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Tradable Renewable Energy Credits and the California Renewable Portfolio Standard

By Daniel Pollak

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EXECUTIVE SUMMARY

Under the law known as the Renewable Portfolio Standard (RPS), California's electricity retailers must purchase 20 percent of their electricity from renewable energy generators by 2017. The state has recently adopted a plan to accelerate this goal to 2010.

However, there are some problems and issues that could make it challenging for electricity retailers to meet these goals. The problems are twofold:

(1) <u>Deliverability Problems</u>

Under current rules, if a utility purchases renewable energy to comply with the mandated RPS goals, the electricity must be physically delivered to the utility. However, the state has serious transmission constraints that can make delivery costly or even impossible. San Diego Gas & Electric (SDG&E) is particularly affected because there is little renewable generation in its service territory.

(2) <u>Contracting Constraints</u>

Current policies require utilities to enter long-term renewable power purchases (in contracts of ten years or greater duration). In 2006, the renewable purchasing mandates will begin to apply to non-utility electricity retailers. These retailers serve primarily commercial and industrial customers and currently account for about 13 percent of the state's electricity sales. These retailers say that California's one-size-fits-all requirement for long-term contracts is infeasible for them for several reasons, including uncertainty about the long-run demand of their customers.

Because of these problems, a variety of stakeholders, including the non-utility retailers, two of the three investor-owned utilities (IOUs), and renewable industry representatives, support making the RPS program more flexible through the use of tradable Renewable Energy Credits.

WHAT ARE TRADABLE RENEWABLE ENERGY CREDITS?

When energy is generated by a renewable resource such as wind or sun, it has the characteristic of being considered renewable energy. This trait of "renewableness" has a value of its own, distinct from the value of the energy in providing electricity. Some purchasers value renewableness because they want to demonstrate support for associated environmental benefits such as reducing air pollution or global warming. In the context of an RPS program, law and regulations create a new source of demand for that renewableness – only renewable energy can satisfy the regulatory mandate.

A Renewable Energy Credit, also known as a REC, turns this "renewableness" into a tradable commodity that can be bought and sold separately from the associated electricity. Tradable RECs are sometimes called "unbundled" RECs, because the renewable attributes are traded separately (unbundled) from the associated physical electricity. RECs are measured in the same units as electricity – kilowatt-hours or megawatt-hours. In a REC trading system, a windmill generating 100 megawatt hours of energy actually produces 100 megawatt hours of electricity and 100 megawatt hours of RECs.

RECs are currently traded in California and elsewhere in voluntary markets. Some private corporations, for example, voluntarily purchase RECS in order to say that they rely on renewable energy for their electricity needs. In effect, a voluntary REC purchase confers what one might call green energy bragging rights for the purchaser.

RECs are also used to satisfy RPS obligations in many parts of the country. These markets are sometimes called "regulatory markets" because the purchaser is using the RECs to comply with a regulatory mandate to purchase renewable energy. California does not currently allow REC trading for RPS compliance.

Advocates of REC trading say it could help address the RPS compliance problems described above. But REC trading also raises a number of difficult policy issues, and not all stakeholders agree the benefits are worth the risks.

THE POTENTIAL ROLE OF REC TRADING IN CALIFORNIA

REC advocates argue that RECs offer a simple way to address both the deliverability and contract problems at the same time that they provide an expanded market to renewable generators. They make the following points:

First, RECs solve the deliverability problem by allowing renewable attributes to go where they are needed without requiring the electricity to go with them. This could reduce RPS compliance costs.

Second, RECs offer an alternative to long-term contracts for electricity. Because RECs are readily traded in short-term markets, they offer one way for non-utility retailers to match the terms of their energy purchases to the terms of their supply obligations to the companies that buy power from them. For example, if a retailer's customer wants a one-year contract for electricity, the retailer can match that to a purchase of an appropriate quantity of RECs to satisfy the RPS mandate.

Third, a REC market would provide renewable generators with a variety of opportunities to expand their sales. As previously explained, RECs can be traded to geographically remote markets without regard for physical transmission constraints. In addition, renewable projects are often financed based on contracts to sell their generation output. The appropriate size of a project, however, may exceed the contract amount for various reasons such as standard turbine sizes. RECs would provide a new way to earn revenues from the extra generation. For example, the generator can sell the extra electricity into the spot market and sell the RECs separately.

POLICY CONCERNS RAISED BY RECS

The idea of creating a regulatory REC market in California raises a variety of policy questions. According to some, REC trading might permit double-counting and undermine some of the key goals of the RPS, such as the promotion of stable energy prices, in-state renewable energy development, and environmental quality. Others are concerned that authorizing the use of RECs for RPS compliance will provide a windfall to existing renewable generators and complicate the state's current program for limiting the overall cost of the RPS program.

