Alliance for Retail Energy Markets Comments on RPS Issues for 2006 Integrated Energy Policy Report Update - RPS Mid-course Review

DOCKET
06-IEP-1 / 03-RPS-1078
DATE Jul 7-2006
RECD. Jul 7-2006

No. 06-IEP-1 and No. 03-RPS-1078

The Alliance for Retail Energy Markets (AReM) strongly supports the efforts of the Energy Commission to "simplify and streamline" the California RPS and respectfully submits the following comments in support of the 2006 Integrated Energy Policy Report Update - RPS Mid-course Review under docket numbers No. 06-IEP-1 and No. 03-RPS-1078.

AReM is a regulatory alliance of energy service providers (ESPs) that are active in California's retail electricity market. AReM members are committed to complying with the RPS in California and have been active participants in the process to develop an effective and workable RPS compliance program. ESPs intend to participate and comply with rules established by the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC). It is AReM's goal to seek clear and simple rules for compliance that help achieve the policy goals of the state while recognizing the unique aspects of the role that ESPs play within the electric industry in California.

If past performance is an indication of how ESPs would perform in California, then one only need look to the other states with RPS policies where ESPs are successfully complying with RPS targets. Outside of California, nineteen states and the District of Columbia have RPS policies and eleven states have competitive suppliers. In each case, ESPs have complied or will comply with the local RPS rules as directed. As an overarching comment, ESPs support a simpler, more transparent RPS process in order to achieve the state's 2010 goals. Details to support this comment are described herein as responses to questions posed by the Energy Commission for this workshop.

What further actions are needed to ensure that publicly owned utilities, ESPs, and CCAs meet the same targets, timelines, and eligibility standards as IOUs, and what type of exemption process is needed to avoid overly burdensome requirements for smaller entities?

ESPs are committed to complying with the RPS in California.[1] However, the current California compliance scheme is far too complex and uncertain for the ESPs to make useful operational and business decisions for compliance purposes. To date, no final rules for ESP compliance have been decided at the CPUC and Rulemaking 06-02-012 was opened in February to address a number of outstanding RPS implementation issues including many of those discussed in this workshop.

> "These include the manner in which electric service providers (ESPs), community choice aggregators (CCAs), small utilities, and multi-jurisdictional utilities will participate in the RPS program, based on the principles enunciated in D.05-11-025; and the potential for use of unbundled and/or tradable renewable energy credits (RECs) for compliance with RPS requirements, including the characteristics or attributes of any RECs allowed for RPS compliance and the status of RECs associated with renewable energy generated by qualifying facilities (QFs) and utility-funded distributed generation."[2]

Under the first RPS implementation Rulemaking (R.04-04-026), the ESPs submitted to the CPUC a detailed, yet simpler, compliance plan suggesting specific action to meet the RPS targets. A copy of the compliance plan AReM submitted to the CPUC is included as Appendix A and key components of the plan include the following:

1. <u>Meeting the Energy Action Plan's Goal of 20% Renewables By 2010</u>: AReM supports this overarching goal of the RPS and intends to fulfill the requirements set forth under this policy.

2. <u>Compliance with the Requirement to Increase Procurement of Renewables By at Least l% of Annual Retail Sales per Year</u>: AReM recommends that, as with the IOUs, ESPs will be required to increase procurement of renewables by at least 1%

[1] AReM does not address herein RPS compliance issues regarding publicly owned utilities or CCAs or what type of exemption process is needed to avoid overly burdensome requirements for smaller entities.
[2] Order Instituting Rulemaking to Develop Additional Methods to Implement the California Renewables Portfolio Standard Program, Public Utilities Commission, February 16, 2006, Rulemaking 06-02-012.

of annual retail sales per year. AReM also recommends that the first year for ESP compliance should be 2006, since there were rules in place to govern compliance, there was no rational manner for ESPs to comply with the RPS in years prior to 2006. Finally, in an effort to establish a fair and equitable RPS compliance process for competitive entities like ESPs, AReM offers that all ESPs' baseline should be the same in 2006 regardless of the actual amount of renewable sales currently in their portfolio.

3. Reporting Requirements: AReM proposed a relatively simple process for how to report progress toward the RPS for the year 2006. This proposal will likely need to be modified for the post-2006 period as the Western Renewable Energy Generation Information System ("WREGIS") becomes operational. The AReM reporting proposal is summarized below and the rationale for each recommendation can be found in the compliance proposal filed with the CPUC.

    a. *Number and Timing of Reports:* ESPs shall report once annually on compliance for the previous calendar year on May 1st of the following year.

    b. *Report Format:* AReM proposes that ESPs should use the Green Power Institute's proposed template attached to D.05-07-039 as Appendix A to summarize their RPS compliance for the previous year. This template is clear and concise and reports total retail sales, renewable procurement by resource type, and balance (carry forward or deficit). This form is included in Appendix A as Attachment 2. It would need to be updated if a single RPS target is established.

    c. *Verification:* In addition to the summary reporting form described above, ESPs would also have to provide an attestation by an officer of the ESP that, to the best of his or her knowledge, the summary statement on the template is true and accurate and that the renewable resources were sold once and only once. An example of such an attestation form is attached to this filing in Appendix A, Attachment 3. In order for the CPUC to verify

the validity of the renewable resources claimed in the summary report, and attested to by the ESP's officer, ESPs would be required to obtain and maintain on file signed attestations from renewable resource sellers that include:

i. Identification and Registration of renewable power plant sources to determine where and what the sources are;

ii. Declaration of the quantity sold and dates sold for either RECs or bundled renewable power;

iii. Declaration from the seller that they were "sold once, and only once" along with all renewable and emissions attributes and were not claimed by another entity to meet other requirements.

AReM recommends that, as a general rule, access to the confidential ESP data submittals, and any supporting confidential information, should be limited to CPUC and Energy Commission staff that are directly involved in the verification and enforcement of ESP compliance with the RPS.

4. Flexible Compliance Mechanisms: AReM provided detailed recommendations on flexible compliance mechanisms that will both increase the ESPs' ability to comply with and simplify the process for achieving the RPS targets. Again, specific details are in AReM's compliance plan and a summary of the key mechanisms are highlighted below.

   a. *Forward Banking:* The CPUC has already determined in D.05-11-025 that ESPs should be allowed to bank excess procurement without limitation for the same reasons that it makes sense for IOUs, and AReM agrees with this conclusion.[3]

[3] Section 399.14 (a)(2)(C).

b. *Backward Banking:* The CPUC has already determined in D.05-11-025 that ESPs should be allowed to use backward banking in the same manner as the IOUs, and AReM agrees with this conclusion.[4]

c. *Short-term Contracts:* AReM proposes that contracts of any length, including short-term, be allowed to count towards RPS compliance for ESPs and has testified to this point during recent evidentiary hearings at the CPUC. AReM recognizes this issue is being addressed by the CPUC at present and intends to continue to participate in the development of this mechanism through the formal CPUC process.

d. *Unbundled Renewable Energy Credits (RECs):* AReM proposes that ESPs be allowed to use unbundled RECs as part of a toolkit of flexible compliance mechanisms in order to facilitate compliance with the RPS. AReM will discuss the basis for this recommendation further below.

5. Penalties and Enforcement Procedures: AReM proposed a penalty procedure for ESPs that is described in detail in the compliance plan. Should a penalty be assessed to an ESP, AReM proposed that the CPUC adopt the same five cent per kWh penalty adopted in D.03-06-071 as the standard penalty for ESPs, with an upper limit of $2.5 million per year per ESP to reflect the smaller size of ESPs. As with the IOUs, however, the Commission should accord due process rights to any LSE for which non-compliance has been alleged and take mitigating factors into consideration when setting the actual penalty amount.

6. DA Customers Pay the Public Goods Charge and Must Meet the RPS Requirements. Therefore, They Should Have Access to Supplemental Energy Payments: While AReM did not make a specific proposal for how SEPs should be applied to ESPs, AReM did request that "the Commission [CPUC] affirm the basic principle that DA customers have an equal right to protection from the

[4] D.05-11-12. Conclusion of Law 1, p. 24.

potential of above-market costs associated with RPS compliance." A discussion of the Market Price Referent and SEPs is provided below.

As AReM's compliance proposal indicates, ESPs are committed to compliance with the RPS and have provided numerous suggestions as to how ESP compliance, and a step toward meeting the RPS targets, can be achieved in a simple and straightforward manner.

The desirability of establishing a single RPS target reflecting the total amount of renewable generation needed each year to meet the 2010 RPS goals.

AReM supports a single RPS target for all LSEs in California. As stated in the scope of this workshop, California currently has only enough renewable resources to reach 11% of the RPS target. As such, a significant increase in new renewables is required to ensure LSEs can meet the 20% in 2010 target. To reach that aggressive goal, we will need all the existing renewables as well. The original concern that justified the separation of baseline and incremental renewables was that LSEs could simply rely on the existing renewables to meet their targets and no new renewables would be built. Now we have a situation where there is no way that the goal can be achieved without significant new renewables being built. California regulators will only waste valuable resources monitoring the minutia of baseline versus incremental resources when, at a minimum, existing resources will need to be maintained and then an equal amount of new renewables will have to be created in addition to achieve the RPS targets by 2010.

As such, AReM recommends that there should be no distinction with regard to baseline versus incremental resources and that all resources should be included in a single RPS target for all LSEs. This recommendation would also apply to the following two workshop questions.

a. ***Whether statutory requirements that generation from specific geothermal, small hydro, and municipal solid waste combustion facilities apply only to the baseline are still necessary, and whether those restrictions would hamper movement to a single RPS target.***

For the reasons described above, AReM believes that maintaining these requirements for specific baseline-only resources would overly and unnecessarily complicate a move to a clear, single RPS target.

b. Whether statutory requirements applying to incremental geothermal should be removed.

For the reasons described above, AReM believes that maintaining these requirements for incremental geothermal would overly and unnecessarily complicate a move to a clear, single RPS target.

How to implement the 2005 Energy Report recommendation to explore limited use of renewable energy certificates for RPS compliance to facilitate uniform participation by all load serving entities.

AReM supports the eventual incorporation of a fully tradable, unbundled renewable energy certificates market as a flexible compliance mechanism for meeting the RPS targets for several important reasons. First, AReM believes that the use of such RECs facilitates cost-effective compliance for LSEs by allowing for a larger pool of resource from which to purchases RECs and reduced transaction costs. RECs also serve to lessen some of the transmission constraint issues California is struggling with today. While RECs will not completely resolve these issues, they do afford more flexibility for LSEs to comply without having to schedule the bundled renewable energy into distant territories. RECs also provide an additional value-stream for a renewable developer that is not currently available with California's bundled product requirements. Finally, RECs can represent a consistent "currency" for all parties involved in RPS compliance in California and would simplify the compliance process and reduce uncertainty in the market.

It is important to note that RECs are essentially an accounting mechanism for renewable energy production and the use of RECs does not prejudge other key issues such as eligible technologies or geographical applicability. Establishing a REC-based compliance mechanism would simplify the accounting and tracking under the California RPS but using RECs would not obviate the need for additional decisions on out-of-state

resources, eligible resources or SEP payments. Each of these issues would require additional decisions and RECs would simply be a method of accounting.

To that end, AReM stresses that a REC-based system initiated with unbundled RECs would greatly enhance LSEs' ability to meet the 2010 PRS targets. While still under development, once WREGIS is operational (expected 2007), it will provide for sufficient tracking and accounting to implement an efficient REC-based system that could allow for tradable REC products. In the interim a contract-path accounting system could be used for unbundled RECs and allow limited trades among parties in California. Precedent for this would be the Energy Commission's Customer Credit Subaccount Tracking.

Most states with RPS policies today currently allow or require the use of tradable, unbundled RECs to determine compliance since RECs are viewed a tool to simplify the compliance process. At present, given that California is evaluating ways to simplify the RPS, it would be beneficial to look at the approaches for using RECs in other states. AReM conducted research on the use of RECs in other states and its results demonstrate that RECs allow for a simplified process while still ensuring new renewable generation occurs. A copy of the Ecos report is provided as Appendix B.[5] Outside of California, the District of Columbia and seventeen of the nineteen states that have RPS policies employ some form of RECs for compliance. Indeed, California is the only state that has competitive suppliers that does not allow for the use of RECs. As such, AReM fully supports the move to a tradable, unbundled REC-based system in California to not only simplify the process but reap the benefits discussed herein.

Regarding ESPs and CCAs, should the MPR and SEP processes be applied, and, if so, how should these be applied for contract terms of less than 10 years?

The Energy Commission should recognize that direct access customers pay into the SEP account at the same levels as the IOUs' bundled customers. Accordingly, the price protection for RPS compliance afforded by SEPs should apply equally for direct access customers and bundled service customers.

[5] This Appendix is provided at the request of the Energy Commission during the July 6, 2006 workshop.

As designed, the MPR/SEP structure was specifically designed for use with a regulated procurement process such as that conducted by the IOUs. One feature of that process is that the CPUC has required IOUs to offer only long-term contracts of greater than 10 years. Consequently the MPR process calculates MPRs on a 10-, 15- and 20-year basis However, AReM firmly believes that the MPR calculations can easily be expanded to reflect shorter-term contract lengths that would more accurately reflect what constitutes "above market" costs for these types of products. Therefore, MPR calculations for shorter term contracts can be added to the 10- 15- and 20-year MPRs. This would allow LSEs which follow the other aspects of the MPR/SEPs process to have the flexibility to sign shorter term contracts for new renewables as well as provide another financing path to renewable developers if they preferred a shorter contract.

While AReM believes the MPR/SEP process could easily be adjusted to reflect shorter term contracts, this MPR/SEPs construct is difficult to apply to a REC-based system. If a REC-based system, as discussed above, is introduced in California, AReM offers two potential approaches for managing above market price risks under this system.

1. Alternative Compliance Payments (ACPs): Six states with RPS policies currently employ ACPs as a cost mitigation measure. With this approach, if the cost of a compliance REC exceeds a pre-specified level (e.g. $50/MWh), then LSEs can pay an ACP in lieu of purchasing a REC. In most cases, the ACPs are paid into a fund which is used to support bringing new renewable generation online.

2. Reverse-Auction for Renewable Above-Market Payments: The Energy Commission previously administered a successful program under the New Renewables Account Program. Under this system, any above-market price payments are made to generators based on a competitively-bid reverse auction process, where the generators requiring the lowest project subsidies are first in line to receive payments. This system decouples above-market costs from the underlying energy and REC products and helps to ensure that the most cost-competitive projects are built.

In conclusion, AReM is committed to meeting the RPS targets but believes that the current RPS process is far too complex. It is important to simplify the process for all LSEs to achieve the targets and AReM commends the Energy Commission's efforts to this end. As stated in the workshop and these comments, AReM submitted a detailed compliance plan to the CPUC in February and one major step to assuring ESP compliance in 2006 would be for the recommendations in this plan to be adopted. Finally, AReM strongly urges the Energy Commission to facilitate the introduction of RECs in California as a basic accounting mechanism to allow for more efficient renewable procurement for all LSEs.

Respectfully submitted,

Richard Counihan
ECOS CONSULTING
274 Brannan Street, Suite 600
San Francisco, CA 94107
(415) 371-0604
rcounihan@ecosconsulting.com

On behalf of
ALLIANCE FOR RETAIL ENERGY MARKETS

Date: July 7, 2006

Appendix A: AReM Compliance Proposal

Appendix B: Evaluating CA RECs

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement the California Renewables Portfolio Standard Program.	Rulemaking 04-04-026 (Filed April 22, 2004)

PROPOSAL OF THE ALLIANCE FOR RETAIL ENERGY MARKETS FOR THE PARTICIPATION OF ELECTRIC SERVICE PROVIDERS IN THE RENEWABLES PORTFOLIO STANDARD PROGRAM UNDER THE FRAMEWORK ESTABLISHED IN DECISION 05-11-025

Rick Counihan
Managing Director-California
ECOS CONSULTING
274 Brannan Street, Suite 600
San Francisco California 94107
Telephone: (415) 371-0604
Email: rcounihan@ecosconsulting.com

On behalf of
Alliance for Retail Energy Markets

Daniel W. Douglass
Gregory S. G. Klatt
DOUGLASS & LIDDELL
21700 Oxnard Street, Suite 1030
Woodland Hills, California 91367-8102
Telephone: (818) 593-3939
Facsimile: (818) 593-3911
Email: douglass@energyattorney.com

Attorneys for
Alliance for Retail Energy Markets

Date: February 17, 2006

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement the California Renewables Portfolio Standard Program.	Rulemaking 04-04-026 (Filed April 22, 2004)

PROPOSAL OF THE ALLIANCE FOR RETAIL ENERGY MARKETS FOR THE PARTICIPATION OF ELECTRIC SERVICE PROVIDERS IN THE RENEWABLES PORTFOLIO STANDARD PROGRAM UNDER THE FRAMEWORK ESTABLISHED IN DECISION 05-11-025

Pursuant to Administrative Law Judge ("ALJ") Anne E. Simon's ruling of January 3, 2006,[1] and in accordance with the procedural schedule set forth in ALJ Simon's ruling of February 3, 2006,[2] the Alliance for Retail Energy Markets ("AReM") respectfully submits this proposal for the participation of electric service providers ("ESPs") in the Renewables Portfolio Standard ("RPS") program.[3]

I. INTRODUCTION

In Decision ("D.") 05-11-025, the Commission determined the basic parameters for the participation of ESPs, community choice aggregators ("CCAs"), small utilities and multi-jurisdictional utilities in the RPS program.[4] Pursuant to D.05-11-025, the aforesaid load-serving entities ("LSEs") are required to comply with, or otherwise are subject to, five fundamental aspects of the RPS program:

---

[1] R.04-04-026, ALJ's Ruling Setting Schedule for Submission of Proposals for RPS Participation (Jan. 3, 2006).

[2] R.04-04-026, ALJ's Ruling Extending Time to File Proposals for RPS Participation (Feb. 3, 2006), p. 2.

[3] AReM is a California mutual benefit corporation whose members are electric service providers that are active in California's direct access market. The positions taken in this filing represent the views of AReM but not necessarily those of any individual member of AReM or the affiliates of its members with respect to the issues addressed herein.

[4] D.05-11-025, *mimeo*, p. 1.

1. The requirement that 20% of retail sales come from renewable sources by 2010, as required by the Energy Action Plan;
2. The requirement to increase renewable retail electricity sales by at least 1% per year until the 20% requirement is met;
3. The requirement to report progress toward meeting RPS requirements to the Commission;
4. The ability to utilize flexible compliance mechanisms; and
5. Being subject to penalties and penalty processes.[5]

This filing presents AReM's proposal for how these fundamental aspects of the RPS program should be applied to ESPs.[6] As directed by ALJ Simon, AReM first describes the requirements and standards applicable to the investor-owned utilities ("IOUs") in each of these five areas before presenting AReM's proposal with respect to ESPs. In addition, AReM explains its rationale for any differing treatment that it recommends be accorded to ESPs.

