketers that provide this guarantee for resale of the generation, for a period of time at least equal to the amount of time it receives incentive payments under this subdivision.

(C) Facilities that are eligible to receive funding pursuant to this subdivision shall be registered in accordance with criteria developed by the Energy Commission and those facilities may not receive payments for any electricity produced that has any of the following characteristics:

(i) Is sold under an existing long-term contract with an existing in-state electrical corporation if the contract includes fixed energy or capacity payments, except for that electricity that satisfies the provisions of subparagraph (C) of paragraph (1) of subdivision (c) of Section 399.6.

(ii) Is used onsite or is sold to customers in a manner that excludes competitive transition charge payments, or is otherwise excluded from competitive transition charge payments.

(iii) Is produced by a facility that is owned by an electrical corporation or a local publicly owned electric utility as defined in subdivision (d) of Section 9604.

(iv) Is a hydroelectric generation project that will require a new or increased appropriation of water under Part 2 (commencing with Section 1200) of Division 2 of the Water Code.

(D) Eligibility to compete for funds or to receive funds shall be contingent upon having to sell the output of the renewable electricity generation facility to customers subject to the funding requirements of Section 381.

(E) The Energy Commission may require applicants competing for funding to post a forfeitable bid bond or other financial guaranty as an assurance of the applicant's intent to move forward expeditiously with the project proposed. The amount of any bid bond or financial

guaranty may not exceed 10 percent of the total amount of the funding requested by the applicant.

(F) In awarding funding, the Energy Commission may provide preference to projects that provide tangible demonstrable benefits to communities with a plurality of minority or low-income populations.

(3) Repowered existing facilities shall be eligible for funding under this subdivision if the capital investment to repower the existing facility equals at least 80 percent of the value of the repowered facility.

(4) Facilities engaging in the combustion of municipal solid waste or tires are not eligible for funding under this subdivision.

(5) Production incentives awarded under this subdivision prior to January 1, 2002, shall commence on the date that a project begins electricity production, provided that the project was operational prior to January 1, 2002, unless the Energy Commission finds that the project will not be operational prior to January 1, 2002, due to circumstances beyond the control of the developer. Upon making a finding that the project will not be operational due to circumstances beyond the control of the developer, the Energy Commission shall pay production incentives over a five-year period, commencing on the date of operation, provided that the date that a project begins electricity production may not extend beyond January 1, 2007.

(6) Facilities generating electricity from biomass energy shall be considered an in-state renewable electricity generation technology facility to the extent that they certify to the satisfaction of the Energy Commission that fuel utilization is limited to the following:

(A) Agricultural crops and agricultural wastes and residues.

(B) Solid waste materials such as waste pallets, crates, dunnage, manufacturing, and construction wood wastes, landscape or right-of-way tree trimmings, mill residues that are directly the result of the milling of lumber, and rangeland maintenance residues.

(C) Wood and wood wastes that meet all of the following requirements:

(i) Have been harvested pursuant to an approved timber harvest plan prepared in accordance with the Z'berg-Nejedly Forest Practice Act of 1973 (Ch. 8 (commencing with Sec. 4511), Pt. 2, Div. 4, P.R.C.).

(ii) Have been harvested for the purpose of forest fire fuel reduction or forest stand improvement.

(iii) Do not transport or cause the transportation of species known to harbor insect or disease nests outside zones of infestation or current quarantine zones, as identified by the Department of Food and Agriculture or the Department of Forestry and Fire Protection, unless approved by the Department of Food and Agriculture and the Department of Forestry and Fire Protection.

Assembly Bill 995 (Wright, Statutes of 2000, Chapter 1051) and Senate Bill 1194 (Sher, Statutes of 2000, Chapter 1050)

Public Utilities Code Section 399.6

399.6. (a) In order to optimize public investment and ensure that the most cost-effective and efficient investments in renewable resources are vigorously pursued, the Energy Commission shall create an investment plan as set forth in paragraphs (1) to (3), inclusive, to govern the allocation of funds provided pursuant to this article. The Energy Commission's long-term goal shall be a fully competitive and self-sustaining California renewable energy supply. The investment plan shall be in accordance with all of the following:

(1) The investment plan's objective shall be to increase, in the near term, the quantity of California's electricity generated by in-state renewable energy resources, while protecting system reliability, fostering resource diversity, and obtaining the greatest environmental benefits for California residents.