II. BASIC PRINCIPLES

As the Commission recognized in D. 05-11-025, the paramount goal of the RPS program is for all LSEs to provide 20% of their retail sales from renewable resources by the year 2010. The Commission has also recognized that the continued viability of direct access ("DA") is critical to California's energy future.[7] To ensure that neither of these objectives is sacrificed at

---

[5] *See* D.05-11-02, pp. 10-11, 14; and Ordering Paragraph No. 1.

[6] AReM attended the RPS Reporting and Compliance Workshop held on February 16, 2006. AReM has not had sufficient time to fully consider and address the issues relevant to ESPs that were raised during the Workshop or in the "RPS Annual Procurement Targets Reporting and Compliance Staff White Paper" that was presented and discussed during the Workshop. However, it is AReM's understanding that formal post-workshop comments and reply comments will be allowed. AReM will fully address issues related to RPS reporting and compliance in said comments at the appropriate time.

[7] D.03-07-030, *mimeo*, p. 23.

the expense of the other, AReM's proposal for ESP participation in the RPS program is based on certain basic principles. Those principles are:

- Maximize the probability of ESPs achieving 20% renewables by 2010;
- Requirements for ESPs should be clear and simple;
- An ESP's compliance with the RPS should be easy for the Commission to track and verify;
- Requirements for ESPs should be competitively neutral between ESPs;
- DA customers should have equitable access to Supplemental Energy Payments ("SEPs") to cover any above-market costs of compliance incurred by their ESPs; and
- Requirements for ESPs should account for the unique status of such entities and the different regulatory framework under which they operate.

While these principles are largely self-explanatory, the last two require some further elaboration.

Currently, the direct access market in California is limited to customers who were receiving direct access as of September 20, 2001. ESPs cannot compete with the IOUs for service to bundled customers. However, they can, and do, compete with each other for the existing DA load. For example, when a current DA customer completes its current DA agreement it can then seek new DA offers. In such a situation, ESPs bid against each other to provide future service to the DA customer. Because of this, it is important that the adopted RPS compliance standards be competitively neutral among ESPs.

Like the IOUs' bundled customers, DA customers also pay the public goods charge ("PGC") that supports the renewable energy public goods programs at the California Energy Commission ("CEC"). The PGC also funds the SEPs that are intended to cover the above-

market costs of complying with the RPS.[8] Therefore, DA customers, like bundled customers, should reap the benefits that result from their PGC payments by having the above-market costs associated with their suppliers' RPS compliance be made eligible for equitable access to SEPs.

AReM has identified the differences between the regulatory framework that ESPs operate under, and those that IOUs operate under, in previous filings leading up to D.05-11-025. A summary table of those differences is provided as Attachment 1 to this filing. AReM will elaborate further on the significance of those differences as they relate to ESP participation in specific aspects of the RPS program. For now, the main point to keep in mind is that the Commission has already determined that, due to the differences in the regulatory frameworks and market conditions under which ESPs and the IOUs operate, a "one-size-fits-all" approach to implementing the RPS program is neither practicable, nor reasonable, nor desirable from a public policy perspective.[9] Indeed, the Commission is not alone in this assessment. A recent report to the CEC on the prospects for achieving a 33 percent RPS requirement stated:

> The overall RPS design in California (as defined by statute and subsequent regulations), with renewable energy procurement plans, advance approval of bid solicitations, PRG review of contracts, and CPUC contract approval, may simply not make sense for ESPs and CCAs, and if applied to ESPs and CCAs, would impose substantial regulatory burdens on the CPUC.[10]

---

[8] Section 399.15 (a) (2).

[9] *See* D.05-11-025, p. 12:

> ESPs and CCAs each are subject to separate and distinct legal and regulatory requirements. Although they are each subject to certain requirements of this Commission as assigned by the Legislature, neither is regulated as a "public utility" as defined by the Public Utilities Code, nor are they subject to Commission regulatory authority as a matter of course. Instead, the Commission is granted specific regulatory authority over these entities for particular issues, in this case, RPS. Because of this, each of these entities in existence or planned operates under a business model that is different from a regulated public utility.

[10] Hamrin, J., R. Dracker, J. Martin, R. Wiser, K. Porter, D. Clement, M. Bolinger, *Achieving A 33% Renewable Energy Target* (Nov. 1, 2005), p. 121.

III. PROPOSED RULES, POLICIES AND PROCEDURES

A. Meeting the Energy Action Plan's Goal of 20% Renewables By 2010

The RPS statute provides that the IOUs are required to increase their procurement of renewables to 20% of their retail sales by 2017.[11] In the Energy Action Plan, the CEC recommended that the target date of 2017 for 20% renewables be accelerated to 2010. The Commission subsequently adopted this accelerated target date for the IOUs and determined in D.05-11-25 that the same target date should apply to all LSEs, including ESPs.[12] As this is the overarching goal of the entire RPS program, the Commission should consider all other RPS-related requirements to be subordinate. The Commission should therefore reject any proposed requirement for ESPs that could act as an obstacle to their timely attainment of 20% renewables by 2010. Moreover, the Commission can take steps to help ESPs achieve this goal by allowing the use of flexible compliance tools as described below.

B. Compliance with the Requirement to Increase Procurement of Renewables By at Least l% of Annual Retail Sales Per Year

The RPS statute provides that the IOUs are required to increase their procurement of renewable resources by at least 1% of sales per year starting in 2003 as measured against the baseline year of 2001.[13] In D.03-06-071, the Commission determined that it would require the IOUs to meet but not exceed this minimum requirement. The Commission should adopt the same rule for ESPs, i.e., they will be required to increase their renewable procurement by 1% per year. In connection with this requirement, the Commission must address three crucial items:

- How much should the annual increase be for ESPs?
- When should ESP compliance start?

---

[11] Section 399.15(b)(1).

[12] D.05-11-025, p. 11.

[13] Sections 399.15(a)(3) and 399.15(b)(1).

- What should be the baseline from which to start measuring annual increases for ESPs?

1. How much should the annual increase be for ESPs?

IOU Requirement: Increase of 1 percent per year.[14]

Proposed ESP Requirement: The minimum annual increase for ESPs should be the same as for IOUs—1 percent per year.

2. When should ESP compliance start?

IOU Requirement: First year of compliance was 2003.

Proposed ESP Requirement: The first year of ESP compliance should be 2006 and there should be no compliance requirement for prior years. This is different from the IOUs in that the IOUs had 2003 set as their first year of compliance by statute.[15]

Rationale for Difference: From a legal perspective, the Commission had no choice but to make 2003 the first year of compliance for IOUs because of the following section of Public Utilities Code 399:

> (b) The commission shall implement annual procurement targets for each *electrical corporation* (emphasis added) as follows:
>
> (1) Beginning on January 1, 2003, each *electrical corporation* (emphasis added) shall, pursuant to subdivision (a), 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 renewable energy resources no later than December 31, 2017. An electrical corporation with 20 percent of retail sales procured from eligible renewable energy resources in any year shall not be required to increase its procurement of such resources in the following year.

[14] D.03-06-071, p. 73, Ordering Paragraph 19.

[15] Section 399.15(b)(1).

Section 399.15 (b) (1) above applies to electrical corporations, a designation that includes IOUs but does not include ESPs. The Commission therefore has the option to set a different date for the first year of compliance for ESPs and it should choose a different date for fairness reasons.

D.03-06-071 was approved by the Commission on June 19, 2003, giving the IOUs only half a year to procure sufficient renewables to comply with their 2003 requirement. Now a very analogous situation is going to happen to the ESPs. The specific details of how ESPs should comply with the RPS will be decided in this proceeding and that decision will probably not come out until the middle of 2006, putting ESPs in the same position IOUs experienced in 2003—i.e., they only have half a year to comply with their first year requirement.

Without rules in place to govern compliance, there is no way that ESPs could have complied with the RPS in years prior to 2006. Similarly, it would be unfair to the ESPs to have retroactive requirements placed on them. Finally, the adoption of retroactive compliance goals for years prior to 2006 is pointless since it will only punish or reward behavior that has already taken place in the absence of rules for compliance and will not provide incentive or direction towards meeting the overarching goal of 20 percent by 2010. The Commission should start from today and put in place rules that maximize the probability of achieving 20 percent by 2010.

3. What is the baseline from which to start measuring annual increases?

IOU Requirement: Percentage of retail sales from renewable energy resources in 2003.

Proposed ESP Requirement: The baseline from which to start measuring annual increases should be zero for all ESPs, regardless of their actual percentage of renewable resources in previous years. This is different from the requirement placed on IOUs that were given a baseline that reflected each IOU's unique situation in 2003.

Rationale for Difference: There are several reasons for this difference from the treatment of IOU baseline standards. First, IOUs do not compete against each other for customers, as do ESPs. In order for ESPs to compete fairly with each other going forward, they should each have the same requirements placed on them, so that they each factor the same cost components into bids for prospective DA customers. Secondly, unlike the IOUs, a number of ESPs literally had zero RPS compliant resources prior to 2006. In contrast, all three of the IOUs had some starting level of RPS compliant resources due to the fact that they were all required to purchase renewable energy from Qualifying Facilities ("QFs") under the Public Utilities Regulatory Policy Act ("PURPA").[16] PURPA provided the IOUs at least some head start to achieving the 2010 goal. ESPs had no such requirement, and hence do not necessarily have any renewable portfolio from which to build. Therefore, in the event that AReM's proposal is adopted unchanged, ESPs would have to meet at least 1 percent of their load with renewable resources in 2006, 2 percent in 2007 and so on until 20 percent in 2010.

If the Commission is concerned that ESPs starting with a zero baseline and increasing their procurement by a minimum of 1 percent per year will not approach the 2010 goal quickly enough, they should consider that the overall AReM proposal still requires meeting the 20 percent goal by 2010 and has significant financial penalties for non-compliance.

C. Reporting Requirements

The Commission clearly directed ESPs to report their progress toward meeting RPS requirements in D. 05-11-025. The question we have before us is how ESPs should do that. AReM has what it believes is a relatively simple proposal for how to do that for the year 2006. This proposal may need to be modified for the post-2006 period as the Western Renewable

[16] The IOU 2003 baseline percentages were established by the Commission in R.04-04-026, p. 4, as follows: SDG&E, 3.6%; SCE, 17.7%,; and PG&E, 11.5%.

Energy Generation Information System ("WREGIS") becomes operational. AReM's reporting proposal has three main elements:

1. Number and Timing of Reports

IOU Requirements: Two annual reports, in March and August.

Proposed ESP Requirement: Once annually, ESPs shall report on compliance for the previous calendar year on May 1 of the following year.

Rationale for Difference: The IOUs are required to report twice per year in March and August but have a variety of other requirements related to RPS Procurement Plans, running RFOs, etc. that do not apply to ESPs and therefore ESPs should not have to do an August interim report. The choice of the May 1 date is in compliance with the recommendation of Staff in the White Paper. They note that having the compliance report submitted on May 1 will coincide with LSE completion of the CEC RPS-Track form and FERC Form 1. AReM supports the Staff proposal. This date will also permit ESPs to obtain complete information about their prior year's load and resource purchases and then take the additional steps required to complete the reporting process. The date is the same as the first IOU reporting date so that the Commission can get a view of the previous year's compliance from all retail providers at the same time.

2. Report Format

IOU Requirements: D.05-07-039 endorsed a reporting template put forward by the Green Power Institute. This was attached to the decision at Appendix A.

Proposed ESP Requirement: AReM proposes that ESPs should use the Green Power Institute's proposed template attached to D.05-07-039 as Appendix A to summarize their RPS compliance for the previous year. To the extent that this form is modified through workshops, AReM expects to participate in such workshops and hopes that any changes would still allow the form to be used by ESPs. This form is also attached to this filing as Attachment 2.

3. Verification

IOU Requirement: The Commission has extensive legal authority to look into utility records and verify utility compliance with its decisions and rulings.

Proposed ESP Requirements: ESPs operate under different legal authorities than IOUs, so therefore the mechanism for verifying ESP compliance with the RPS will be different. AReM proposes below a mechanism that is similar to the mechanisms used by the CEC to verify compliance with the Power Content Labeling requirement and by the Green-e program for verifying compliance with the Green-e certification of green power products.[17]

In addition to the summary form described above, ESPs would also have to provide an attestation by an officer of the ESP that, to the best of his or her knowledge, the summary statement on the template is true and accurate and that the renewable resources were sold once and only once. An example of such an attestation form is attached to this filing as Attachment 3. It is an attestation form used by the CEC for similar purposes (SB 1305 - Power Source Disclosure Program) and could be easily modified in the form's title to reference the Commission's adopted RPS rules. Additionally, a similar attestation is being utilized by the Commission for Resource Adequacy compliance demonstrations.

In order for the Commission to verify the validity of the renewable resources claimed in the summary report, and attested to by the ESP's officer, ESPs would be required to obtain and maintain on file signed attestations from renewable resource sellers (similar to the Green-e and CEC SB 1305 Power Content Label verification process) that include:

- Identification and Registration of renewable power plant sources to determine where and what the sources are;

[17] Parties interested in finding out more about the Green-e certification should go to http://www.green-e.org/ipp/vprocess.html. To learn more about the CEC's Power Content Labeling Verification, go to http://www.energy.ca.gov/sb1305/index.html.

- Declaration of the quantity sold and dates sold for either RECs or bundled renewable power;
- Declaration from the seller that they were "sold once, and only once" along with all renewable and emissions attributes and were not claimed by another entity to meet other requirements. See Attachment 4 for a sample renewable seller attestation form from the Green-e program. (This is provided as an example, however it is not a form that AReM necessarily endorses.)

Once the WREGIS program is up and running, which is expected to be in 2007, the Commission should be able to replace the requirements here with a report generated from the WREGIS system that shows which renewable resources were committed to which retailer's "account" and be able to track back the information asked for here in item 4. This should simplify the reporting process for ESPs and improve the overall quality of data, and hence streamline the Commission's ability to verify compliance for the entire RPS program across all participants.

The back-up attestations from renewable sellers described above would be submitted to the Commission upon request. In other words, the Commission could spot check any ESP annual report by requesting the back-up detail. The Commission might consider checking all of the ESPs annual reports for 2006 and from then on only doing random spot checks and checks of summary reports that raise issues of concern to staff.

AReM recommends that, as a general rule, access to the confidential ESP data submittals, and any supporting confidential information, should be limited to the Commission staff and members of the CEC staff that are directly involved in the verification and enforcement of ESP compliance with the RPS. Such access to ESP data should be subject to a protective order and

non-disclosure agreement. The information requirements of all interested parties in the Commission's proceedings on the RPS can and should be met with aggregated ESP data. The Commission should direct staff to prepare summary tables of the data contained in each set of ESP data submittals, and compile the tables of aggregated ESP data into public documents for the use of interested parties.

The reason AReM requests confidential treatment of the individual compliance reports is that they will contain commercially sensitive, competitive information. For example, the attestations will show exactly how many kWh or RECs were purchased from which generator, and when. This information would let a competitor know who the ESP's suppliers were and they could potentially try to acquire that source of supply for themselves. The type of renewable portfolio supply strategy an ESP is pursuing could also be inferred from the filing and used by sellers of renewable energy to increase the price to the ESP and ultimately to the consumer. These reasons justify the confidentiality approach outlined above.

D. Flexible Compliance Mechanisms

There are several different flexible compliance mechanisms which would greatly aid the ESPs' attainment of 20% by 2010 and this proposal will address them individually.

1. <u>Forward Banking</u>

<u>IOU Requirement:</u> IOUs are allowed unlimited forward banking, that is, any over-compliance in one year can be carried forward to meet the Annual Procurement Target (APT) in following years.[18] The Commission found forward banking consistent with the language of P.U. Code § 399.14(a)(2)(C), which allows excess procurement in one year to be applied to

[18] D.03-06-071, p. 43.

subsequent years.[19] In addition, the Commission said that forward banking "simply makes sense"[20] because it provides an incentive for early compliance and can be used to smooth out the lumpiness of acquiring renewables in large contracts.[21]

ESP Requirement: The Commission has already determined in D.05-11-025 that ESPs should be allowed to bank excess procurement without limitation for the same reasons that it makes sense for IOUs.[22] AReM agrees with this conclusion and is seeking no modifications to the mechanism.

2. Backward Banking

IOU Requirement: IOUs are allowed backward banking under certain circumstances. That is, if in a particular year a utility does not reach its APT it can unilaterally decide to cover up to 25% of its APT by over-procuring in the next three years. If its deficiency in any one year is larger than 25%, it can cover that deficiency by over-procuring in future years only with Commission approval after a showing that at least one of the following four conditions exists:

- Insufficient response to an RFO
- Contracts already executed will provide future deliveries sufficient to satisfy current year deficits
- Inadequate public goods funds to cover above-market renewable contract costs
- Seller non-performance[23]

Finally, only renewable resources in excess of a current year's APT can be applied to cover deficiencies in previous years.[24]

---

[19] *Id.*

[20] *Id.*, p. 44.

[21] *Id.*

[22] Section 399.14 (a)(2)(C).

[23] D.03-06-071, p. 50.

ESP Requirement: The Commission has already determined in D.05-11-025 that ESPs should be allowed to use backward banking in the same manner as the IOUs.[25] AReM agrees with this conclusion and seeks no modifications to the mechanism.

3. Short-Term Contracts

IOU Requirement: Minimum of 10 year power purchase contracts.

ESP Requirement: Although D. 03-06-071 set the minimum contract length for IOUs at 10 years,[26] D.05-11-025 raised the possibility of short-term contracting (less than 10 years) for ESPs, CCAs and small and multi-jurisdictional utilities.[27] AReM appreciates the Commission's willingness to explore a variety of options for flexible compliance with the RPS requirement. AReM proposes that contracts of any length, including short-term, be allowed to count towards RPS compliance for ESPs. With the state's ongoing suspension of direct access and a continuing uncertain regulatory environment, ESPs do not procure energy for 10-year periods because their customers do not find it prudent to execute long-term DA contracts in this continuing climate of regulatory uncertainty. DA customers typically only contract for a 6- to 18-month term. An ESP with multiple customers would typically have a portfolio of contracts with a range of expiration dates.

In order to serve such a portfolio, an ESP typically has a portfolio of supply contracts from generators or wholesalers. ESPs try to match the amount of demand they have on the retail side with the right amount of supply from the wholesale market in order to limit their risk. Forcing ESPs into 10-year power purchase contracts would impose significant uncompensated

---

[24] *Id.*, pp. 48-50.

[25] D.05-11-025, Conclusion of Law No. 1.

[26] D.03-06-071, p.58

[27] D.05-11-025, Ordering Paragraph No. 7.

risk on them since they do not have 10-year retail sales contracts. This risk is increased by the fact that competition between direct access and bundled service is currently a one-way street. Direct access customers can return to bundled service but bundled service customers cannot select direct access. Unless and until this one-way street is changed and the retail market is re-opened, ESPs who purchase 10-year supply contracts would be highly likely to lose customers during that period, with no ability to get new customers, except from other shrinking ESPs. This simply is not a viable and sustainable business practice.

Additionally, the Sarbanes-Oxley law[28] has imposed a number of new risk management requirements on corporations. This directly affects ESPs because they are not allowed to go out beyond their current portfolio of customers and take a "long" power position without having significant cash reserves to compensate. So, a ten-year minimum contract length poses a risk of being at odds with Sarbanes-Oxley compliance, as well as internal risk management standards.

On the other hand, the situation for the state's IOUs is significantly different. With a few exceptions, such as community choice aggregation, the majority of their customers cannot leave them. And, if they do lose load for some reason, the IOUs have the ability to seek cost recovery for lost revenues. Recent examples of this include the Competition Transition Charge, the Historical Procurement Charge and the Direct Access Cost Responsibility Surcharge.

Allowing short-term purchases is especially important for ESPs since the customer's commitment to the retailer extends only for the duration of the contractual relationship. ESPs' loads change from month-to-month as contracts expire, renew or "new," existing DA customers are signed away from other ESPs. Short-term purchases are essential to allow ESPs to meet their RPS requirements and to deal with load migration. Short-term purchases also provide another

[28] Sarbanes-Oxley Act of 2002, PL 107-204, 116 Stat 745.

potential source of income to renewable generators who may have excess energy to sell for limited periods of time.

4. Unbundled Renewable Energy Credits (RECs)

IOU Requirement: IOUs are not allowed to use RECs that are unbundled from the underlying electricity.

ESP Requirement: AReM proposes that ESPs be allowed to use RECs as part of a toolkit of flexible compliance mechanisms in order to facilitate compliance with the RPS. D. 05-11-025 itself recognized the potential advantages of RECs:

> RECs may allow RPS compliance without a need for as much emphasis on local or regional transmission congestion. RECs will allow project developers to sell output to multiple small buyers, such as small ESPs, CCAs, or utilities, where particular project sizes do not exactly match the needs of the buyer. In addition, because the renewable potential in California is not equally distributed geographically, RECs will facilitate RPS compliance regardless of load location.[29]

In addition, ESPs have a unique reason for wanting to use RECs. As stated above, ESPs try to match their power supply contracts to their retail load and that load is not growing due to the suspension of direct access. Prior to the commencement of RPS obligations, ESPs that have purchased supply for their retail load with non-renewable power supply contracts may find it difficult to reduce the supply from those contracts without triggering costly penalties or defaulting on contractual obligations. Moreover, since most ESPs procure supply immediately after executing a retail contract, the inability to use unbundled RECs as a compliance tool essentially results in the ESP having to procure excess power. For ESPs, to be forced into a "breach of contract" situation, or to be forced to incur additional costs by procuring excess energy, imposes an unreasonable burden on them. However, if the use of RECs were allowed

[29] D.05-11-025, p. 19

for ESP compliance, ESPs could go out and buy unbundled RECs to meet their RPS requirements and layer the RECs on top of their existing non-renewable power supply contracts, thus avoiding contract penalties associated with reducing supply commitments or having to procure power twice. It is important to note that in the absence of allowing ESPs to use RECs for compliance, it is especially critical that the Commission adopt the ramp-up proposal contained in section B above in order to allow ESPs to phase-in renewable contracts as non-renewable contracts expire.

Most other jurisdictions that have both RPS requirements and allow competitive electric suppliers (ESPs in California parlance) allow the use of RECs. A recent report from Lawrence Berkeley Labs on RPS compliance states:

> The overall RPS design in California, with renewable energy procurement plans, advance approval of bid solicitations, PRG review of contracts, and CPUC contract approval, may simply not make sense for ESPs and CCAs. In other states with RPS policies, ESPs have generally complied with the RPS through short-term REC purchases—an option not currently allowed in California.[30]

In requesting that the Commission allow ESPs to use RECs for compliance in 2006, AReM assumes that the reporting requirements proposed in Section C above are also in place to provide assurance, through legal attestations, that in fact the use of RECs does not become an abuse of RECs. The process of using RECs and verifying the proper use of RECs through reporting, attestations or third-party audits is in use by the Green-e organization and is used in other jurisdictions throughout the country. This reporting and tracking challenge will be simplified for both the Commission and the ESPs once WREGIS is up and running in 2007.

---

[30] Wiser, R., M. Bolinger, K. Porter, H. Raitt, *Does It Have To Be This Hard? Implementing the Nation's Most Aggressive Renewables Portfolio Standard in California,* Environmental Energy Technology Division, Lawrence Berkeley National Laboratory, August 2005, p.15.

AReM is gratified that the Commission is positively disposed toward exploring the use of RECs[31] and understands that this proceeding will explore this topic in depth. RECs are widely used in both voluntary and compliance markets throughout the country and many other jurisdictions have established rules for their use and have flourishing renewable markets. AReM will provide greater comments on this topic at the appropriate point in this proceeding. Overall, AReM believes that eventually giving all retail providers, including IOUs, the ability to use unbundled and tradable RECs will help reduce the cost to electric consumers of RPS compliance by providing load-serving entities more "tools" with which to comply.

Philosophically, AReM believes the role of the Commission is to set the standards, provide the verification procedure and be ready to levy penalties for non-compliance, but its role should not be to micro-manage how retail providers comply with RPS standards. That way, a retail provider is responsible for competitively managing a portfolio of renewable resources -- short and long-term contracts, and RECs -- to meet its RPS targets.

E. Penalties and Enforcement Procedures

IOU Requirement: There are two established mechanisms for the Commission to enforce compliance with the RPS for IOUs. First, Section 399.14(d), enacted as part of SB 1078, requires the Commission to exercise its authority to initiate contempt proceedings pursuant to Section 2113 to compel a utility to comply with its approved renewable procurement plan. Second, in D.03-06-071, the Commission adopted an "upfront and automatic" monetary penalty of five cents per kWh to be assessed against any utility that fails to meet its APT for a given year. The "upfront" part of the Commission's description of this second mechanism refers to the fact that the amount of the penalty—five cents per kWh—is predetermined; "automatic"

[31] *See* D.05-11-025, pp. 15-20

refers to fact that the penalty is triggered automatically when an IOU submits a compliance report that reveals an APT shortcoming. For the reasons discussed below, neither of these mechanisms can be applied to ESPs. Therefore, an alternate mechanism is needed.

ESP Requirement: Consistent with D.03-06-071, AReM proposes that the Commission adopt the same five cent per kWh penalty adopted in D.03-06-071 as the standard penalty for ESPs, with an upper limit of $2.5 million per year per ESP to reflect the smaller size of ESPs. As with the IOUs, however, the Commission should take mitigating factors into consideration when setting the actual penalty amount.

1. Section 399.14(d) Does Not Apply to ESPs.

The contempt proceedings mandated by Section 399.14(d) presume the existence of an approved renewable procurement plan with which a utility has failed to comply.[32] Since ESPs are not required to submit renewable procurement plans to the Commission for approval, they cannot be ordered to show cause for failure to comply with such plans. As discussed below, however, the "show cause" process used for contempt proceedings has merit as a general model for RPS enforcement proceedings involving ESPs.

2. The Commission Does Not Have the Authority to Impose Automatic Penalties on ESPs.

The "upfront and automatic" penalty mechanism adopted in D.03-06-071 raises a different set of issues. When it adopted this enforcement tool, the Commission indicated that it was acting under its "existing authority."[33] While the Commission did not explain further, presumably it was acting pursuant to its authority under P.U. Code Section 701, which provides

---

[32] Section 399.14(d) provides:

> If an electrical corporation fails to comply with a commission order adopting a renewable procurement plan, the commission shall exercise its authority pursuant to Section 2113 to require compliance.

[33] D.03-06-071, p. 50.

that the Commission "may do all things ... which are necessary and convenient" in the exercise of its authority to "supervise and regulate every public utility ..."[34] Since ESPs are not "public utilities," such entities are not subject to the Commission's general regulatory authority under Section 701.[35] Therefore, the Commission cannot rely on Section 701 as authority to impose penalties, automatic or otherwise, on ESPs. Rather, the Commission must look to the enforcement powers expressly granted to it by statute for such authority.[36]

By their terms, most of the statutes bestowing specific enforcement powers on the Commission relate to enforcement actions involving "public utilities" (Sections 2101-2003, 2106, 2107, 2109, 2110, and 2114). Others relates to actions involving "persons" (Section 2112), "common carriers" (Section 2100, 2107.5), "gas pipelines" (2104.5), "railroad corporations" (Section 2115), and, charmingly archaic, "passenger stages" (Sections 2117 and 2119). Specific enforcement powers that the Commission can apply more broadly (i.e., to companies other than IOUs) are limited to those provided in Section 2111 ($500-$20,000 penalty for knowingly violating or failing to comply with Public Utilities Code and Commission orders) and Section 2113 (contempt proceedings).

Exercise of the Commission's authority under either of these statutes (Sections 2111 and 2113) presumes the subject has been afforded due process. In the case of Section 2111, an evidentiary hearing may be required to determine whether the subject acted knowingly. In the case of contempt proceedings under Section 2113, a show cause hearing is normally held. The

---

[34] Section 701 provides in full:

> The commission may supervise and regulate every public utility in the State and may do all things, whether specifically designated in this part or in addition thereto, which are necessary and convenient in the exercise of such power and jurisdiction

[35] D.05-11-025, p. 12.

[36] *Id*.

real world implication of this legal analysis is that the Commission has the authority to impose monetary penalties on an ESP's failure to meet its APT (and for other RPS-related infractions). Before doing so, however, the Commission must first afford the ESP due process.

3. AReM Proposes a Penalty Process for ESPs that Includes a Standard Penalty and Due Process.

While the penalty process adopted in D.03-06-071 does not by itself afford adequate due process, AReM is not suggesting that the Commission throw out the baby with the bathwater. Instead, AReM's proposal builds upon the process adopted in D.03-06-071, with the refinements and additions to that process designed to ensure that ESPs are afforded due process.

Consistent with the process adopted in D.03-06-071, AReM proposes that an ESP whose compliance for the year is below the 75% threshold described above (see Section III.D above) include with its compliance report for the year an explanation for its APT shortcoming. The ESP's explanation for the APT shortcoming would be covered by the officer's attestation discussed above. To the extent the APT shortcoming is due to one or more of the following reasons, which parallel those identified in D.03-06-071 as reasons for waiving the automatic penalties that otherwise would be imposed on an IOU for an APT shortcoming, the ESP would not be penalized:

(1) Inability to secure sufficient resources (either renewable energy or RECs) despite [best/good faith] effort;

(2) Contracts already executed will provide sufficient resources to satisfy the APT shortcoming;

(3) Inadequate public goods charge funds to cover above-market costs;

(4) Seller non-performance; and

(5) Prices offered are elevated due to the exercise of market power.

Consistent with D.04-06-071, the Commission would have 90 days to act. If, based on the ESP's explanation and officer's verification, the Commission determines that the APT shortcoming is due to one or more of the reasons outlined above, no penalties would be imposed on the ESP and no further action would be taken. In the event the Commission determined that the ESP's explanation was inadequate, the Commission would issue an order to show cause.

The order to show cause would specify the portion or portions of the ESP's explanation that was inadequate and the amount of the shortfall deemed to require further explanation. The ESP would be given 30 days to provide additional information. If the Commission is satisfied by the supplemental showing, the ESP would not be penalized. If the Commission is not satisfied, then the Commission would schedule a show cause hearing. Only after such a hearing would the Commission be authorized to impose penalties on the ESP.

F. Since DA Customers Pay the Public Goods Charges, They Should Have Access to Supplemental Energy Payments.

Section 399.15 (a) (2) of the Public Utilities Code establishes a mechanism whereby funds from the New Renewable Resources Account at the CEC can be used to pay for "above-market" costs of meeting the RPS requirement. The Commission has implemented a procedure, in consultation with the CEC, to implement this section of the law. While Section 399.15 (a) (2) clearly applies to electrical corporations, simple fairness dictates that DA customers should receive the same protection against high RPS compliance costs as do customers of the IOUs. All customers, both DA and non-DA pay the public goods charge that funds the New Renewable Resources Account. All customers run the risk that RPS compliance may be costly. Therefore, all customers should have the benefit of protection against "above-market" compliance costs of the RPS.

While AReM feels very strongly that the direct access customers of its members deserve this protection, AReM does not feel that this issue has to be resolved by the Commission immediately and that resolving the issues regarding compliance with the five key requirements from D. 05-11-025 should take precedence in being resolved first. ESPs need the five key requirements to be resolved as quickly as possible if they are to comply in 2006 and resolution of the SEPs issue could slow resolution of the five key requirements.

At this time AReM is merely asking that the Commission affirm the basic principle that DA customers have an equal right to protection from the potential of above-market costs associated with RPS compliance and that workshops in the future will be used to determine the proper way to utilize SEPs so that ESPs' RPS compliance efforts that result in any above-market costs do not get passed on to their customers.

IV. CONCLUSION

ESPs operate under a legal and regulatory regime that is different from that governing the IOUs. In addition, the nature of their business as competitive suppliers put different constraints on them than on monopoly providers. AReM has crafted an RPS compliance proposal that preserves the over-arching goal of 20 percent of retail energy coming from renewable resources in 2010 and tries to maximize the probability of it being reached. This proposal parallels the IOU requirements for RPS compliance where possible, while recognizing and accommodating the significant differences in the positions of IOUs and ESPs. This proposal also draws on the significant experience of the CEC and the Green-e organization in verifying various aspects of renewable energy in the competitive market. It is a good faith effort to comply with the

Commission's directives on the RPS and is intended to maximize the probability of the 20% goal being attained while minimizing the cost to Direct Access customers.

Respectfully submitted,

/s/
Rick Counihan
Managing Director-California
ECOS CONSULTING
274 Brannan Street, Suite 600
San Francisco California 94107
Telephone: (415) 371-0604
Email: rcounihan@ecosconsulting.com

On behalf of
Alliance for Retail Energy Markets

/s/
Daniel W. Douglass
Gregory S. G. Klatt
DOUGLASS & LIDDELL
21700 Oxnard Street, Suite 1030
Woodland Hills, California 91367-8102
Telephone: (818) 593-3939
Facsimile: (818) 593-3911
Email: douglass@energyattorney.com

Attorneys for
Alliance for Retail Energy Markets

Date: February 1, 2006

Attachment 1:

A Comparison of Selective Attributes that Demonstrate Differences between Investor-Owned Utilities ("IOUs") and Electric Service Providers ("ESPs")

Market Characteristic	IOUs	ESPs
Legal Status	IOUs are defined as an "electrical corporation" (P.U. Code Section 218) and are public utilities.	ESPs, by definition, are not public utilities. P.U. Code Section 218.3 specifies that ESPs do "not include an electrical corporation, as defined in Section 218."
Rate regulation	All rates, terms and conditions of service to retail customers are regulated by the Commission.	P.U. Code Section 394(f): "Nothing in this part authorizes the commission to regulate the rates or terms and conditions of service offered by electric service providers."
Terms and Conditions of Service	Offered under standardized Tariffs.	Negotiated with each customer.
Rate of Return	IOUs have imputed rates of return that are built into their rates if they reasonably manage their costs; includes recovery of all reasonable administrative and overheard costs, making achieving their target more likely.	ESPs have no guaranteed rate of return or profitability and face the risk of profit or loss as a regular part of doing business; all administrative and overhead costs must be recovered through individual customer contracts.
Customer Base	IOUs have franchised monopoly service territories enforced by Commission rules and statute.	ESPs have no guaranteed customer base and customers may opt for other suppliers or return to bundled service at the completion of their current contracts.
Threat of Competition	IOUs do not compete among themselves; prior to 9/20/01, customers could opt for DA. New CCAs may form.	ESPs face daily competition from other ESPs and from incumbent IOUs, as well as from CCAs when they form.

Market Characteristic	IOUs	ESPs
Market Share[37]	IOU load has grown from a low of 84.1% in February 2003 to the current 88.1% of statewide load.	Conversely, ESP load has shrunk from high of 15.9% in February 2003 to the current 11.9% of statewide load.
Customer Growth /(Loss)	When DA was suspended in September 2001, IOUs had 10,459,286 customers; as of the Commission's 12/15/05 report, they currently have 11,105,790 customers – a 6% increase.	During the same time period, since the suspension of DA, customers on DA have declined from 78,102 to 49,290 – a 37% decrease.
Customer Migration	Current DA customers may opt for bundled service at the end of their then-current contracts with 6-months advance notice and a commitment to remain on bundled service for 3 years.	Current bundled service customers may not opt for direct access. DA customers who have returned to bundled service may return to DA with six-month advance notice at the close of the 3-year commitment period.
Risk Management	Risk and management of risk overseen by CPUC; risk of loss covered by rates.	Must meet Sarbanes-Oxley requirements as well as Company-specific guidelines for managing risk; losses reduce Company profitability.
Pricing	Rates are set and enforced by the Commission.	Rates are negotiated by contract and enforceable by courts
Customer Competitive Options	Bundled customers are captive to the IOU, with the exception of CCA implementation, until the DA suspension is lifted.	DA customers have several alternatives for service, which include other ESPs, the IOU and future CCA options.

[37] Both Market Share and the Customer Growth/(Loss) on the next line are based on Commission statistics found at: http://www.cpuc.ca.gov/static/energy/electric/electric+markets/direct+access/00thru05.htm

Market Characteristic	IOUs	ESPs
Resource Adequacy	IOUs are subject to 115-117% resource adequacy requirements with Commission-assured cost recovery.	ESPs are subject to the same 115-117% resource adequacy requirements with cost recovery dependent on customer negotiations.
RPS Requirements	IOUs are committed to meeting the 20% by 2010 RPS standard, with Commission-assured cost recovery.	ESPs are also committed to meeting the 20% by 2010 RPS standard, with cost recovery dependent on customer negotiations.
Confidentiality	IOU information submitted to the Commission enjoys significant statutory protections under P.U. Code Sections 583, 454.5(g) and Commission General Order 66-C.	None of these statutory provisions or the General Order covers information submitted by ESPs. ESPs therefore have substantial concerns about the confidentiality of their information.
Regulatory and Legislative Resources	IOUs have significant regulatory and legislative affairs departments with branch offices in San Francisco and Sacramento	ESPs usually have one or two individuals devoted to regulatory and legislative affairs in multiple Western states.