(2) An additional objective of the plan shall be to identify and support emerging renewable energy technologies that have the greatest near-term commercial promise and that merit targeted assistance.

(3) The investment plan shall contain specific numerical targets, reflecting the projected impact of the plan, for both of the following:

(A) Increased quantity of California electrical generation produced from emerging technologies and from overall renewable resources.

(B) Increased supply of renewable generation available from facilities other than those selling to investor-owned utilities under contracts entered into prior to 1996 under the federal Public Utilities Regulatory Policies Act of 1978 (P.L. 95-617).

(b) The Energy Commission shall, on an annual basis, evaluate progress on meeting the targets set forth in subparagraphs (A) and (B) of paragraph (3) of subdivision (a), or any substitute provisions adopted by the Legislature upon review of the investment plan, and assess the impact of the investment plan on reducing the cost to Californians of renewable energy generation.

(c) In preparing these investment plans, the Energy Commission shall recommend allocations among all of the following:

(1) (A) Except as provided in subparagraph (B), production incentives for new renewable energy, including repowered or refurbished renewable energy.

(B) Allocations may not be made for renewable energy that is generated by a project that remains under a power purchase contract with an electrical corporation originally entered into prior to September 24, 1996, whether amended or restated thereafter.

(C) Notwithstanding subparagraph (B), production incentives for incremental new, repowered or refurbished renewable energy from existing projects under a power purchase contract with an electrical corporation originally entered into prior to September 24, 1996, whether amended or restated thereafter, may be allowed in any month, if all of the following occur:

(i) The project's power purchase contract provides that all energy delivered and sold under the contract is paid at a price that does not exceed commission approved short-run avoided cost of energy.

(ii) Either of the following:

(I) The power purchase contract is amended to provide that the kilowatthours used to determine the capacity payment in any time-of-delivery period in any month under the contract shall be equal to the actual kilowatthour production, but no greater than the five-year average of the kilowatthours delivered for the corresponding time-of-delivery period and month, in the years 1994 to 1998, inclusive.

(II) If a project's installed capacity as of December 31, 1998, is less than 75 percent of the nameplate capacity as stated in the power purchase contract, the power purchase contract is amended to provide that the kilowatthours used to determine the capacity payment in any time-of-delivery period in any month under the contract shall be equal to the actual kilowatthour production, but no greater than the product of the five-year average of the kilowatthours delivered for the corresponding time-of-delivery period and month, in the years 1994 to 1998, inclusive, and the ratio of installed capacity as of December 31 of the previous year, but not to exceed contract nameplate capacity, to the installed capacity as of December 31, 1998.

(iii) The production incentive is payable only with respect to the kilowatthours delivered in a particular month that exceeds the corresponding five-year average calculated pursuant to clause (ii).

(2) Rebates, buydowns, or equivalent incentives for emerging renewable technologies.

(3) Customer credits for renewables not under contract with a utility.

(4) Customer education.

(5) Incentives for reducing fuel costs that are confirmed to the satisfaction of the Energy Commission at solid fuel biomass energy facilities in order to provide demonstrable environmental and public benefits, including but not limited to, air quality.

(6) Solar thermal generating resources that enhance the environmental value or reliability of the electricity system and that require financial assistance to remain economically viable, as determined by the Energy Commission. The Energy Commission may require financial disclosure from applicants for purposes of this paragraph.

(7) Specified fuel cell technologies, if the Energy Commission makes all of the following findings:

(A) The specified technologies have similar or better air pollutant characteristics than renewable technologies in the investment plan.

(B) The specified technologies require financial assistance to become commercially viable by reference to wholesale generation prices.

(C) The specified technologies could contribute significantly to the infrastructure development or other innovation required to meet the long-term objective of a self-sustaining, competitive supply of renewable energy.

(8) Existing wind-generating resources, if the Energy Commission finds that the existing wind-generating resources are a cost-effective source of reliability and environmental benefits compared with other eligible sources, and that the existing wind-generating resources require financial assistance to remain economically viable, as determined by the Energy Commission. The Energy Commission may require financial disclosure from applicants for the purposes of this paragraph.