Attachment 2

Appendix A—Green Power Proposed Report Form

Appendix A

APT Reporting Template for March RPS Compliance Filings

Previous-Year APT _____ IPT _____ Current-Year APT _____

	2003 KWh	2004 KWh	…	Previous-Year KWh
Utility Retail Sales				
Renewable Procurement (KWh)				
Biomass				
Biogas				
Geothermal				
Small Hydro				
Solar				
Wind				
Total Renewables				
APT				
Carry Forward - put deficits in parentheses				

Attachment 3—Sample Retailer Attestation

(TO BE COMPLETED BY RETAIL SELLERS
Report to the California Energy Commission
~~Utility~~ Procurement of Renewable Energy By Retail Sellers in 2005 ~~2004~~
ATTESTATION FORM

I, (print name and title) _____**, declare under penalty of perjury, that the statements contained in Schedules 1 and 2 are true and correct and that I, as an authorized agent of** (print name of company) _____**, have authority to submit this report on the company's behalf. I further declare that the kilowatt-hours claimed as specific purchases as shown in Schedule 2, are to the best of my knowledge, sold once and only once to retail consumers. The renewable electricity and associated Renewable Energy Certificates used for RPS compliance have not otherwise been, nor will be, sold, retired, claimed or represented as part of electical energy output or sales, or used to satisfy obligations in jurisdictions other than California, and for no other reason than to comply with California's Renewable Portfolio Standard. I certify that the procurement claimed to meet baseline and Interim Procurement Target, respectively meets those criteria.**

Out-of-state facilities are subject to the same deliverability requirements as in-state facilities. Generation that will be counted for purposes of RPS compliance from out-of-state facilities must be delivered to an in-state market hub (also referred to as "zone") or in-state substation (also referred to as "node") located within the California ISO control area (or delivery point that meets applicable CPUC rules) of the WECC transmission system. The requirements of the two foregoing sentences do not apply to retail sellers subject to AB 200.

Signed: _____

Dated: _____

Executed at: _____

CONTACT INFORMATION

Name

Title

Company Name

Address

City, State, Zip

Phone

Fax

E-mail

Attachment 4—Sample Generator Attestation

GREEN-E GENERATOR REGISTRATION FORM AND ATTESTATION

Reporting Year: _____

Facility Information **Check One: __ TRCs __ Electricity**

Name of Generation Facility:

_____

Company Name ["Seller"]: _____

Address of Facility:_____

_____

Facility ID Number[1]:_____ EIA or QF? (circle one)

Contact Person:_____Title:_____

Telephone:_____ Fax:_____

List the renewable MWh generated in each quarter as a line item or on separate forms. Non-renewable generation can be listed by calendar year.

Fuel Type	Capacity (MW)	# MWh TRCs / Power Sold	Date Facility was 1st Operational (mm/yy)[6]	Period of Generation (Q#/yy or mm/yy)	NOx Emissions (Lbs/MWh)	SO_2 Emissions (Lbs/MWh)	CO_2 Emissions (Lbs/MWh)
Landfill Gas[2]							
Digester Gas[3]							
Biomass[4]							
Geothermal							
Eligible Hydroelectric[5]							
Wind							
Solar electric							
Coal							
Large Hydroelectric							
Natural Gas							
Oil							
Diesel							
Other non-renewable fuel: _____							

Declaration:

I, (print name and title) _____, declare that the (indicate with "x") ____ electricity/ ____ renewable attributes listed above were sold exclusively from: (Seller) _____to: (Purchaser)_____.

I further declare that:

1) all the renewable attributes, including any emissions reduction credits or emissions allowances, represented by the renewable electricity generation listed above were transferred to the Purchaser above;

2) to the best of my knowledge, the renewable attributes were not sold, marketed or otherwise claimed by a third party;

3) (Seller) _____sold the renewable attributes only once;

4) the renewable attributes or the electricity that was generated with the attributes was not used to meet any federal, state or local renewable energy requirement, renewable energy procurement, renewable portfolio standard, or other renewable energy mandate by (Seller) _____, nor to the best of my knowledge, by any other entity;

5) the renewable power sold or renewable power associated with the attributes sold was not used on-site for powering electric generation equipment (parasitic load);

6) the electrical energy that was generated with the attributes was not separately sold, separately marketed or otherwise separately represented as renewable energy by (Seller)_____, _____ or, to the best of my knowledge, any other entity; and

7) NO_x, SO_2, and CO_2 emissions information is provided for all fossil-fueled generation, and NO_x emission information is also provided for biomass, landfill gas, and digester gas generation as required.

As an authorized agent of (Seller), _____,

I attest that the above statements are true and correct.

Signature:_____Date:_____

Place of Execution:_____

Additional Statement Required by Biomass Generators

I attest that no more than five percent (5%) fossil fuels and other fuels that are not on the relevant Green-e list of Qualifying Sources of Renewable Generation, measured on a BTU basis, were used, including as a start-up, pilot or supplemental fuel, to produce the electricity and/or TRCs in the above Green-e eligible biomass generation plant or biomass boiler.

_____ _____

Signature Date

_____

Place of Execution

Additional statement required of Seller selling electricity to Purchaser.

I declare that the electricity listed above was delivered into the regional grid as follows:

- **PJM and all of PA, DE, DC, MD, NJ, WV, VA, MI, OH, & IL for sales in PA, NJ, MD, DC, DE, and VA;**
- **ECAR for sales in OH;**
- **ISO New England for sales in CT, VT, NH, ME, RI, and MA;**
- **WECC for sales in CA, OR, WA and ID; and**
- **NY ISO for sales in NY.**

_____ _____

Signature Date

_____

Place of Execution

This Form is used by the Center for Resource Solutions to verify the accuracy of claims made by retail marketers. The information on this form is held strictly confidential and will not be shared with any other party except in aggregate form.

---

[1] Please enter Energy Information Administration (EIA) identification number for the generating facility. If the facility does not have an EIA number, please enter the utility-assigned Qualifying Facility (QF) identification number.

[2] Annual energy weighted average NOx Emissions data is required for Landfill Gas generation resources located in Maine, Vermont, New Hampshire, Massachusetts, Connecticut, Rhode Island, New York, Minnesota, Georgia and North Carolina.

[3] Annual energy weighted average NOx Emissions data is required for digester Gas generation resources located in New York, Minnesota, Georgia and North Carolina.

[4] Annual energy weighted average NOx emissions data is required for all other non-landfill gas and non-digester gas biomass resources located in: Maine, Vermont, New Hampshire, Massachusetts, Connecticut, Rhode Island, New York, New Jersey, Maryland, District of Columbia, Pennsylvania, Delaware, Virginia, Minnesota, Georgia and North Carolina.

[5] Indicate basis of eligibility for hydroelectric (with "x): __ < 30 MW, __ FERC Relicensed post 1986 (NY or New England only), __ Low Impact Hydro Institute (LIHI) certified.

[6] For facilities that have added new renewable capacity, please indicate the amount and operational date of the new capacity and the existing capacity.

Evaluating Tradable Renewable Energy Credits as a Compliance Mechanism for the California Renewable Portfolio Standard

May 31, 2006

Prepared by:
Ecos Consulting
Carmen Baskette
Rick Counihan

Executive Summary

This report presents an analysis of the use of unbundled, tradable renewable energy credits (RECs) within state-level renewable portfolio standard (RPS) policies.[1] Resolving the issue of whether RECs can be used as a compliance mechanism in the California market is critical to meeting the 2010 targets for all load-serving entities (LSEs) to have 20% of their respective power portfolios comprised of renewable power. To address this issue, the authors focused on how RECs have encouraged cost-effective, new renewable energy capacity development in other states and what conclusions could be drawn from experiences for California.

This study is provided to support the California Public Utility Commission's (CPUC) evaluation of the allowance of unbundled or tradable RECs as part of a toolkit of flexible compliance mechanisms for meeting the requirements of the California RPS. In this study, the authors found that the majority of states with RPS policies have employed unbundled tradable RECs as a compliance mechanism. Cited reasons for the inclusion of RECs as a compliance mechanism include flexibility in compliance, transparent market price signals for renewable resources, increased economic efficiency, and incentives for new development.

While some or all of these benefits have been observed in other states, there are stakeholder concerns about the implementation of a REC market in California. The ability to finance new renewable projects without long-term contracts, potential high cost of compliance with RECs, and potential double counting of RECs have all been stated as key concerns regarding the use of tradable RECs in California. As such, this report aims to address these concerns by answering the following questions:

- Can tradable RECs encourage new renewable energy development?
- Can RECs mitigate RPS compliance costs and thereby reduce costs to consumers?
- What elements are required for successful accounting and reporting for RECs?

In order to answer these questions, the authors conducted stakeholder interviews with industry leaders and performed detailed primary and secondary source research. Information and data gathered from these sources was reviewed and analyzed to determine key findings and implications for the implementation of a REC market in California. The research resulted in the following responses to the key questions posed in this analysis.

- *Can Tradable RECs Encourage New Renewable Energy Development?*
  Yes. By providing an additional revenue flow to new renewable energy developers as well as additional value for market participants, RECs can lead to

[1] This report was prepared by Ecos Consulting at the request of the Alliance for Retail Energy Markets (AReM). AReM is a California mutual benefit corporation whose members are electric service providers that are active in California's direct access market. The positions taken in this report represent the views of AReM but not necessarily those of any individual member of AReM or the affiliates of its members with respect to the issues addressed herein.

more investment in bringing renewable capacity online. RECs as a financial product have been found to provide liquidity to the renewable investment community and to be a tool to be used, in conjunction with both short and long-term contracts, to provide greater efficiencies and lower long-term costs for renewable energy procurement. Further, REC trading establishes a value for the REC and sends a price signal that reflects the need for new renewable development in a market where renewable development relies solely on bilateral transactions.

- *Can RECs Mitigate RPS Compliance Costs and Thereby Reduce Costs to Consumers?* RPS implementation is still in the early stages in all states with these policies and conclusive direct evidence is not available to link REC markets to lower costs of compliance in states that employ them. However, it is clear that a REC market does *not increase* the costs of compliance and that high costs in markets are often directly attributable to other factors such as lack of renewable resource supply and challenges with siting new resources.

- *What Elements Are Required for Successful Accounting and Reporting for RECs?* In their most basic form RECs are an alternative accounting mechanism for renewable energy. The primary elements cited by experts for implementation of successful accounting and reporting for RECs include the following:
    - Verify generator characteristics
    - Issue RECs to generators
    - Verify generation amount
    - Provide permanent retirement mechanism
    - Protect against double-selling
    - Verify deliverability requirements
    - Provide for banking functionality

  Tracking systems operating in other states are able to achieve each of these elements to varying degrees. Some systems are as simple as a state-commission operated database whereas others, such as the PJM GATS system, provide far greater functionality for regional tracking, accounting, and reporting.

Finally, the following implications for California's consideration of a tradable REC market are presented in this analysis.

1. Tradable RECs provide flexibility for meeting aggressive RPS targets and may help to reduce the cost of compliance to ratepayers.
2. Successful REC markets hinge upon clear and consistent policies with regard to market rules and qualifying renewable resources.
3. Allowing the use of regional tradable RECs to meet California's RPS is both consistent with most other states and with the way California procures conventional (non-renewable) power.
4. Allowing the use of regional tradable RECs to meet California's RPS can potentially reduce the cost of RPS compliance, while at the same time achieve

the public policy goals of increasing fuel diversity, reliability, public health and environmental benefits.

5. Tracking and verification of RECs can be accomplished through building required functionality into WREGIS or compatible interim systems administered by the CEC or third parties.
6. Prior to full scale WREGIS implementation, California could institute an in-state-only REC tracking and verification procedure based on systems employed in Nevada, Wisconsin, and Texas.

In conclusion, this study found that tradable RECs are beneficial for states with RPS policies. While implementation challenges have been faced by states that have adopted RECs, new solutions and lessons learned are available to California's policy makers. There are opportunities for California to institute a viable REC market that encourages new renewable development, provides flexible compliance with transparent price signals for LSEs and avoids pitfalls such as double-counting and market manipulation.

Table of Contents

INTRODUCTION 1

SECTION 1: CONTEXT AND SCOPE OF RESEARCH 2

RESEARCH CONTEXT 2
WHY CONSIDER RECS NOW? 3
SCOPE OF RESEARCH 4

SECTION 2: RENEWABLE ENERGY CREDITS 5

TYPES OF RENEWABLE ENERGY CREDITS 5
UNBUNDLED RECS 5
TRADABLE RECS 5
DISAGGREGATED RECS 6
REC MARKETS 6
VOLUNTARY REC MARKETS 7
COMPLIANCE REC MARKETS 8
REC MARKET POTENTIAL 9

SECTION 3: CURRENT RENEWABLE PORTFOLIO STANDARDS IN U.S. 11

STATES WITH RPS REQUIREMENTS AND RENEWABLE ENERGY GOALS 11
KEY COMPONENTS OF STATE RPS LEGISLATION 14
TRACKING SYSTEM JURISDICTION 14
GEOGRAPHIC RANGE 15
ALTERNATIVE COMPLIANCE PAYMENTS 15
"CARVE-OUTS" OR "EXTRA" CREDITS 15
UNIQUE ASPECTS OF RPS POLICY 16

SECTION 4: REC MARKET ACTIVITIES IN RPS COMPLIANT STATES 18

CAN TRADABLE RECS ENCOURAGE NEW RENEWABLE ENERGY DEVELOPMENT? 18
ROLE OF RECS IN NEW PROJECT FINANCING 21
CAN RECS MITIGATE COMPLIANCE COSTS AND THEREBY REDUCE COSTS TO CONSUMERS? 24
GEOGRAPHICAL NATURE OF RENEWABLE RESOURCES 24
POLICY MECHANISMS FOR MITIGATING EXCESSIVE COSTS 24
REC PRICE HISTORY 24
RECS AND SUPPLEMENTAL ENERGY PAYMENTS 27
WHAT ELEMENTS ARE REQUIRED FOR SUCCESSFUL ACCOUNTING AND REPORTING FOR RECS? 27

SECTION 5: FINDINGS AND IMPLICATIONS FOR CALIFORNIA 30

RESEARCH FINDINGS 30
IMPLICATIONS FOR CALIFORNIA 31
CONCLUSIONS 33
ACKNOWLEDGMENTS 35

List of Tables

Table 1: Estimates of REC Markets from 2004 through 2010 9
Table 2: State RPS Legislation Components 13
Table 3: Components of Active REC Trading Systems 14
Table 4: Reported New and Planned Capacity Additions in States with RPS Policies 20
Table 5: Ranges of REC Prices 2004 - 2006 25

List of Figures

Figure 1: States with RPS Requirements and Goals 11
Figure 2: Example of the Opportunity for Merchant Wind Developers 22
Figure 3: Texas Compliance REC Prices from December 2002-April 2006 26
Figure 4: Massachusetts Compliance REC Prices from July 2004 - March 2006 26
Figure 5: REC Tracking Systems (Operational and Planned) 28

Introduction

The State of California is evaluating the use of tradable, unbundled renewable energy credits (RECs) as a potential additional mechanism for complying with the California renewable portfolio standard (RPS). Ecos Consulting has undertaken this research, at the request of AReM, in support of the effort at the California Public Utilities Commission (CPUC) to establish the rules pertaining to implementation of the state's RPS requirement for energy service providers (ESPs).[2]

The focus of this research was to determine whether the use of RECs, as part of an overall toolkit of flexible compliance mechanisms, would help ensure California meets its stated goal of getting 20 percent of its electrical energy from renewable resources by 2010, while supporting the construction of new renewable generation, reducing compliance costs for California consumers and simplifying regulatory accounting. This report builds upon the existing body of policy research to analyze the new renewable capacity planned in North America and the importance of REC markets in new project financing and reducing RPS compliance costs. In addition to review of published data, an extensive series of interviews with industry experts, regulators, renewable energy project developers, and financial institutions have been conducted to inform this research.

The remainder of this report is structured as follows:

Section 1: Context and Scope of Research
Section 2: Renewable Energy Credits
Section 3: Current Renewable Portfolio Standards in U.S.
Section 4: REC Market Activities in RPS Compliant States
Section 5: Findings and Implications for California

[2] *See* CPUC dockets R.04-04-026 andR.06-02-012.

Section 1: Context and Scope of Research

Section 1 provides both context and a description of the scope of this research effort. There are a wide range of issues associated with REC usage as a compliance mechanism for RPS policies but this report focuses on a few key issues of particular relevance to California's consideration of establishing RECs as a compliance mechanism.

Research Context

In September 2002, California Senate Bill (SB) 1078 created the California RPS which required each load serving entity (LSE) to "increase its total procurement of eligible renewable resources by at least 1 percent of retail sales per year so that 20 percent of its retail sales are procured from eligible renewable resources no later than December 31, 2017." Subsequently the CPUC and the California Energy Commission (CEC), through the adoption of the joint Energy Action Plan[3], accelerated the target to require LSEs to increase their annual percentage of renewable energy to meet 20 percent of their load with renewable energy resources by 2010.[4]

Per SB 1078, [5] the implementation of the California RPS is a joint CPUC and CEC effort where the CPUC is tasked with the following:

- Developing a process for determining the market price referents (MPRs) above which supplemental energy payments (SEPs) will be distributed by the CEC.
- Developing a process for rank ordering of renewable resources to comply with the "least cost" resources that "best fit" the needs of the investor-owned utilities (IOUs).
- Implementing flexible rules for compliance with annual procurement targets, including a three-year balancing period for excess or under procurement in any given year.
- Clarifying the standard terms and conditions for all contracting of eligible renewable energy resources.

In conjunction with the CPUC activities, the CEC is tasked with the following:

- Certifying eligible renewable resources.
- Designing and implementing an accounting system to verify compliance, preventing double counting, and verifying product claims.
- Allocating and distributing supplemental energy payments.

While initial investor-owned utility (IOU) compliance rules have been established, the current CPUC Renewable Portfolio Standard Proceeding (R.04-04-026) is further developing the rules for non-utility Load Serving Entities (LSEs) to comply with the intent of the California legislation. A parallel CPUC proceeding (R.06-02-12) was opened on February 16, 2006, to "develop additional methods to implement the

[3] State of California Energy Action Plan II, Implementation Roadmap for Energy Policies, California Energy Commission, California Public Utilities Commission, September 21, 2005.
[4] California is examining the possibility of increasing the goal to 33% by 2020.
[5] California Senate Bill No. 1078, Chapter 516, Approved by Governor and Filed with Secretary of State on September 12, 2002.

California renewables portfolio standard program," particularly as they relate to energy service providers (ESPs) and community choice aggregators (CCAs).[6]

One unique aspect of the compliance requirements is examination of the proposed requirement that LSEs should be limited to obtaining renewable resources through long-term contracts for bundled renewable energy. The potential use of alternative compliance mechanisms, such as short-term contracts and unbundled tradable RECs, is a key issue under review during this second RPS proceeding.

A final and further consideration that informed this research is that the CEC, along with the Western Governors' Association, is in the process of developing the Western Renewable Energy Generation Information System (WREGIS). This is a renewable-energy tracking system that is designed to track and account for RECs.

Why Consider RECs Now?

In November 2005, CPUC Decision (D.) 05-11-025, recognized the potential advantages of RECs as follows:

> "RECs may allow RPS compliance without a need for as much emphasis on local or regional transmission congestion. RECs will allow project developers to sell output to multiple small buyers, such as small ESPs, CCAs, or utilities, where particular project sizes do not exactly match the needs of the buyer. In addition, because the renewable potential in California is not equally distributed geographically, RECs will facilitate RPS compliance regardless of load location."[7]

In the February 2006 CPUC Order Instituting Rulemaking (R.06-02-012), the scope of this rulemaking includes examining "the potential for use of unbundled and/or tradable renewable energy credits (RECs) for compliance with RPS requirements, including the characteristics or attributes of any RECs allowed for RPS compliance and the status of RECs associated with renewable energy generated by qualifying facilities (QFs) and utility-funded distributed generation."[8]

There have also been a number of recent publications that have weighed in on the issue of employing RECs as part of the California RPS structure. Select publications and references to REC trading include:

- The April 20, 2006 CPUC Staff White Paper "Renewable Energy Certificates And The California Renewables Portfolio Standard Program"[9]
- The joint CPUC – CEC Energy Action Plan II, Key Action 12 in the Renewables section makes the following recommendation:

---

[6] California Public Utilities Commission, Proceeding R.06-02-12, February 16, 2006.
[7] CPUC Decision D. 05-11-025, November 18, 2005, p. 19
[8] California Public Utilities Commission, Proceeding R.06-02-12, February 16, 2006, p. 2.
[9] California Public Utilities Commission, *Renewable Energy Certificates And The California Renewables Portfolio Standard Program,* Staff White Paper, Division of Strategic Planning, California Public Utilities Commission, April 20, 2006.

"Implement a renewable energy certificates trading system for meeting RPS goals."[10]

- A recent paper from Lawrence Berkeley National Laboratory states:

  "The overall RPS design in California, with renewable energy procurement plans, advance approval of bid solicitations, PRG review of contracts, and CPUC contract approval, may simply not make sense for ESPs and CCAs. In other states with RPS policies, ESPs have generally complied with the RPS through short-term REC purchases—an option not currently allowed in California."[11]

- A report written for the CPUC by The Center for Resource Solutions (CRS) asserts that:

  "…allowing RECs to participate in RPS procurements could result in an overall decrease in the winning bid prices for both REC and bundled renewable energy offerings. Expanding the pool of bidders to RPS procurements to include RECs will increase competition and can produce downward pressure on bid prices."[12]

Finally, with the CPUC rulemaking examining tradable RECs, along with the recently issued Staff White Paper on RECs, the numerous publications touting the potential benefits for California of establishing a REC market, and proven successes in other states, it is time to focus on the real implications of a California REC market.

Scope of Research

The authors recognize that significant research has been published on the issue of tradable RECs and REC markets within RPS compliant states and have drawn upon the findings of this prior research. The focus of this effort is limited to evaluating three key questions as they pertain to the use of RECs as part of a portfolio of flexible compliance mechanisms, including long and short-term contracts, to meet the California RPS requirements.

- Can tradable RECs encourage new renewable energy development?
- Can RECs mitigate RPS compliance costs and thereby reduce costs to consumers?
- What elements are required for successful accounting and reporting for RECs?

[10] California Energy Commission, Energy Action Plan II, September 2005, pg. 6

[11] Wiser, R., M. Bolinger, K. Porter, H. Raitt, *Does It Have To Be This Hard? Implementing the Nation's Most Aggressive Renewables Portfolio Standard in California,* Environmental Energy Technology Division, Lawrence Berkeley National Laboratory, August 2005, p.15.

[12] Hamrin, J., R. Dracker, J. Martin, R. Wiser, K. Porter, D. Clement, M. Bolinger, *Achieving A 33% Renewable Energy Target.*, California Energy Commission, November 1, 2005, p. 121.

Section 2: Renewable Energy Credits

This section provides a working definition of RECs as used throughout this research and summarizes the different applications for RECs in markets throughout the United States. While several types of REC products are discussed in this section, the balance of this report focuses on unbundled, tradable RECs unless otherwise noted.

Types of Renewable Energy Credits

Three distinct types of REC products commonly employed today and these include unbundled, tradable, and disaggregated RECs. For the purposes of this study, the default definition of RECs is the definition specified in CPUC decision D.04-06-014 and the RPS terms and conditions.[13] This definition states that one REC:

> "represents the Environmental Attributes associated with one (1) MWh of energy." Where, "Environmental Attributes" means any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to the generation from the Unit(s), and its displacement of conventional energy generation. Environmental Attributes include but are not limited to: (1) any avoided emissions of pollutants to the air, soil or water such as sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO) and other pollutants; (2) any avoided emissions of carbon dioxide (CO2), methane (CH4) and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere; and (3) the reporting rights to these avoided emissions such as Green Tag Reporting Rights.[14]

The definition of specific attributes that are in REC products can vary by state and is usually specified in the RPS legislation or mandate.

Unbundled RECs

An unbundled REC is simply the non-energy attributes of one MWh of generation from a renewable resource. An unbundled REC can be sold or contracted for separately from the underlying electricity commodity but the REC itself cannot be traded among multiple parties. An example of this would be a wind farm where the electricity is sold under a power purchase agreement (PPA) to a utility and the RECs are purchased under a separate contract for use in a green power program.

Tradable RECs

The concept of a tradable REC is that of an unbundled REC with the additional characteristic of not only being separated from the underlying energy but also able to be freely traded among market participants, banked for future use, and subsequently "retired" when used to comply with a state's RPS requirements or a voluntary green power program. In most states, tradable RECs have an established lifetime before they

[13] Appendix A (2), Renewable Portfolio Standard, Standard Contract Terms and Conditions of D.04-06-014, Issued June 9, 2004.
[14] Ibid.

expire, which is typically less than five years. Tradable RECs are currently in use in both in-state and regional markets such as PJM, Texas, Wisconsin, and ISO New England.[15]

Disaggregated RECs
A third REC concept is that of a disaggregated REC product where the individual components of the non-energy attribute are traded separately. This type of product could be used in emission markets to account for higher reductions in greenhouse gases from that of a wind generator versus a landfill gas generator. While disaggregated RECs are not the focus of this research, this is an important planning consideration for the potential future use of RECs in accounting for greenhouse gas reductions. This REC type could be used to assist in the implementation of California's greenhouse gas emission reduction targets.[16]

However, for the balance of this study, the term RECs refer to unbundled, tradable RECs unless otherwise noted.

REC Markets
There are two primary markets operating today in which the value of RECs can be realized: voluntary and compliance markets. When a qualifying renewable resource generates a megawatt of renewable electricity, two potential value streams are created; the value of the energy and value of the REC. In general, the energy value is either contracted for under a power purchase agreement (PPA) or is sold into wholesale energy markets. The value of the REC can be bundled with the energy as a single "all-in" renewable product or can be unbundled from the energy and sold as an unbundled or tradable REC. The unique contracting arrangement for each facility typically specifies the ownership of both the REC and the underlying energy and typically the facility owner or facility investor owns unbundled RECs.[17,18] These RECs can then be purchased either directly or through a broker to count towards an LSE's RPS compliance requirement, an LSE's voluntary green power program, or a customer as a voluntary offset purchase.

In essence, the REC represents the additional value, in excess of the energy value, to the asset owner to offset the above-market costs associated with renewable development versus conventional generation development.

[15] PJM Interconnection is a regional transmission organization serving all or part of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. ISO New England is a regional transmission organization (RTO), serving Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.
[16] California greenhouse gas emission reduction targets were established in a June 2005 Executive Order (S-3-05). This order sets targets to reduce greenhouse gas emissions by 2010 to 2000 levels, by 2020 to 1990 levels, and by 2050 to 80% below 1990 levels.
[17] The authors acknowledge that there is a question in California about who would own the RECs from a Qualifying Facility whose original power purchase agreement did not anticipate the creation of RECs.
[18] A more detailed discussion of REC ownership issues is provided in: Holt, E., R. Wiser, M. Bolinger, "Who Owns Renewable Energy Certificates? An Exploration of Policy Options and Practice", April 2006. (LBNL 59965)

Voluntary REC Markets

In a voluntary market, RECs can be purchased by utilities, other LSEs, or even private companies that do not sell energy. In the case of a utility or LSE purchase, RECs are typically used to meet the environmental attribute requirements of green power programs offered as a voluntary rate for customers. The cost of the REC can be built into a premium in the $/kWh rate paid by a customer. Alternatively, end-use customers can purchase RECs as $/MWh products to offset or mitigate environmental impacts or to promote corporate social responsibility initiatives.

Voluntary Utility Green Power Program

The City of Palo Alto Utilities in California is a good example of a municipality that successfully uses RECs as part of their PaloAltoGreen voluntary tariff to promote the support of renewable energy among its residents and businesses. In this program, customers pay approximately 1.5 cents per kWh over their standard rates to purchase Green-e certified REC products from wind and solar resources.[19] Green-e is a standard set for electricity products whereby certified products must meet requirements identified by the Green-e Governance Board. In short, Green-e products are defined as "25% or more of the electricity supply comes from one or more of the eligible renewable resources; if a portion of the electricity is non-renewable, the air emissions are equal to or lower than those produced by conventional electricity, there are no specific purchases of nuclear power, and the product meets the Green-e new renewable requirement."[20] In this way, the bundled renewable energy does not have to be delivered to the City of Palo Alto's distribution system but rather RECs are purchased in the amount needed to meet the demand of customers participating in this program. The City of Palo Alto Utilities has enrolled 14% of its customers in this voluntary program to date with an associated demand for approximately 30,000 RECs per year. According to the City of Palo Alto Utilities, 97.5% of the RECs are purchased from new or recently built wind farms developed by the Bonneville Power Administration in Oregon, Washington, and Wyoming. The 2.5% balance is met from large-scale solar generation in Alameda County, Davis, and San Ramon, California.[21]

Voluntary "Environmental" Offset Purchases

An example of using voluntary RECs to offset environmental impacts is the Amgen Tour of California.[22] In this case, Clif Bar, a private company and Tour sponsor, purchased RECs to offset 518 tons of carbon dioxide created as part of the bicycle race activities.[23] In order to do this, Clif Bar purchased RECs from *Native*Energy, an energy company that markets renewable energy from Native American wind generation sources. The carbon dioxide offsets from these purchases are calculated as the avoided carbon dioxide emissions from a combined cycle combustion turbine operating in the local area of the wind generator. In this example, the REC represents 1.705 pounds of carbon dioxide reduced per kWh. *Native*Energy purchases the stream of RECs from a wind generator

[19] http://www.cpau.com/programs/green/index.html
[20] http://www.green-e.org/what_is/standard/standard.html
[21] http://www.cpau.com/programs/green/generation.html
[22] The Amgen Tour is an eight-day, 700-mile bicycle race on a route that includes the California redwoods, wine country and the Pacific Coast.
[23] http://www.renewableenergyaccess.com/rea/news/story?id=43378

under a long-term contract and then sells these RECs to customers like Clif Bar on the voluntary market.[24]

Compliance REC Markets

Compliance REC markets are established through the enactment of an RPS policy or mandate. In a compliance market, tradable RECs are purchased by LSEs to meet the targets set forth in the RPS policy. In some cases, a only a limited percentage of RECs relative to bundled renewable energy can be used for compliance.[25] In other markets, all of a LSE's RPS obligation can, or is required to, be fulfilled using RECs.[26] The flexibility of a tradable REC allows those entities that have over-purchased RECs in a compliance year to either sell or bank RECs if they are not required for the current year's compliance.

The most established compliance REC market in the U.S. is in Texas.[27] In this market, the Electricity Reliability Council of Texas (ERCOT) acts as the Program Administrator of the REC Trading Program. Renewable energy suppliers that pass a certification process can be enrolled in the REC Trading Program to sell RECs to the LSEs in Texas. Texas established a capacity target in its RPS rather than a percentage of total MWh sales. A capacity conversion factor (CCF) is used to calculate the MWh equivalent requirement based on each year's new renewable capacity target and the total statewide sales for that year. For example, the 2006/2007 renewable target is 1,400 MW of new renewables and if the CCF is 27%, then the REC requirement would be as follows:

1,400 MW x 8760 hours per year x 27% CCF = 3.3 million RECs

Competitive energy retailers are then required to retire RECs equal to their share of the total statewide retail sales. So if one retailer sells 25% of the statewide volume, then they are required to retire approximately 828,000 RECs in 2006 (3.3 m RECs x 25% share).

In the Texas market, RECs are generated by the renewable facility, purchased by a retailer or broker, and retired by the competitive energy retailer to meet their annual REC requirement. Texas RECs have a 3-year life and each REC is assigned a 14-digit identifying number by the REC program administrator, the Electric Reliability Council of Texas (ERCOT) for tracking and accounting.

In Massachusetts, LSEs are required to supply an annually increasing percentage of their load with RECs. In the Massachusetts REC market, LSEs can "bank" or save 30% of their RECs for one year to apply to the following two years of compliance requirements. For example, if a Boston-area utility purchases 20,000 MWh of biomass-generated RECs in 2006 but only requires 15,000 to comply with its current obligation, then the remaining 5,000 RECs can be put in the bank to be applied to either the 2007 or 2008 compliance

[24] http://www.nativeenergy.com/how-works.html#CNN
[25] An example is Arizona where a maximum of 20% of the portfolio can be met using RECs (Arizona Corporation Commission, March 14, 2006, Decision 68566).
[26] Examples include Texas, New Jersey, and New York
[27] The original Texas RPS was established as part of the Texas Electric Choice Act of 1999.

period. The Massachusetts RECs are accounted using the New England Generation Information System (NE-GIS).

REC Market Potential

The potential economic benefits of REC markets are substantial. As shown in Table 1, a 2005 National Renewable Energy Laboratory study provided estimates of REC market volumes and values in 2004 and 2010.[28] The anticipated growth of REC market size and value appears to be significant in both compliance and voluntary markets with a 2010 U.S. market value of $700 to $900 million.

Table 1: Estimates of REC Markets from 2004 through 2010[29]

	2004 REC Market Size (million MWh)	*2004 REC Market Value ($ millions)*	*2010 REC Market Size (million MWh)*	*2010 REC Market Value ($ millions)*
Compliance Markets	8-13	$140	45	$600
Voluntary Markets	3	$15-$45	20	$100-$300
Total	**11-16**	**$155-$185**	**65**	**$700-$900**

In states with RPS requirements that allow for compliance using tradable RECs, the value of RECs can range quite significantly as observed currently in the price disparity between Massachusetts (over $50/MWh) and New Jersey RECs (Class I at less than $10/MWh).[30] A number of factors, such as geographic region, technology type, and of course, resource supply, contribute to the varied prices and these are discussed further in Section 4.

The prices for RECs in voluntary markets are typically lower than those in compliance markets. "Generally, RECs used in voluntary markets have traded in the range of $2 per MWh to $6 per MWh. However, voluntary markets have supported higher prices for preferred resources, such as solar and wind, or local resources."[31] As reported by Evolution Markets, the average price for voluntary wind REC for 2006 is approximately $5.42/MWh[32]

In both voluntary and compliance markets, RECs provide a potential additional value or revenue stream for renewable developers. The value of RECs differs by market and by region and can be captured as a short-term market transaction or through a long-term contract for REC output. As a product bundled with underlying energy, RECs do not

[28] Holt, E. and L. Bird, Emerging Markets for Renewable Energy Certificates: Opportunities and Challenges, National Renewable Energy Laboratory, January 2005, p. 2.
[29] Ibid.
[30] In New Jersey, renewable resources are divided into two classes of resources. Class I includes solar, wind, fuel cells, geothermal, wave, tidal energy, landfill gas, and sustainable biomass. Class II resources include municipal solid waste (MSW) or hydro generation that meets NJ environmental standards.
[31] Holt E. and L. Bird, *Emerging Markets for RECs, Opportunities and Challenges*. http://www.eere.energy.gov/greenpower/resources/pdfs/0705_naw_ehlb.pdf
[32] Average calculated using three reported offers for 2006 wind tradable renewable certificates of $10.00/, $3.50/, and $2.75/MWh. (www.evomarkets.com)

have the liquidity value for an entity to purchase the REC should they have a higher value for the REC over the underlying electricity. An example of this situation is a LSE that has surplus conventional energy resources but falls short on the percentage of renewable energy required to be in compliance. In this case, the electricity from the renewable generation source is of little value but the renewable attribute or REC would be of high value. Allowing buyers and sellers to capture this value is a key benefit of a successful REC market.

Section 3: Current Renewable Portfolio Standards in U.S.

This section provides an overview of current RPS legislation throughout the U.S. and discusses the unique components of legislation as they relate to REC markets and the potential use of RECs in California's RPS program.

States with RPS Requirements and Renewable Energy Goals

At present, 20 states and the District of Columbia have renewable portfolio standard policies. Two additional states have implemented renewable energy goals or objectives without compliance enforcement. Figure 1 displays a map of these states and their legislated, codified, or recommended targets.[33]

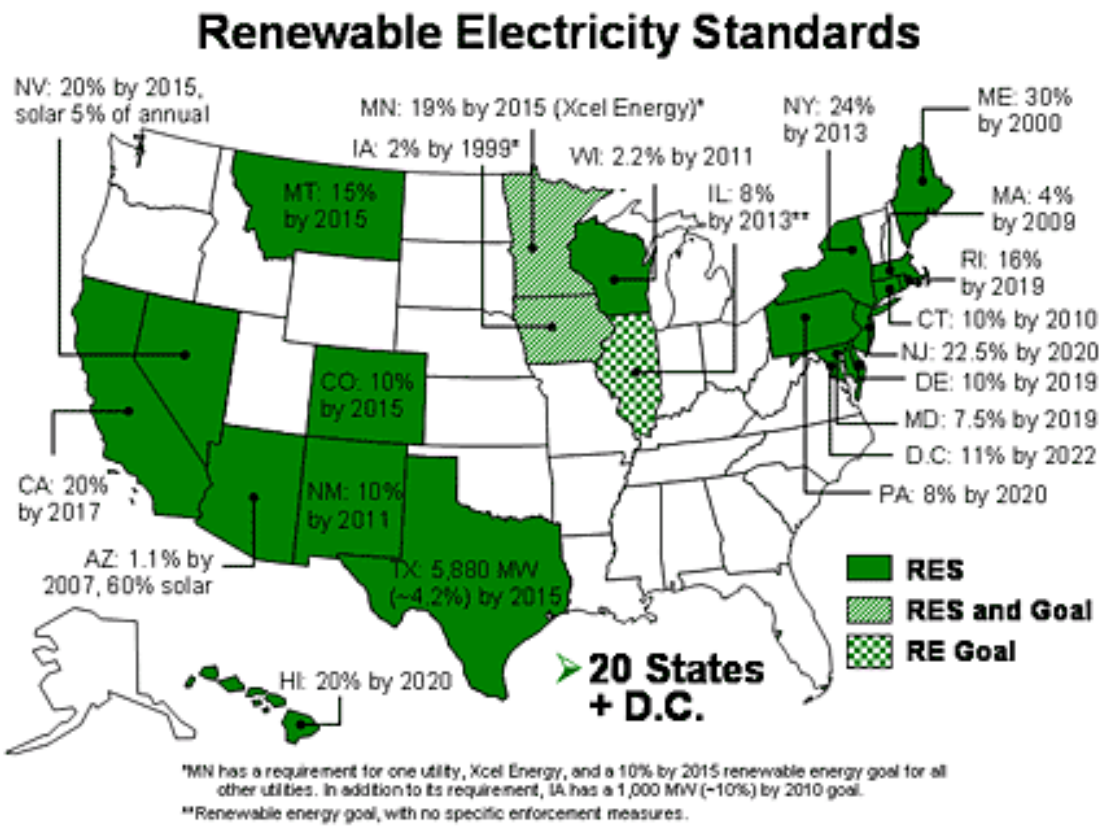

Figure 1: States with RPS Requirements and Goals[34]

Table 2 provides a matrix that includes the timeline of each RPS policy, if the LSEs include competitive energy service providers (ESPs), whether or not REC trading is permitted as part of the RPS policy, and unique aspects of the RPS that could affect a REC market. Currently only four states – California, Hawaii, Iowa, and Minnesota – do not allow for REC trading as part of their RPS compliance. Hawaii has obvious

[33] Since the publication of this map, Wisconsin has increased their RPS to 10% by 2015.