(d) Commencing on January 1, 2002, public entities are not eligible to receive customer credits for renewables.

(e) Notwithstanding any other provision of law, moneys collected for renewable energy pursuant to this article shall be transferred to the Renewable Resource Trust Fund of the Energy Commission, to be held until further action by the Legislature. The Energy Commission shall prepare and submit to the Legislature, on or before March 31, 2001, an initial investment plan for these moneys, addressing the application of moneys collected between January 1, 2002, and January 1, 2007. The initial investment plan shall also include an evaluation of and report to the Legislature regarding the appropriateness and structure of a mandatory state purchase of renewable energy. On or before March 31, 2006, the Energy Commission shall prepare an investment plan proposing the application of moneys collected between January 1, 2007, and January 1, 2012. No moneys may be expended in the years covered by these plans without further legislative action.

Senate Bill 1305 (Sher, Statutes of 1997, Chapter 796)

Public Utilities Code
Article 14. Disclosure of Sources of Electrical Generation

398.1. (a) The Legislature finds and declares that there is a need for reliable, accurate, and timely information regarding fuel sources for electric generation offered for retail sale in California.

(b) The purpose of this article is to establish a program under which entities offering electric services in California disclose accurate, reliable, and simple to understand information on the sources of energy that are used to provide electric services.

398.2. The definitions set forth in this section shall govern the construction of this article.

(a) "System operator" means the Independent System Operator with responsibility for the efficient use and reliable operation of the transmission grid, as provided by Section 345, or a local publicly owned electric utility that does not utilize the Independent System Operator.

(b) "Specific purchases" means electricity transactions which are traceable to specific generation sources by any auditable contract trail or equivalent, such as a tradable commodity system, that provides commercial verification that the electricity source claimed has been sold once and only once to a retail consumer. Retail suppliers may rely on annual data to meet this requirement, rather than hour-by-hour matching of loads and resources.

(c) "Net system power" means the mix of electricity fuel source types established by the California Energy Resources Conservation and Development Commission representing the sources of electricity consumed in California that are not disclosed as specific purchases pursuant to Section 398.4.

398.3. (a) Beginning January 1, 1998, or as soon as practicable thereafter, each generator that provides meter data to a system operator shall report to the system operator electricity generated in kilowatthours by hour by generator, the fuel type or fuel types and fuel consumption by fuel type by month on an historical recorded quarterly basis. Facilities using only one fuel type may satisfy this requirement by reporting fuel type only. With regard to any facility using more than one fuel type, reports shall reflect the fuel consumed as a percentage of electricity generation.

(b) The California Energy Resources Conservation and Development Commission shall have authorization to access the electricity generation data in kilowatthours by hour for each facility that provides meter data to the system operator, and the fuel type or fuel types.

(c) With regard to out-of-state generation, the California Energy Resources Conservation and Development Commission shall have authorization to access the electricity generation data in kilowatthours by hour at the point at which out-of-state generation is metered, to the extent the information has been submitted to a system operator.

(d) Trade secrets as defined in subdivision (d) of Section 3426.1 of the Civil Code contained in the information provided to the system operators pursuant to this section shall be treated as confidential. These data may be disclosed only by the system operators and only by authorization of the generator except that the California Energy Resources Conservation and Development Commission shall have authorization to access these data, shall consider all these data to be trade secrets, and shall only release these data in an aggregated form such that trade secrets cannot be discerned.

398.4. (a) Every retail supplier that makes an offering to sell electricity that is consumed in California shall disclose its electricity sources. A retail supplier that does not make any claims that identify its electricity sources as different than net system power may disclose net system power. Every retail supplier that makes an offering to sell electricity that is consumed in California and makes any claims that identify any of its electricity sources as different than net system power shall disclose these sources as specific purchases.

(b) The disclosures required by this section shall be made to potential end-use consumers in all product-specific written promotional materials that are distributed to consumers by either printed or electronic means, except that advertisements and notices in general circulation media shall not be subject to this requirement.

(c) The disclosures required by this section shall be made at least quarterly to end-use consumers of the offered electricity.

(d) The disclosures required by this section shall be made separately for each offering made by the retail supplier.