[34] Map is from the Union of Concerned Scientist's websites and data is current as of 3/20/06. For updates: http://www.ucsusa.org/clean_energy/clean_energy_policies/state-clean-energy-maps-and-graphs.html

geographical issues that make RECs less attractive. Iowa has a regulated energy market and has long since met its 1983 established targets. For all utilities other than Xcel, Minnesota's RPS is an objective and not a mandate and RECs have not been introduced in Minnesota. However, RECs are being considered in the Minnesota legislature and should be used once the M-RETS tracking system is operational.[35] Other than these exceptions, it is notable that California is the only state that does not allow for RECs as a compliance mechanism especially considering the aggressive renewable targets and timetable established for its RPS. California is the only RPS-compliant state with competitive suppliers that does not allow RECs.

[35] http://www.puc.state.mn.us/docs/orders/04-0139.pdf

Table 2: State RPS Legislation Components

	State	1st Year of Compliance	Major RPS Update	% or # MW Required	by Date	ESPs	RECs?	Carve-Outs or Credits?	Geographic Range	Alternative Compliance Payments	Unique Aspects of RPS	Tracking System Jurisdiction
1	Arizona	2001	2006	15.0%	2024	Yes	Yes	Solar Carve-Out; Credit Multipliers	Combined: Proof of delivery to AZ customers	No	RECs limited to 20% of compliance portfolio; Extra credit multipliers: Associated Distributed Renewable Energy Requirement	WREGIS
2	California	2003	N/A	20.0%	2010	Yes	No	None	In-State	No	Market Price Referent/Supplemental Energy Payment Structure; Long-term contracts for bundled renewable energy only	WREGIS
3	Colorado	2007	N/A	10.0%	2015	No	Yes	Solar with a % on-site customer required	Regional	No	Maximum impact of average retail rate no more than $0.50/month	Commission-auditable 3rd Party Database: WREGIS under consideration
4	Connecticut	2000	2003	10%	2010	Yes	Yes	None	Regional: In-state counted as 1.25 kWh	No	3 classes of renewable generation; Percentage requirements for each class specified by year; Penalty charge of 5.5 cents/kWh	NE-GIS
5	Delaware	2007	N/A	10%	2019	Yes	Yes	150% credit for wind sited in DE prior to 12/31/2012; 300% credit for solar or fuel cell generation prior to 12/31/2014	Regional	Yes	Customer-sited generation after 6/1/2006 may qualify for RPS compliant RECs; Credits for technology type	PSC-System; May move to PJM GATS
6	Hawaii	2005	N/A	20.0%	2020	No	No	None	In-State	No	None	None
7	Iowa	1990	1991	105	N/A	No	No	None	In-State	No	105 MW capacity requirement; No recent activity	M-RETS
8	Maine	2000	N/A	30.0%	2000	Yes	Yes	None	Delivery into ISO-NE	No	Renewable or efficient resources qualify	NE-GIS
9	Maryland	2006	N/A	7.5%	2019	Yes	Yes	Double credits to solar; Extra credits (10-20%) to wind and LFG generation.	Regional	Yes	2 Tiers of renewables with percentage requirements for each; Renewable Energy Fund to support Tier 1 resources; PUC must establish and maintain REC program; RECs can be banked for 3 years;	PJM-GATS (may design own REC-tracking system)
10	Massachsetts	2003	N/A	4% (increases by 1% per year after 2009)	2009	Yes	Yes	None	Regional	Yes	Must be new resources (post 1998); Banked RECs can be used for up to 30% of year's requirement; Funds from ACP go into the MA Renewable Energy Trust Fund to support new renewable projects	NE-GIS
11	Minnesota	Objective (Xcel mandated)	2003	1,125	2010	No	No	1% biomass carve-out by 2010	Regional serving MN customers	NO	A mandate for Xcel Energy but an objective for remainder of state	M-RETS
12	Montana	2008	N/A	15.0%	2015	No	Yes	None	In-State: Delivery into MT	No	Rural economic development provision; $10/MWh penalty (that is not recoverable in rates)	WREGIS/M-RETs
13	Nevada	2001	2005	20.0%	2015	No	Yes	Solar; 2.4 multiplier for solar	Combined: Generator must be connected to T&D utility on system	No	Portfolio Effiency Credits applicable; Temporary Renewable Energy Development (TRED) Program to facilitate new projects	WREGIS
14	New Jersey	2001	2004	20.0%	2020	Yes	Yes	Solar	Regional	Yes	3 classes of renewables	PJM-GATS
15	New Mexico	2002	2004	10.0%	2011	No	Yes	2x multiplier for biomass, landfill, geothermal, fuel cells; 3x multiplier for solar	Regional	No	Reasonable cost threshold set by Public Utilities Commission, above which a calendar year compliance waiver can be issued; Utilities required to offer voluntary green pricing and education programs	WREGIS
16	New York	2006	N/A	25.0%	2013	Yes	Yes	None	Regional	No	Central procurement through NYSERDA; % Requirement of customer sited generation	System in development (similar to NEPOOL/PJM)
17	Pennsylvania	1998	2004	18%	2020	Yes	Yes	Solar	Regional	Yes	2 Tiers of renewable obligations	PJM-GATS
18	Rhode Island	2007	N/A	15.0%	2020	Yes	Yes	No	Regional	Yes	In-state off-grid or custoemr sited generation may qualify for RPS	NE-GIS
19	Texas	2002	2005	5,880	2015	Yes	Yes	500 MW other than Wind	In-State	No	Capacity Conversion Factors, Compliance Allocation, Offset Credits	ERCOT
20	Washington DC	2007		11.0%	2022	No	Yes	1/1/07; 120% credit for wind and solar before 1/1/10; 110% credit for landfill or wastewater-treatment methane fore	Regional	No	2 Tiers of renewable obligations; RECs can be banked one year prior to first year of obligation (2007)	Selecting (likely similar to PJM)
21	Wisconsin	2000	2006	10.0%	2015	No	Yes	None	Combined: Imports allowed if generators have a wholesale contract with a WI utility	No	Senate bill updating the original RPS was passed in March 2006. Rules and regulations for the implementation of this bill are under development.	WI PSC competitively selected RRC Program Administrator (Plan to move to M-RETS)
	RPS Goal or Objective											
22	Illinois	Voluntary (but RPS proposed)		8%	2013	Yes	No					
23	Vermont	Goal		Incremental	2012	No	Yes					

Key Components of State RPS Legislation

Several key components indicated in Table 2 warrant further mention as they can have an effect on REC market implementation.

- Tracking system jurisdiction
- Geographic range
- Alternative compliance payments
- "Carve-outs" or "extra" credits
- Unique aspects of the RPS policy

Tracking System Jurisdiction

If RECs are a mechanism for renewable energy attribute accounting, then a tracking system is a prerequisite for states employing RECs for compliance. A variety of tracking systems are in place today to account and track REC transactions. These vary from relatively straightforward database system in Nevada, to a third-party operated, in-state only tracking system in Wisconsin, to a regional all-generation tracking system in the PJM territory. All states that are employing a REC market have established some form of tracking to account for and verify compliance. Texas, Wisconsin, PJM and the Northeast States (NEPOOL) have operational certificate tracking systems. Texas, Wisconsin, and Nevada employ in-state only REC tracking systems and are significantly less complex than the regional systems. For example, in Texas, a 14-digit tracking number is assigned to each MWh generated by a certified facility and trades are made through privately arranged contracts as indicated in Table 3. Wisconsin is currently using a third-party consultant to operate their Renewable Resource Credits (RRC) program until the M-RETS system becomes operational. Nevada is currently using a PUC staff developed database for REC tracking.[36,37]

Table 3: Components of Active REC Trading Systems[38]

ACTIVE REC TRACKING SYSTEMS				
	ERCOT	**NEPOOL GENERATION INFORMATION SYSTEM ("GIS")**	**PJM GATS**	**WISCONSIN RENEWABLE RESOURCE CREDITS ("RRCs")**
States with Active or Pending RPS Requirements	Texas	CT, MA, ME, RI, VT	PA, NJ, MD, D.C.	Wisconsin
RPS Compliance	Texas RPS	Each state has own RPS	Each state (and D.C.) has own RPS	Wisconsin RPS
Other Characteristics	1 REC for every green MWh; Participation is voluntary; Two year banking	1 REC for every MWh generated or imported in NEPOOL; Quarterly trading periods; Limited banking; Unlimited forward REC transfers	1 REC for every MWh generated or imported; Active RECs may be transferred at any time; Limited banking depending on requirements of state RPS; Annual trading periods	Limited to generators certified by Wisconsin PSC

[36] Interview with Paul Helgeson, Wisconsin Public Service Commission
[37] Interview with Anne Marie Cuneo, Public Utilities Commission of Nevada
[38] Presentation by Paul N. Belval, Day, Berry & Howard LLP, RECs, RTOs and RPSs: The Three Rs of Renewable Energy, December 14, 2005.

Some states fall within a jurisdiction developing a certificate-tracking program but are still considering alternative systems. An example of this would be Colorado, where the majority of their system would be covered under the WREGIS currently under development for the WECC region. However, since two utilities operating in Colorado (Public Service Company and Aquila) have operations in the Eastern Interconnect, which WREGIS will not cover, Colorado is currently not mandating the use of the WREGIS system.[39]

Geographic range

The geographic range for eligible renewable resources varies by state but is typically either in-state resources only, a combination of in-state and regional resources, or a regional approach. As indicated in Table 2, most jurisdictions allow for a more regional perspective such as in the New England ISO and the PJM territories. This regional approach is more akin to the conventional energy power pool approach. Some states that allow out-of-state contributions to their RPS targets, like Delaware and Connecticut, provide a "bonus" for in-state new generation.

While California has a significant amount of renewable generation potential within its borders, allowing for a WECC-wide REC market could yield lower cost options for very site-specific resources.

Alternative Compliance Payments

Alternative Compliance Payments (ACPs) have been instituted in a number of states with REC markets. ACPs are $/MWh values, typically set by state utility commissions, that LSEs can pay in lieu of purchasing eligible renewable energy or RECs. If renewable energy or REC prices are excessive, then the ACP represents a maximum reasonable cost for compliance in each state. In Massachusetts, ACPs are paid by the utilities to the Massachusetts Technology Collaborative, which administers the Renewable Energy Trust. The Trust uses the additional funding to support both utility-scale and community-scale renewable energy projects.[40] The process of supporting new renewable project financing through penalty payment is also employed in other states.[41]

For example, LSEs have been using ACPs in Massachusetts to mitigate recent short-term REC price spikes associated with limited supply options in the early years of the RPS implementation. These ACPs are similar to California's non-compliance penalties and ultimately go toward supporting new, in-state renewable generation as markets are developing.

"Carve-outs" or "extra" credits

Technology "carve-outs" are mechanisms for encouraging or supporting particular technologies whereby a specified percentage of the total RPS requirement must be fulfilled using the identified generation source. An example of this mechanism can be seen in Nevada where 5% of the total renewable portfolio must be from solar energy.

---

[39] Public Utilities Commission of the State of Colorado, Decision No. C05-1461, Docket No. 05R-112E, Mailed December 15, 2005, Adopted October 7, 2005, p. 10

[40] http://www.mtpc.org/renewableenergy/index.htm#clean

[41] States employing ACPs include Maryland, New Jersey, Delaware, Pennsylvania, and Rhode Island.

Another way to support emerging renewables or local generation is by providing "extra" credit or multipliers for technologies or in-state resources. In this case, one kWh of a specified technology counts as more than one kWh toward meeting the RPS targets. For example, Delaware has instituted a150% credit for wind generation sited in-state prior to 12/31/2012. Another example is New Mexico, where there is a multiplier of 2 for biomass, landfill, geothermal, fuel cells and a multiplier of 3 for solar energy.

Technology carve-outs and extra credit multipliers have also helped to support the development of a mix of renewable resources. California does not presently employ carve-outs or multipliers for specific types of renewable technologies. If used in conjunction with RECs, multipliers can lead to higher prices for scarcer technologies such as solar generation. In particular, there has been a surge of interest in solar PV development in New Jersey and Nevada that can be attributed to the solar technology carve-outs in their RPS regulations.

Unique Aspects of RPS Policy

The column of data labeled "Unique Aspects of RPS" shown in Table 2 is limited to highlights of select aspects of the RPS policies that may affect REC markets and does not show many of the other important aspects of the overall RPS policies. No two RPS policies are alike and some of the unique aspects of RPS policies identified include the following:

- **Arizona**: A maximum of 20% of overall compliance portfolio can be met with RECs. The remainder must come from renewable distributed resources, utility-owned renewable generation, original environmental portfolio resources, or power purchase agreements. This percentage level acts to limit the size of the REC market.

- **Colorado:** A maximum impact on average retail rate of $0.50/month. This translates into a price cap for both renewables and RECs.

- **Connecticut, New Jersey, and Washington DC:** Multiple technology tiers. These states have established tiers for specific technologies where a portion of the RPS must be met with resources from each tier. Higher tiers often include more expensive resources such as solar PV, whereas lower tiers encompass technologies such as wind and biomass. As a result, Tier I RECs when compared to Tier 2 or 3 RECs typically trade at significantly higher values.

- **Maine and Nevada:** Energy efficiency resources can qualify on a limited basis under RPS. This expands the eligible resource base and could lead to lower prices if supply is greater than demand.

- **New Mexico:** Mandated utility voluntary green pricing programs in addition to RPS. This effectively creates two separate REC markets in New Mexico which could drive up REC prices if resources are not available to meet demand.

- **New York:** Central procurement for RPS through New York State Energy Research and Development Agency (NYSERDA). NYSERDA currently has REC contracts but it remains to be seen how central procurement will affect the REC market in New York. NYSERDA aggregates funds collected through the New York RPS public benefits surcharge to finance renewable energy projects using contracts from 3 to 10 years in length. Legislation is pending to change the model and allow NYSERDA to purchase RECs.[42]

- **Texas:** Capacity conversion factors (CCFs) to translate MW target to MWhs for LSEs and the use of offset credits. The CCFs are determined by ERCOT and are set for a 2-year period. The CCF was changed during the 2004-2005 period and a drop in REC prices was observed.

- **California:** The use of a market-price referent (MPR) and supplemental energy payment (SEP) system to mitigate excessive compliance costs is a process unique to California. Proposals for new renewable generation are compared to the MPR and SEPs and applied to any above-MPR costs from resulting long-term (10-20 year) contracts that meet the least-cost/best-fit criteria for utilities. At present, the MPR and SEPs are only applicable to long-term contracts. While the question of whether or not REC purchases could receive SEPs is a key implementation concern in California, the implementation of RECs as a compliance mechanisms does not hinge upon its resolution.

[42] New York State Administrative Procedure Act (SAPA) § 202(1), proceedings: SAPA No. 03-E-0188SA14; (SAPA Nos. 03-E-0188SA15 and 94-E-0592SA38)

Section 4: REC Market Activities in RPS Compliant States

In this section, the market activities related to RPS compliance in states using RECs are evaluated in more detail. Particular attention has been paid to the following research questions related to implementing a compliance REC market in California:

- Can Tradable RECs Encourage New Renewable Energy Development?
- Can REC Mitigate RPS Compliance Costs and Thereby Reduce Costs to Consumers?
- What Elements Are Required for Successful Accounting and Reporting for RECs?

Can Tradable RECS Encourage New Renewable Energy Development?

As RPS policy implementation matures, more information regarding the effect of these policies is becoming available. In this section, the development activities in states with an RPS that allows for REC compliance are examined to help determine what effect RECs have on new development.

As mentioned above, the state with the longest tradable REC market history is Texas. One of the stated purposes for establishing the Texas REC trading program was to increase the in-state renewable generation capacity.

> "The purpose of the Renewable energy credits trading program is to ensure that an additional 2,000 megawatts (MW) of generating capacity from renewable energy technologies is installed in Texas by 2009 pursuant to the Public Utility Regulatory Act (PURA) s39.904, to established a renewable energy credits trading program that would ensure that the new renewable energy capacity is built in the most efficient and economical manner, to encourage the development, construction, and operation of new renewable energy resources at those sites in this state that have the greatest economic potential for capture and development of this state's environmentally beneficial resources, to protect and enhance the quality of the environment in Texas through increased use of renewable resources, to respond to customers' expressed preferences for renewable resources by ensuring that all customers have access to providers of energy generated by renewable energy resources pursuant to PURA s39.101(b)(3), and to ensure that the cumulative installed renewable capacity in Texas will be at least 2,880 MW by January 1, 2009."[43]

To date, ERCOT reports new renewable capacity under its REC program as 2055 MW. This value is the total capacity of certified facilities in the Texas REC program from 2001 when the REC program began with 872 MW to the 2055 MWs to date.[44] TXU Wholesale has attributed the flexibility of the RPS that encourages REC trading and technology choice as one of the drivers of the significant renewable capacity increases

[43] http://www.texasrenewables.com/recprogram.htm

[44] Ercot's 2002 Annual Report On The Texas Renewable Energy Credit Trading Program, Attachment A, p. 2.

in Texas.[45] Other Texas REC market participants have stated that use of RECs played a large role in Texas' early achievement of its renewable targets.[46] With new projects under construction, Texas will exceed its initial 2009 target of 2000 MW of new renewable capacity by the end of 2006. Largely as a result of the success of this program, the Texas PUC recently increased the mandated renewable capacity targets to 5,880 MW by 2015.

Another example is Massachusetts where, initially no new development was observed. The Massachusetts Department of Energy Resources (DOER) indicated in January 2006 that significant new capacity will be coming online to increase local supply. "While DOER expects a comparable shortfall for 2005 RPS compliance, the supply appears to improve for 2006, as new landfill and biomass capacity currently in the pipeline become operational."[47] Some of this difference in reported new resources is due to the fact that Massachusetts accepts renewable energy and RECs delivered into NEPOOL as opposed to being limited to in-state resources. New biomass and landfill gas facilities in New Hampshire, New York, and Maine are expected to contribute to the Massachusetts renewables market in 2006.[48] Massachusetts has had some difficulty siting new projects in-state due to local community opposition.[49] As such, the flexibility of Massachusetts' regional approach will help to ease the high REC -- and associated RPS compliance costs -- in the near-term since facilities in neighboring states are coming online. Examples of regional projects that will be contributing qualified renewable energy to Massachusetts in 2006 include:

- A 17 MW biomass facility in Maine[50]
- A landfill gas project Rhode Island[51]
- Conversion of a 50MW coal plant to biomass in New Hampshire[52]
- Vintage biomass facilities increasing output throughout New England[53]

As some of the permitting and siting issues are overcome within the state borders, a greater percentage of new in-state renewables is anticipated.[54]

Other sources of data for newly completed or re-powered projects are industry associations or state RPS reports. Projections for future capacity additions, while not readily available, are also beginning to be estimated. Table 4 shows two sources of new and planned renewable capacity by state. The Platts column provides anticipated or planned renewable energy projects for 2006 only. The American Wind Energy

---

[45] Presentation by Henry Durrwachter , TXU Wholesale, AWEA RPS Workshop, Chicago, IL, March 8,2006.
[46] Interviews with Renovar Arlington, Ltd, 3 Phases Energy, and Evolution Markets.
[47] Commonwealth Of Massachusetts, Office Of Consumer Affairs And Business Regulation, Division Of Energy Resources, Renewable Energy Portfolio Standard, Annual RPS Compliance Report For 2004 January 9, 2006, p. 2.
[48] Letter from Public Service of New Hampshire indicating new renewable generation capacity. http://www.mass.gov/doer/rps/sma-add.pdf
[49] Examples include the Cape Wind Project off the shores of Eastern Massachusetts and proposed new generation in the Western Massachusetts, Berkshire Mountain regions.
[50] http://www.socialfunds.com/news/release.cgi/5026.html
[51] Interview with Howard Bernstein, Massachusetts Department of Energy Resources, 2/16/06.
[52] http://www.mtpc.org/renewableenergy/green_power/MGPPAwards.pdf; http://www.renewableenergyaccess.com/rea/news/story?id=17548
[53] Interview with Howard Bernstein, Massachusetts Department of Energy Resources, 2/16/06.
[54] Interview with Howard Bernstein, Massachusetts Department of Energy Resources, 2/16/06.

Association's (AWEA) projections are for utility-scale wind energy only but extend beyond 2006. Vastly different estimates are reported across the sources of data, which is indicative of the lack of availability of comparative information on new renewable generation. For example, the Platts data includes a proposed 1267 MW wind project off the shore of Maryland, whereas this same wind project is not reported by AWEA.[55]

Table 4: Reported New and Planned Capacity Additions in States with RPS Policies[56]

		Platts Global Power Report: 2006 Forecasted Capacity Additions (Renewables only)	AWEA Planned/ Proposed Wind Capacity	Allows RECs for Compliance?
(all units are MWs)				
1	Arizona	1	0	Yes
2	California	349	603	No
3	Colorado	407	281.5	Yes
4	Connecticut	2	0	Yes
5	Delaware	0	0	Yes
6	Hawaii	0	61.06	No
7	Iowa	261	249	No
8	Maine	140	110	Yes
9	Maryland	1408	181	Yes
10	Massachsetts	6	519.96	Yes
11	Minnesota	167	128	No
12	Montana	29	51	Yes
13	Nevada	33	190	Yes
14	New Jersey	0	0	Yes
15	New Mexico	0	0	Yes
16	New York	293	481	Yes
17	Pennsylvnia	315	210	Yes
18	Rhode Island	1	0	Yes
19	Texas	298	160	Yes
20	Washington DC	0	0	Yes
21	Wisconsin	354	200	Yes
RPS Goal or Objective				
22	Illinois	450	45	No
23	Vermont	45	147	Yes

Given the early state-by-state reporting, it is evident that there is a large volume of new resources in all stages of development; planning and siting, construction and testing, and initial operation. Significant renewable development is occurring in states with REC programs.

[55] Winergy's proposed Isle of Wight Project http://www.winergyllc.com/isleofwight.html.

[56] Table sources include: Platts Global Power Report, January 5, 2006, Capacity Addition Forecast by NERC Region, pp. 4-7 and the American Wind Energy Association's Wind Energy Projects (current as of April 28, 2006) (http://www.awea.org/projects/)

Role of RECS in New Project Financing

Due to the commercially-sensitive nature of new project financing, there is very limited publicly available data available to determine the actual impact of RECs on project development decisions. As such, the authors conducted interviews with project developers, green energy marketers, and REC brokers to collect anecdotal data related to the role of REC in green project financing. The interviews suggested that RECs can, and do, play a critical role in new project financing. In developing contracts for the output of the new generation, the REC payment in addition to the energy payments contributes to the overall profitability of the new project.

Developers have varied perspectives on how much benefit RECs provide for renewable energy projects but across the board developers interviewed for this paper indicated that in compliance markets that allow RECs, the value is included as part of the overall profitability analysis for projects. In the California market, where the renewable attributes are bundled with the energy in a PPA, the value of "green" is extremely limited. Jonathon Koch of US Renewables Group indicated that the value of a REC representing the renewable attributes may not be enough to make or break a project, the inclusion of a REC value can push a project to an acceptable level of internal rate of return (IRR) or can contribute meaningful incremental income to the project's bottom line.[57]

During a March 2006 RPS workshop, Ryan Wiser of Lawrence Berkeley National Laboratory presented Figure 2 to illustrate how the additional value of RECs in addition to the electricity market price contributes to total financing for a merchant wind developer in different states. In these examples, the market price for the power constitutes the bulk of the project value but the additional REC value in Massachusetts, Connecticut, New York, and Texas push total project value over the upper cost threshold of wind power projects indicating potential profits for a renewable developer in these states.

[57] Interview with Jonathan Koch, U.S. Renewables Group, February 16, 2006.

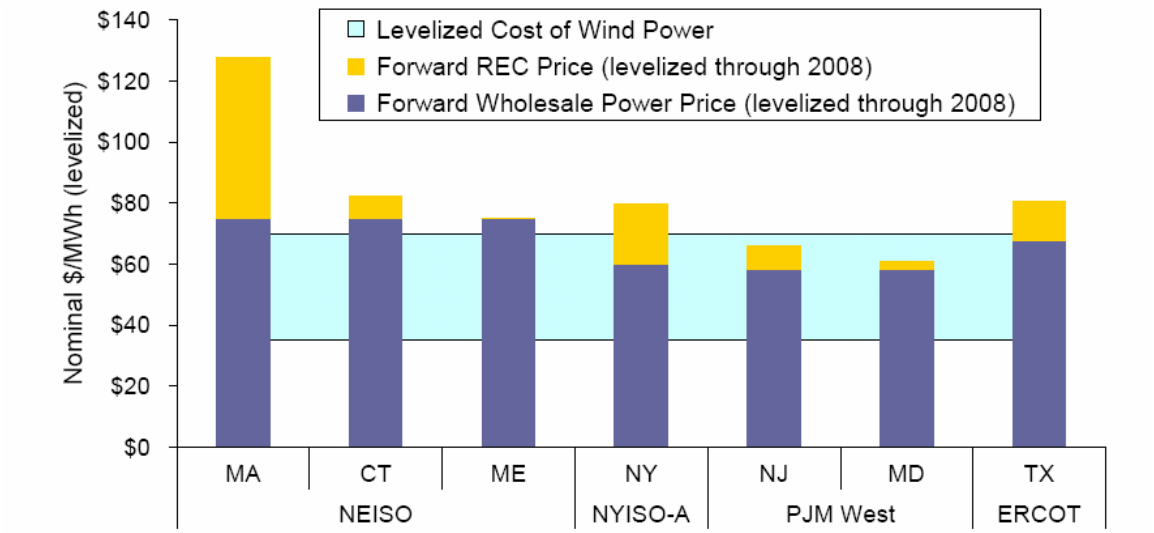

Figure 2: Example of the Opportunity for Merchant Wind Developers[58,59]

REC Value in Financing

As discussed in Section 2, RECs in compliance markets are more highly valued, and contributed to a larger portion of the overall value of a new project, than RECs in non-RPS states or an RPS state that does not allow the use of RECs for compliance. In markets without a REC compliance option, the values of RECs are so discounted that project developers must make the project financially viable without any additional REC value for the project. Thus, the availability of compliance RECs can support a marginal project's bottom line with enough additional value to be built where it would otherwise be left on the drawing board. For example, Andrew Deck of Renovar Arlington, Ltd, a landfill gas generator in Texas, reports that the "the project would have been abandoned without RECs."[60]

The extent to which a REC value stream can affect the ultimate success of a project getting financed appears to vary by technology type and market. For example, for large utility-scale wind projects, the value of RECs is relatively very small when compared to the financial impact of the Federal Production Tax Credit (PTC). For smaller-scale or more costly resources such as biomass or landfill gas which do not qualify for the PTC, REC revenue can help to keep the project viable.

If RECs are not unbundled from the underlying energy source, then they have no liquidity value and the attributes related to the renewable resource are effectively diminished. However, when RECs are unbundled and can be traded to the entities that value them the most, then the greatest total resource benefit is gained for the renewable developer.

---

[58] Presentation by Ryan Wiser, Lawrence Berkeley National Laboratory, Environmental Energy Technologies Division, Energy Analysis Department, AWEA RPS Workshop, March 7, 2006.
[59] Ryan Wiser: Forward power prices represent a flat block of power through 2008, de-rated by 5% to account for the timing of wind relative to a flat block, from NYMEX settle on 2/24/06; Forward REC prices sourced from www.evomarkets.com, January 2006.
[60] Interview with Andrew Deck, Renovar Arlington, ltd., February 14, 2006.

Financing Term and RECs

At present, RECs are most often purchased on a short-term basis, but increasingly long positions in RECs are being observed in more established REC markets such as Texas and Massachusetts. For example, a broker interested in taking a long-term position in RECs could purchase a 10–year stream of RECs from a facility and then sell these on a short-term basis or in the spot market. While this has traditionally not been a particularly viable option for brokers given the nascent nature of REC markets, more contracts of this nature are being observed.[61]

As such, both renewable developers and REC brokers have indicated that the term of the REC contract was not the primary issue, but rather the overall value that RECs contributed to a project's margin. Lenny Hochschild of Evolution Markets indicated that while a long-term steady REC forward curve provides lower-risk value to a project, a short-term high REC value in the early years could also have the same effect of getting a project financed and online.[62]

Prior to the advent of RPS compliance markets, financial lenders had little evidence that the RECs would hold persistent value over the life of a project. There was limited information from which the financial community could draw upon to develop a forward curve of the REC values over time. The issue of term is becoming less of a concern as REC markets evolve. Industry stakeholders have observed that more long-term REC purchase contracts are being executed by LSEs and brokers, where they can either use the RECs as a long-term resource or in the case of brokers, they can sell the RECs back into the market on a short-term basis. In the case of New England, where gas prices are high and the underlying energy yields a high $/MWh and the current REC prices are also elevated, a developer may be able to use a short-term REC contract with high value to get sufficient financing for the life of the project.

Regulatory Certainty

At the American Council of Renewable Energy's (ACORE) Renewable Energy in America: Policies for Phase II October 2005 meeting, one speaker commented on the strong conditions for renewable investments and claimed that, "State renewable portfolio standards and the financial value of renewable energy credits provide very powerful support."[63] However the same speaker, at a subsequent conference, indicated that regulatory uncertainty makes it difficult to lend against the "upside in renewable energy credits or undefined renewable portfolio standards."[64]

In other words, there is a tangible value to RECs in financing and bringing new capacity online but the value is significantly discounted in markets with regulatory uncertainty and limited flexibility and liquidity. This message was consistent across the majority of

[61] Interview with Lenny Hochschild, Evolution Markets, February 17, 2006.
[62] Interview with Lenny Hochschild, Evolution Markets, February 17, 2006.
[63] American Council on Renewable Energy; Statement from presentation: Renewable Energy in America: Policies for Phase II, 17 October 2005; John C. S. Anderson, Head, Power & Project Finance, John Hancock Life Insurance Company; Slide #5.
[64] American Council on Renewable Energy; Statement from presentation: Senior Debt for Renewable Project Financing 2nd Renewable Energy Finance Forum, John C.S. Anderson, John Hancock. Slide#7.

developer interviews conducted for this paper. Thus, the additional value associated with the environmental attributes of renewable energy in California is minimal for project developers. RECs can provide significant financial support to a project, unless the regulatory system is murky.

Can RECs Mitigate Compliance Costs and Thereby Reduce Costs to Consumers?

Several factors contribute to the overall costs of compliance with an RPS. While lack of renewable resource supply in a particular state or region is a primary driver, an inefficient regulatory process for compliance can also contribute to higher compliance costs. The regulatory process for compliance includes, among other factors, the geographical delineation of the compliance region and policy mechanisms for mitigating excessive costs. To determine whether the existence of RECs can act to mitigate compliance costs, the authors examined economic and policy factors in RPS compliant markets.

Geographical Nature of Renewable Resources

Proponents of RECs have indicated that a viable REC market acts to reduce RPS compliance costs. One of the primary reasons cited is the site-specific nature of renewable resources. If the most cost-effective resources are concentrated in one location, then additional transmission and distribution costs or upgrades will be required to transport the bundled energy to the LSE requiring the renewable resource. However, if the renewable attributes are available through unbundled or tradable purchases, then the energy can serve the local system while the REC can be purchased separately. The ultimate cost of the REC is primarily determined by the available renewable supply relative to RPS mandated demand.

Policy mechanisms for mitigating excessive costs

Several states, including California, have incorporated cost mitigation measures should resource or REC costs exceed reasonable levels. As discussed in Section 3, these mechanisms include:

- Alternative Compliance Payments (ACPs) in multiple states
- Colorado's maximum average bill impacts
- California's MPR and SEPs

These policy measures, in effect, define the maximum price or ceiling prices for renewable generation but do not contribute to the cost minimization of renewable development. Allowing limited markets forces, through the inclusion of tradable RECs for compliance, can lead to competitive pricing for renewable energy resources without exposing ratepayers to unmitigated cost risk.

REC Price History

While the available price history of RECs is somewhat limited, there is a growing history of REC prices. REC price signals tend to track both the policy decisions and economics within each region and provide information regarding the anticipated compliance costs in states with active markets. Table 5 shows the maximum and minimum REC prices in

five states during the 2004 through early 2006 period. With the exception of Connecticut, the ranges within the states indicate fairly modest volatility.

Table 5: Ranges of REC Prices 2004 - 2006

Range of Product Prices (Max-Min during 2004-2006)	$/MWh High	Low
Texas	$13.0	$11.5
Massachusetts	$53.0	$52.0
New Jersey (Class I)	$7.9	$6.0
Connecticut (Class I)	$41.0	$4.5
Maine	$0.7	$0.3

The explanation for the extreme changes in the Connecticut prices again indicates the importance of consistent and clear regulation for a reliable REC market. "In August 2005, the Connecticut Department of Public Utility Control found that existing, retooled biomass plants from Maine, and new gas pipeline expansion (pressure reduction) turbines, would qualify as Class I renewable resources under the Connecticut renewable electricity standard. As a result, the market price for renewable energy credits to meet the standard plummeted by more than $30 per megawatt-hour on the prospect of an abundant, and cheap supply of available resources. This decision has seriously undermined the effectiveness of the Connecticut requirement in supporting the development of new renewable energy generation facilities."[65] The situation in Connecticut provides a clear example of the importance of the additional value that RECs contribute to a project. But this value is highly dependent on regulatory certainty for the markets to react appropriately.

Another example from Texas illustrates the impact of regulatory decisions on REC market stability, as evident in Figure 3. In this example, the capacity conversion factor (the legislated factor used to translate the MW target to required MWhs for each LSE) was reduced prior to the end of the 2004-2005 compliance period and prices subsequently dropped in 2005.[66] Additionally, the availability of new wind resources also appeared to push REC prices downward.

[65] http://www.ucsusa.org/clean_energy/energynet/year-end-energynet-policy.html#Connecticut
[66] Presentation by Henry Durrwachter , TXU Wholesale, AWEA RPS Workshop, Chicago, IL, March 8,2006

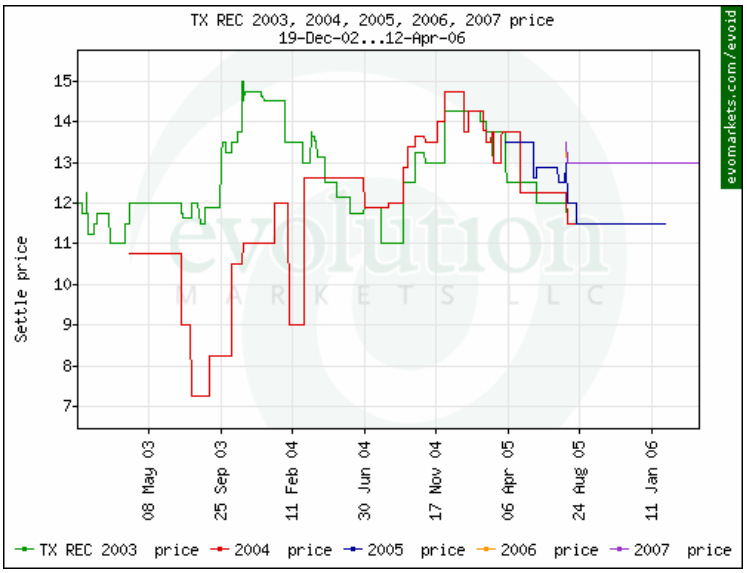

Figure 3: Texas Compliance REC Prices from December 2002-April 2006[67]

As Figure 4 indicates, REC prices in Massachusetts are currently trading at the Alternative Compliance Payment (ACP) level and these payments are being made in lieu of competitive REC purchases. There are many explanations for this, which stem from a supply shortage during the relatively quick ramp-up period for compliance and local siting challenges for new facilities. The Massachusetts DOER is clarifying some of the regulations regarding what facilities qualify and is optimistic that the influx of new renewable supply anticipated in 2006 regionally will substantially shrink the supply shortage and bring REC prices down. The Massachusetts example provides clear evidence that policy mechanisms such as ACPs can and do act to limit market abuse.