(e) On or before January 1, 1998, the California Energy Resources Conservation and Development Commission shall specify guidelines for the format and means for disclosure required by Section 398.3 and this section, based on the requirements of this article and subject to public hearing.

(f) The costs of making the disclosures required by this section shall be considered to be generation-related.

(g) The disclosures required by this section shall be expressed as a percentage of annual sales derived from each of the following categories, unless no specific purchases are disclosed, in which case only the first category shall be disclosed:

(1) Net system power.

(2) Specific purchases.

(h) (1) Each of the categories specified in subdivision (g) shall be additionally identified as a percentage of annual sales that is derived from each fuel type of the categories specified as follows:

(A) Coal.

(B) Large hydroelectric (greater than 30 megawatts).

(C) Natural gas.

(D) Nuclear.

(E) Other.

(F) Eligible renewables, which means renewable resource technologies defined as electricity produced from other than a conventional power source within the meaning of Section 2805, provided that a power source utilizing more than 25 percent fossil fuel may not be included, shall be additionally identified as a percentage of annual sales that is derived from each fuel type of the subcategories specified as follows:

(i) Biomass and waste.

(ii) Geothermal.

(iii) Small hydroelectric (less than or equal to 30 megawatts).

(iv) Solar.

(v) Wind.

(2) The category "Other" shall be used for fuel types other than those listed above that represent less than 2 percent of net system power. The California Energy Resources Conservation and Development Commission may specify additional categories or change these categories, consistent with the requirements of this article and subject to public hearing, if it determines that the changes will facilitate the disclosure objectives of this section.

(i) All electricity sources disclosed as specific purchases shall meet the requirements of subdivision (b) of Section 398.2.

(j) Specific purchases identified pursuant to this section shall be from sources connected to the Western Systems Coordinating Council interconnected grid.

(k) Net system power shall be disclosed for the most recent calendar year available. Disclosure of net system power shall be accompanied by this qualifying note: "The State of California determines this net system power mix annually; your actual electricity purchases may vary." The California Energy Resources Conservation and Development Commission may

modify this note, consistent with the requirements of this article and subject to public hearing, if it determines that the changes will facilitate the disclosure objectives of this section.

(l) For each offering made by a retail supplier for which specific purchases are disclosed, the retail supplier shall disclose projected specific purchases for the current calendar year. Projected specific purchases need not be disclosed by numerical percentage at the subcategory level identified in subparagraph (F) of paragraph (1) of subdivision (h). On or before April 15, 1999, and annually thereafter, every retail supplier that discloses specific purchases shall also disclose to its customers, separately for each offering made by the retail supplier, its actual specific purchases for the previous calendar year consistent with information provided to the California Energy Resources Conservation and Development Commission pursuant to Section 398.5. Disclosure of projected specific purchases and actual specific purchases shall each be accompanied by statements identifying whether the data are projected or actual, as developed by the California Energy Resources Conservation and Development Commission, subject to public hearing.

(m) The provisions of this section shall not apply to generators providing electric service onsite, under an over-the-fence transaction as described in Section 218, or to an affiliate or affiliates, as defined in subdivision (a) of Section 372.

398.5. (a) Retail suppliers that disclose specific purchases pursuant to Section 398.4 shall report on March 1, 1999, and annually thereafter, to the California Energy Resources Conservation and Development Commission, for each electricity offering, for the previous calendar year each of the following:

(1) The kilowatthours purchased, by generator and fuel type during the previous calendar year, consistent with the meter data, including losses, reported to the system operator.

(2) For each electricity offering the kilowatthours sold at retail.

(3) For each electricity offering the disclosures made to consumers pursuant to Section 398.4.

(b) Information submitted to the California Energy Resources Conservation and Development Commission pursuant to this section that is a trade secret as defined in subdivision (d) of Section 3426.1 of the Civil Code shall not be released except in an aggregated form such that trade secrets cannot be discerned.

(c) On or before January 1, 1998, the California Energy Resources Conservation and Development Commission shall specify guidelines and standard formats, based on the requirements of this article and subject to public hearing, for the submittal of information pursuant to this article.

(d) In developing the rules and procedures specified in this section, the California Energy Resources Conservation and Development Commission shall seek to minimize the reporting burden and cost of reporting that it imposes on retail suppliers.

(e) On or before October 15, 1999, and annually thereafter, the California Energy Resources Conservation and Development Commission shall issue a report comparing information available pursuant to Section 398.3 with information submitted by retail suppliers pursuant to this section, and with information disclosed to consumers pursuant to Section 398.4. This report shall be forwarded to the California Public Utilities Commission.

(f) Beginning April 15, 1999, and annually thereafter, the California Energy Resources Conservation and Development Commission shall issue a report calculating net system power. The California Energy Resources Conservation and Development Commission will establish the generation mix for net generation imports delivered at interface points and metered by the system operators. The California Energy Resources Conservation and Development Commission shall issue an initial report calculating preliminary net system power for calendar year 1997 on or before January 1, 1998. This report shall be updated on or before October 15, 1998.

(g) The provisions of this section shall not apply to generators providing electric service on site, under an over-the-fence transaction as described in Section 218, or to an affiliate or affiliates, as defined in subdivision (a) of Section 372.

(h) The California Energy Resources Conservation and Development Commission may verify the veracity of environmental claims made by retail suppliers. In addition, the Energy Resources Conservation and Development Commission, in conjunction with the California Air Resources Board and affected air districts, shall issue a report to the Legislature by June 1, 1999, assessing the air emission effects of electric utility restructuring.

SEC. 4. No reimbursement is required by this act pursuant to Section 6 of Article XIIIB of the California Constitution because the only costs that may be incurred by a local agency or school district will be incurred because this act creates a new crime or infraction, eliminates a crime or infraction, or changes the penalty for a crime or infraction, within the meaning of Section 17556 of the Government Code, or changes the definition of a crime within the meaning of Section 6 of Article XIIIB of the California Constitution.

Notwithstanding Section 17580 of the Government Code, unless otherwise specified, the provisions of this act shall become operative on the same date that the act takes effect pursuant to the California Constitution.

Appendix C
GLOSSARY

Annual procurement target — the quantity of eligible renewable resources that a retail seller must procure within a particular year to reach the target of 20 percent of its retail sales procured from eligible energy resources no later than December 31, 2017.

Baseline — refers to the quantity of eligible renewable resources procured in 2001. For the baseline, "procurement" includes power sold to an investor owned utilities' customers by the Department of Water Resources and power from a facility owned or contracted for by the investor owned utility, pursuant to SB 1078 Section 399.15 (a) (3).

Biomass — any organic material not derived from fossil fuels, including agricultural crops, agricultural wastes and residues, waste pallets, crates, dunnage, manufacturing, and construction wood wastes, landscape and right-of-way tree trimmings, mill residues that result from milling lumber, rangeland maintenance residues, and wood and wood waste from timbering operations.

Capacity — the maximum amount of electricity that a generating unit, power facility, or utility can produce under specified conditions. Capacity is measured in kilowatts or megawatts.

Collaborative Staff — the staff at the Energy Commission and the California Public Utilities Commission who have been designated as having special status to work collaboratively and participate in confidential deliberations concerning decision-making on the implementation of the RPS.

Community choice aggregator— as defined in AB 117 (Migden, Chapter 838, Statutes of 2001-2002) refers to any of the following entities, if that entity is not within the jurisdiction of a local publicly owned electric utility that provided electrical service as of January 1, 2003: any city, county, or city and county whose governing board elects to combine the loads of its residents, businesses, and municipal facilities in a community-wide electricity buyers program or any group of cities, counties, or cities and counties whose governing boards have elected to combine the loads of their programs, through the formation of a joint powers agency established under Chapter 5 (commencing with Section 6500) of Division 7 of Title 1 of the Government Code.

Digester gas — gas from the anaerobic digestion of organic wastes.

Distributed generation — small scale electricity generation facilities sited in or close to a load center or at a customers' site.

Electric service provider — an entity such as a marketer or aggregator who provides electricity directly to an end-use customer in the direct-access market.

Electrical corporations — Pacific Gas and Electric Company, San Diego Gas and Electric Company, Southern California Edison Company, or other electrical corporations as defined by Public Utilities Code section 218, contributing funds to the Renewable Resource Trust Fund pursuant to Public Utilities Code section 381.

End-use customer (end-user) — a residential, commercial, agricultural, or industrial electric customer who buys electric power to be consumed as a final product (not for resale).