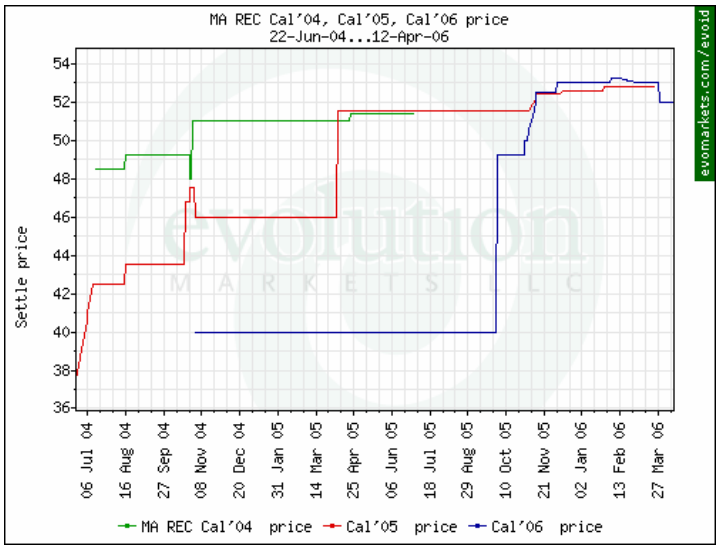

Figure 4: Massachusetts Compliance REC Prices from July 2004 - March 2006[68]

[67] Texas REC data as reported on Evolution Markets website: www.evomarkets.com. Current as of May 1, 2006.

Despite some volatility, which has in many cases been a result of policy changes, early REC markets have demonstrated a reasonably stable and low-cost form of compliance in most states with operating markets. With consistent governing policies, and clear definitions of eligible resources, REC markets allow for liquidity of renewable assets, greater economic efficiency, and lower overall costs to comply with RPS requirements.

RECs and Supplemental Energy Payments

The use of the MPR and payment of SEPs in California's RPS is a unique aspect of this legislation and warrants further discussion when considering alternatives to long-term contracts and flexible compliance mechanisms. At present, Public Goods Charges (PGC) are collected from all customers, both Direct Access (DA) and bundled customers, and the cost mitigation benefits of this construct should similarly be applied to all customers. A portion of the PGC is used to fund SEPs to reduce the cost of compliance with the RPS. However, SEPs are only available for payment on 10 to 20-year power purchase contracts for bundled renewable energy. If RECs are allowed as a compliance mechanism in California, a review of the applicability of SEPs to REC purchases will be important but a decision on the applicability of SEPs would not be required to implement a REC market.

This recommendation is also shared by industry experts concerned with the successful implementation of California's RPS. As noted by the CEC, "Nonetheless, we encourage continued discussion of the use of unbundled in-state RECs under the California RPS, especially for smaller LSEs. To ensure that the state benefits from REC transactions, we also believe that the state's policymakers (whether the CPUC, or the state legislature) should remain open to establishing reasonable limits to the use of unbundled RECs, such as percentage limits or minimum contract term requirements. Additionally, we encourage serious discussion of whether and how SEPs might apply to REC transactions (assuming that SEPs remain, which as noted later, we do not recommend). Allowing unbundled RECs but not allowing REC transactions to access SEPs may provide limited added flexibility, because purchasers may sometimes prefer higher-cost bundled transactions that can receive SEPs to lower-cost REC transactions that cannot."[69] However, "The application of SEPs to REC transactions would require statutory change."[70]

What Elements Are Required for Successful Accounting and Reporting for RECs?

As discussed in Section 3, a sound tracking system is a basic requirement for an efficient REC market because it ensures that the REC accounting is consistent and verifiable for policy makers and market participants. Figure 5 shows a map of regional tracking systems in the U.S. The ERCOT, NEPOOL, and Wisconsin's Renewable Resource Credits systems are operational and the other systems are under development. New York is also developing a tracking system that will likely look like the NEPOOL or PJM systems.

---

[68] Massachusetts REC data as reported on Evolution Markets website: www.evomarkets.com. Current as of May 1, 2006.

[69] Hamrin, J., R. Dracker, J. Martin, R. Wiser, K. Porter, D. Clement, M. Bolinger, *Achieving A 33% Renewable Energy Target.*, California Energy Commission, November 1, 2005, p. 126.

[70] Ibid. *Footnote 87.*

Other states such as Nevada have internally developed an accounting system to track REC transactions. The Center for Resource Solutions has identified the following elements that successful tracking systems:

- Verify generator characteristics
- Issue RECs to generators
- Verify generation amount
- Provide permanent retirement mechanism
- Protect against double-selling
- Verify deliverability requirements
- Provide for banking functionality[71]

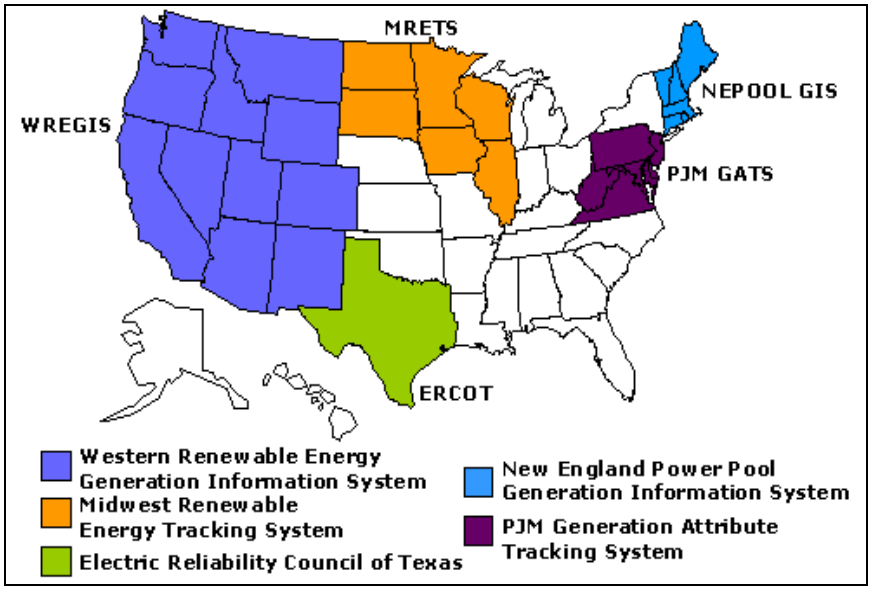

Figure 5: REC Tracking Systems (Operational and Planned)[72]

Evidence from REC tracking systems operating in New England, Wisconsin, Texas, and the PJM territory indicates that tracking mechanisms are successful in practice. The PJM Generation Attributes Tracking System (GATS) is a regional environmental registry and information system that tracks the environmental and fuel attributes of generation and is not limited to renewable energy. Aligned with the CRS functions, the PJM GATS has been successfully designed to:

- Ensure accurate accounting and reporting of generation attributes
- Facilitate bilateral transactions of attributes via certificates between market participants
- Support the current requirements of various state agencies and have the flexibility to accommodate varied and evolving state policies and programs
- Mitigate seams issues with adjoining markets to allow the potential of trading certificates across regions

[71] Presentation by Meredith Wingate, Center for Resource Solutions, AWEA RPS Workshop, Chicago, IL, March 8, 2006.
[72] http://www.pewclimate.org/what_s_being_done/in_the_states/rec_map.cfm

- Promote a robust renewable market
- Leverage market settlement information and environmental information from the U.S. EPA[73]

The ongoing development of the WREGIS tracking system will benefit from the lessons learned in the development and implementation of the existing systems. Refinements for state REC definitions and regional or national interactions between systems are also in development and will undoubtedly meet the requirements for the California RPS. The Needs Assessment Report to the CEC made the following recommendations for the final WREGIS system:

1. Prevent double counting
2. Verify the quantity of renewable energy generated in the Western Interconnection
3. Issue and retire renewable energy certificates with unique serial numbers
4. Track renewable transactions at the wholesale level
5. Verify compliance with state RPS and other state renewable energy policies/programs
6. Create reports about REC transactions for regulators and others
7. Verify green power claims
8. Accommodate commercial trading of RECs
9. Track renewable electricity sales from other states into California

The CEC report formed the basis of scope of the WREGIS system design, and as it is built to these specifications, then the WREGIS functional capability allows for both accurate tracking and verification of RECs in both California and the Western regional market.

In the interim, until WREGIS becomes fully functional in 2007, it may make sense to develop an in-state only tracking mechanism that is WREGIS compatible. Wisconsin is currently operating the in-state RRC program using a third-party database system and Nevada is currently using a staff-developed database to track RECs that will be compatible with WREGIS once it becomes available. Given these experiences in other states, employing an interim system to introduce RECs in California prior to WREGIS implementation appears to be possible while achieving the basic elements of WREGIS.

An additional tool to avoid double-counting and coordinate between regional tracking systems is also in development. According to CRS, "a North American Association of Issuing Bodies (NAAIB) is being considered to ensure compatibility among systems and provide credibility to the emerging REC market."[74]

[73] Presentation by Joe Kerecmann, PJM-EIS, AWEA RPS Workshop, March 8, 2006.
[74] Presentation by Siobhan M Doherty from the Center for Resource Solutions: *The Mechanics of the RECs Market*, Slide 22.

Section 5: Findings and Implications for California

As stated in the state's Public Utilities Code, California's goals with the implementation of a RPS policy are to "promote stable electricity prices, protect public health, improve environmental quality, stimulate sustainable economic development, create new employment opportunities, and reduce reliance on imported fuels."[75] The use of RECs as part of the overall RPS policy to achieve these goals is critical in California because RECs will allow for the flexibility to achieve transparent, low-cost compliance while at the same time providing incentives to renewable developers. To address the concerns about the use of RECs in California, this research endeavored to answer the following three key questions.

- Can Tradable RECs Encourage New Renewable Energy Development?
- Can REC Mitigate RPS Compliance Costs and Thereby Reduce Costs to Consumers?
- What Elements Are Required for Successful Accounting and Reporting for RECs?

This section provides a summary of the research findings and a discussion of implications of these findings for California.

Research Findings

Several key findings developed out of this research and are important to answering the targeted research questions for this analysis.

1. *Almost all states with an RPS allow the use of RECs as a compliance mechanism.*

   Sixteen states with RPS laws allow the use of RECs as a compliance tool. Beyond California, there are only three other states – Minnesota, Iowa, and Hawaii – that do not allow for some form of tradable RECs. Of these three states, Hawaii is geographically isolated reducing the value of a REC system, and Iowa and Minnesota are currently evaluating changes to their RPS. California is the only state with competitive electric suppliers that does not allow tradable RECs as a compliance mechanism. It appears that allowing compliance using RECs contributes to a sustainable model for a vibrant and successful RPS program.

2. *Use of tradable RECs in a compliance market will encourage development of new renewable resources.*

   Throughout the interviews conducted for this research, a consistent message was heard from representatives of the renewable energy community: Long-term contracts are not a prerequisite for the development of new renewable generation. Rather, the existence of a REC compliance market, along with consistent regulation and clear definitions of qualifying resources, provides a foundation for developers and lenders to create forward price curves for RECs, which then can lead to financing arrangements. If short-term REC prices are high enough, or long-term anticipated prices are consistent in a compliance market, then in many cases there is sufficient value to get projects financed.

[75] California Public Utilities Code Section 399.11(b).

3. *Evidence from states that allow RECs for RPS compliance shows that new renewables are indeed being built.*

Reported new and planned renewable capacity is growing among states using RECs as one compliance mechanism. Table 4 above on page 20 shows that most of the states that allow use of RECs are expecting new development, and the states that are expecting the most new development generally also allow the use of RECs.

4. *A sound tracking system is essential for simplifying REC transactions, enforcing compliance requirements, and preventing market abuse when employing RECs.*

All states that are using RECs for compliance have either an operational tracking system (ERCOT, NEPOOL, PJM, and Wisconsin) or are developing a system (New York and Midwest-RETS). The completion of the WREGIS system in 2007 would meet the basic tracking system needs for both California and other Western states.

5. *Economic theory suggests that increased liquidity in the renewable energy markets will lead to greater economic efficiency. However, the evidence to date is inconclusive as to whether the use of RECs results in lower compliance costs.*

The evidence from other states suggests that the overall cost of compliance is a result of many factors including local and regional renewable supply, ability to build new resources, resource eligibility definitions, and regulatory certainty. The existence and use of RECs for compliance purposes appears to have little measurable impact on the cost of compliance in the early stages of RPS implementation. However, if economic theory holds true, the liquidity of REC trading will act to bring costs down over time.

Implications for California

The development of RPS policies in North America has yielded a wide range of approaches and results. While RPS policies are still evolving in many states, there are important insights on the use of RECs from the experience of other jurisdictions that can inform the debate in California as discussed below.

Tradable RECs provide flexibility for meeting aggressive RPS targets and are expected to reduce the cost of compliance to ratepayers.

Allowing for the use of RECs and short-term contracts in conjunction with the existing long-term contract requirement would facilitate compliance for all market participants. On the one hand, LSEs would be able to secure a mix of contracts to match their load requirements, avoiding over-purchasing to meet target or penalties for under-compliance. This can be especially beneficial to smaller LSEs that may not be able to sign long-term contracts or buy large blocks of power. On the other hand the use of RECs also provides renewable generators and developers with an alternative stream of payments, opportunities

to sell a wider range of products to meet their customers' needs, and opportunities to sell in smaller odd lots when they have extra generation available for whatever reason.

In California, the renewable energy resources are not distributed evenly among the physical territories of the utility LSEs required to comply with the RPS. Given the transmission bottlenecks within the state today, REC trading would allow entities to count renewables as part of their portfolio despite these transmission bottlenecks for energy delivery. This will ultimately lower the overall compliance costs for all ratepayers in the state by ensuring that the most economically viable resources are developed.

Successful REC markets hinge upon clear and consistent policies with regard to market rules and qualifying renewable resources.

The value of a REC market to support new renewable capacity development is highly dependent upon the regulatory environment in which it operates. In Connecticut for example, changes in the rules about qualifying biomass facilities caused the REC prices to plummet. Even successful REC markets like Texas are not fully insulated from policy changes, as the REC prices dropped when a mid-period change in the capacity conversion factor was announced. While California's standards for eligible renewable resources are clearly defined, the RPS rules are overly complex and this inhibits both RPS compliance and new renewable development.

Allowing the use of Regional Tradable RECs to meet California's RPS is both consistent with most other states and with the way California procures conventional power.

The majority of states with RPS policies allow for some or all of their requirements to be met through regional supply, i.e. renewable energy or RECs that have been generated in other states. This is not surprising since most states, including California, also procure their generic power regionally. California buys electric energy from a wide variety of traditional resources that are spread out across the Western states. There is no reason for RPS procurement to be made subject to geographic constraints not generally imposed on power procurement.

Allowing the use of Regional Tradable RECs to meet California's RPS can reduce the cost of complying with the RPS, while at the same time still meeting the policy goals of increasing diversity, reliability, public health and environmental benefits.

Allowing regional renewable resources to count toward California's RPS will result in a larger pool of potential renewable resources, which makes it more likely that the state will achieve its 20 percent goal by 2010. In addition, a larger pool of potential renewable resources should also reduce the cost of compliance by allowing the most competitive resources to be developed. At the same time, out-of-state renewable resources still contribute to diversifying California and the region's energy supply, reduce vulnerability to gas price increases and reduce total regional air emissions, including greenhouse gas emissions.

WREGIS will provide the necessary infrastructure to allow accurate tracking and verification of RECs in a Regional Market.

As currently envisioned, WREGIS will include the features identified from other state tracking systems that are necessary for accurate tracking and verification. Lessons learned from experiences in currently operating tracking systems will also ensure the system has effective safeguards against potential abuse.

Prior to full-scale WREGIS implementation, California could institute an in-state-only RECs tracking and verification procedure based on the Wisconsin and Texas processes.

A sound and transparent REC tracking system is necessary to avoid double-counting and to foster trust in compliance. However, a viable in-state market can be achieved prior to WREGIS implementation. Simplified third-party developed tracking systems, similar to the Texas or Wisconsin in-state only approaches, could provide robust tracking for an California-only REC market. Alternatively, a system as straightforward as Nevada's database tracking would meet the basic elements for an early REC market. These systems are less complex than the regional systems in operation and development, but have successfully served to track and verify RECs in both states. Employing a simplified in-state approach for the development of a California REC market prior to a full-scale regional REC market would allow regulators to set expectations and adjust the market as necessary with minimal disturbance to REC market participants.

Conclusions

The research findings indicate the following responses to the research questions posed in this analysis.

- *Can Tradable RECs Encourage New Renewable Energy Development?*
  Yes. By providing an additional revenue flow to new renewable energy developers as well as additional value for market participants, RECs can lead to more investment in bringing renewable capacity online.

- *Can RECs Mitigate RPS Compliance Costs and Thereby Reduce Costs to Consumers?*
  Given the early stages of RPS implementation, direct evidence is not available to link REC markets to lower costs of compliance in states that employ them. However, it is clear that a REC market does *not increase* the costs of compliance and that high costs in some markets are directly attributable to other factors such as lack of renewable resource supply. RECs as a financial product do provide liquidity to the renewable investment community and have been found to be an important tool to be used, along with short and long-term contracts, to provide greater efficiencies and lower long-term costs for renewable energy procurement.

- *What Elements Are Required for Successful Accounting and Reporting for RECs?*
  The primary elements required for accounting and reporting for RECs include:

- Verify generator characteristics
- Issue RECs to generators
- Verify generation amount
- Provide permanent retirement mechanism
- Protect against double-selling
- Verify deliverability requirements
- Provide for banking functionality[76]

Operational tracking systems in other states today are able to achieve each of these elements to varying degrees. As WREGIS is currently under development, the lessons learned from the implementation of these early systems can help inform the implementation of WREGIS to fully achieve these critical system elements.

In conclusion, a wide range of benefits have been observed from the use of RECs as a compliance mechanism in other states, including new renewable generation, ease of compliance for LSEs and regulators, clear market price signals, potentially lower compliance costs, and market liquidity for renewable generators.

[76] Presentation by Meredith Wingate, Center for Resource Solutions, AWEA RPS Workshop, Chicago, IL, March 8, 2006.

Acknowledgments

The authors would like to thank the following people and organizations for their insights and contributions to this research: AReM member companies (Constellation New Energy, Strategic Energy, Commerce Energy, APSES, Sempra Energy Solutions); Roy McCoy, Texas ERCOT; Howard Bernstein, Massachusetts Department of Energy Resources; Anne-Marie Cuneo, Public Utilities Commission of Nevada; John Saintcross, NYSERDA, John Pearce, Iowa Utilities Board, Paul Helgeson, Wisconsin Public Service Commission; Jonathon Koch, U.S. Renewables Group; Lenny Hochschild, Evolution Markets; Andrew Deck, Renovar Arlington, Ltd; Dan Kalafatas, Gabe Petlin, Tim Derrick, 3 Phases Energy; Bill Kallock, Native Energy; Heather Raitt, California Energy Commission; Meredith Wingate, Center for Resource Solutions; Tom Weirach, ACORE; Ginger Teubner, Connecticut Department of Public Utility Control.