Fossil fuel — fuel comprised of hydrocarbon constituents, including coal, petroleum, or natural gas, occurring in and extracted from underground deposits, and mixtures or byproducts of these hydrocarbon constituents.

Fuel cell — an advanced energy conversion device that combines hydrogen-bearing fuels with air-borne oxygen in an electrochemical reaction to produce electricity very efficiently and with minimal environmental impact.

Geothermal — natural heat from within the earth, captured for production of electric power, space heating, or industrial steam.

Grid — the electrical transmission and distribution system linking power plants to customers through high power transmission line service.

Incremental geothermal – pursuant to PUC section 399.12 (a)(2), incremental geothermal refers to the electricity that can be produced from existing geothermal resource and is eligible to be counted toward an utility's required additional procurement rather than its baseline.

Hydroelectric — a technology that produces electricity by using falling water to turn a turbine generator, referred to as hydro. See also "small hydro."

Investor-owned utility (IOU) — synonymous with "electrical corporations" as defined herein.

Landfill gas (LFG) — gas produced by the breakdown of organic matter in a landfill (composed primarily of methane and carbon dioxide) or the technology that uses this gas to produce power.

Marketer — an agent for generation projects who markets power on behalf of the generator. The marketer may also arrange transmission, firming or other ancillary services as needed. Though a marketer may perform many of the same functions as a broker, a marketer represents the generator while a broker acts as a middleman.

Market price referent — refers to the cost of a non-renewable product used as a comparison to renewable products which are needed to satisfy a retail seller's RPS obligation pursuant to PUC section 399.15 (c). Further, pursuant to section 399.14 (f), procurement and administrative costs associated with long-term contracts entered into by an electrical corporation for eligible renewable resources, at or below the market price determined by the CPUC pursuant to subdivision (c) of section 399.15, shall be deemed reasonable per se, and shall be recoverable in rates.

Megawatt (MW) — one thousand kilowatts. One megawatt is about the amount of power to meet the peak demand of a large hotel.

Megawatt hour (mWh) — a unit of measure describing the amount of electricity consumed over time. It means one megawatt of electricity supplied for one hour. Two typical California households consume about a combined total of 1 mWh in an average month, one household consumes about 0.5 mWh.

Metered — the independent measurement with a standard meter of the electricity generated by a project or facility.

Municipal solid waste (MSW) — all solid, semi-solid, and liquid wastes, including garbage, trash, refuse, paper, rubbish, and demolition and construction wastes that can be processed and burned to produce energy.

Ocean wave — refers to an experimental technology that uses ocean waves to produce electricity.

Ocean thermal— refers to experimental technology that uses the temperature differences between deep and surface ocean water to produce electricity.

Photovoltaic (PV) — a technology that uses a semiconductor to convert sunlight directly into electricity.

Procurement — for the purposes of PUC section 399.14 (g), refers to a utility acquiring the renewable output of electric generation facilities that the utility owns or for which it has contracted.

Public Goods Charge (PGC) — a surcharge applied to the electric bills of IOU ratepayers used to support energy efficiency, public interest research, development and demonstration (RD&D), low income, and renewable energy programs. Also called *systems benefit charge*.

Renewable energy credits (RECs) —represents the separable bundle of non-energy or non-commodity attributes (environmental, economic, and social) associated with the generation of renewable electricity; the attributes of a given unit of renewable generation, separated from the underlying electrical energy. Green tag, green ticket, and tradable renewable certificate (TRC) are often used synonymously with REC.

Renewable — a power source other than a conventional power source within the meaning of Section 2805 of the Public Utilities Code, provided that a power source utilizing more than 25 percent fossil fuel is not included. Section 2805 states: " 'Conventional power source' means power derived from nuclear energy or the operation of a hydropower facility greater than 30 megawatts or the combustion of fossil fuels, unless cogeneration technology, as defined in Section 25134 of the Public Resources Code, is employed in the production of such power."

Renewables Portfolio Standard (RPS) — for the purposes of this document, the term refers to California's Renewables Portfolio Standard pursuant to SB 1078. In PUC section 399.12 (c) the law states that, "'renewables portfolio standard' means the specified percentage of electricity generated by eligible renewable energy resources that a retail seller is required to procure….". Under the RPS, an electrical corporation must increase its total procurement of eligible renewable energy resources by at least an additional 1 percent of retail sales per year so that 20 percent of its retail sales are procured from eligible energy resources no later than December 31, 2017.

Repower(ed) — generically refers to replacing a significant portion of the generating equipment at an existing facility.

RPS Collaborative Workplan — a written description of how the Energy Commission and the CPUC will work together to implement the RPS, including laying out a three-phased schedule to

categorize and sequentially address issues as appropriate. The designated collaborative staff of the Energy Commission and the CPUC developed the RPS Collaborative Workplan.

Small hydro — a facility employing one or more hydroelectric turbine generators, the sum capacity of which does not exceed 30 megawatts. Pursuant to PUC section 399.12, procurement from a small hydro facility as of January 1, 2003 is eligible only for purposes of establishing the baseline of an electrical corporation. A new small hydro facility is not eligible for the RPS if it will require a new or increased appropriation or diversion of water under Part 2 (commencing with Section 1200) of Division 2 of the Water Code. Pursuant to PUC section 383.5 (d) (2) (C) (iv), a new small hydro facility must not require an increased appropriation of water under Part 2 (commencing with Section 1200) of Division 2 of the Water Code to be eligible for supplemental energy payments.

Supplemental Energy Payments (SEP) — incentive payments from the Energy Commission to eligible renewable generators for the costs above the market referent of energy procured to meet the RPS, pursuant to PUC section 399.15 (a) (2). Any indirect costs from procuring eligible renewable resources – such as imbalance energy charges, sale of excess energy, decreased generation from existing resources, or transmission upgrades – are not eligible for SEP. The cost of the contract bids for renewable resources that are selected by the utilities to meet their RPS obligation will be compared to the cost of a comparable non-renewable product, the market price referent. Costs for renewable products that exceed the referent, excluding indirect costs noted above, will be covered by the SEP, subject to availability of Public Goods Charge (PGC) funds, pursuant to PUC section 399.15 (a) (4). The Energy Commission will distribute the SEP directly to the renewable generator through its New Renewable Facilities Program.

Tidal current power – energy obtained by using the motion of the tides to run water turbines that drive electric generators.

Transmission system — an interconnected group of electric transmission lines and associated equipment to move or transfer electric energy in bulk between points of supply and consumption.

Western Electricity Coordinating Council (WECC) — formed on April 18, 2002, by the merger of the Western Systems Coordinating Council (WSCC), Southwest Regional Transmission Association (SWRTA), and Western Regional Transmission Association (WRTA). WECC is responsible for coordinating and promoting electric system reliability, assuring open and non-discriminatory transmission access among members, and providing a forum for resolving transmission access disputes.

WECC interconnection — the junction where radial lines from a given power plant interconnect to the WECC-controlled transmission system.

Wind power— energy from wind converted into mechanical energy and then electricity.

Appendix D
ACRONYMS

AB	—	Assembly Bill
APX	—	Automated Power Exchange
AReM	—	Alliance of Retail Energy Markets
CalWEA	—	California Wind Energy Association
CCA	—	community choice aggregator
CEERT	—	Center for Energy Efficiency and Renewable Technologies
CEI	—	Chateau Energy, Inc.
CPM	—	Clean Power Markets
CPUC	—	California Public Utilities Commission
ESP	—	electric service provider
GMMs	—	generator meter multipliers
IEP	—	Independent Energy Producers
IOU	—	investor owned utility
ISO	—	Independent System Operator
kWh	—	kilowatt-hour
LFG	—	landfill gas
MSW	—	municipal solid waste
MW	—	megawatt
mWh	—	megawatt-hour
NRFP	—	New Renewable Facilities Program
PGC	—	Public Goods Charge
PPA	—	power purchase agreement
PUC	—	Public Utilities Code
PV	—	photovoltaic
REC	—	renewable energy credit
REI	—	Renewable Energy, Inc.
REP	—	Renewable Energy Program
RPS	—	Renewable Portfolio Standard
SB	—	Senate Bill
SEP	—	supplemental energy payments
TURN	—	The Utility Reform Network
WECC	—	Western Electricity Coordinating Council
WGA	—	Western Governors Association