Preventing Double-Counting

However RECs are defined, there are broad consensuses that clear rules and a tracking system are necessary to define and prevent double-counting. The attributes represented by RECs should not be re-sellable once they have been counted toward a retailer's compliance with its RPS obligations.

Other states with REC trading have electronic tracking and accounting systems that assign each REC an individual identity number. Such a system helps regulators to keep track of who owns each REC and whether the REC qualifies for that state's RPS program. However, not even a robust tracking system can provide total assurance against double-counting, because it will always be possible for a REC tracked within that system to also be sold outside that system's purview. Penalties and the possibility of auditing might help to deter such abuses.

The California Energy Commission (CEC) is leading the development of such an electronic tracking system for California and 10 other western states, known as the Western Renewable Energy Generation Information System (WREGIS). However, according to the CEC, it may not be operational until 2007. In the meantime, limited REC trading would have to be managed through manual tracking mechanisms.

In-State Renewable Energy Development

Whether to allow importation of unbundled RECs from other states raises a fundamental policy question. On the one hand, allowing out-of-state RECs could result in new renewable generation being built outside of California. Such generation might not provide some of the key benefits intended for the RPS, such as cleaner air and more renewable development in California.

On the other hand, access to out-of-state RECs would enhance the supply of RECs, which in turn could lower prices and reduce RPS compliance costs (which could have economic benefits for the state). Some of the benefits of renewable energy, such as reducing greenhouse gases, would arguably be achieved equally well regardless of whether the renewable generation was in California or elsewhere.

Renewable Energy Development and Price Stability

New renewable projects are capital-intensive, and long-term procurement contracts are usually a prerequisite for developers to obtain financing. Some commenters are concerned that if the California relies too heavily on REC spot markets, new investments will stall and California will fail to protect against future spikes in fossil fuel prices. In addition, some worry that REC prices could themselves be volatile or subject to manipulation.

Advocates of RECs argue in response that nothing in the nature of RECs requires that they be sold only in short-term transactions, and that a long-term REC purchase could provide the price stability necessary for project financing. In addition, nothing about REC trading means that RECs would replace all long-term contracts for renewable energy. Regulators could encourage REC transactions of any duration and could direct regulated utilities to maintain a portfolio of short-, mid-, and long-term renewable purchases, either in the form of REC or power purchase contracts.

Supplemental Energy Payments

Investor-owned utilities comply with the current RPS requirements through long-term contracts procured in a process overseen by the California Public Utilities Commission (CPUC). Generators who win utility contracts are eligible for Supplemental Energy Payments from the California Energy Commission if the renewable energy prices in the contracts are higher than the market energy price referents established by the CPUC. Utilities are not obliged to purchase renewable generation to satisfy RPS requirements once the payments for above-market prices are exhausted for that year.

The Supplemental Energy Payments are funded by the "Public Goods Charge," a surcharge that has been levied on ratepayers of the IOUs since the 1996 electricity market restructuring. So far, none of the utility renewable energy purchases under the RPS have required Supplemental Energy Payments. However, this is likely to change in the future as RPS requirements increase and new renewable resources must be developed to meet them.

Non-utility electricity suppliers argue that REC purchases made to comply with RPS obligations should be eligible for supplemental payments. However, it is not clear how regulators would determine when RECs are eligible for such payments or how much the payments should be. CPUC oversight would be necessary to control costs, which could make an unwieldy program even more difficult to administer, and greatly expand the scope of CPUC oversight over electricity markets.

Environmental Justice

The question is sometimes raised of whether REC trading could worsen environmental inequities – a class of problems sometimes referred to as "environmental justice" issues. For example, some locales could benefit environmentally and economically from more renewable energy production, while elsewhere the mix of local generation would not change.

It is difficult, however, to directly link REC trading policies to environmental justice issues. Renewable energy is likely to be generated where the renewable resources, such as wind or geothermal energy, are abundant, regardless of whether there is REC trading. And the continued operation of polluting urban power plants is affected more by issues of system reliability and transmission constraints than the demand for renewable power.

THE EXPERIENCE OF OTHER STATES WITH REGULATORY REC MARKETS

According to the most recent available reviews, 13 states permit the use of tradable RECs for demonstrating compliance with RPS requirements. A recent study of state programs found that RECs have been most actively used for compliance in Texas, Massachusetts, Connecticut, and Maine. The Texas REC trading program has been called the most successful such program in the country.

As the following table shows, most states with RPS programs have authorized REC trading, and all but three states with competitive non-utility retailers have done so.

RPS States and REC Trading

States with RPS Requirement	Have Non-Utility Retailers	Have or Will Have REC Trading
California	✓	
Arizona	✓	
New York	✓	
Connecticut	✓	✓
District of Columbia	✓	✓
Massachusetts	✓	✓
Maryland	✓	✓
Maine	✓	✓
New Jersey	✓	✓
Pennsylvania	✓	✓
Rhode Island	✓	✓
Texas	✓	✓
Colorado		✓
Montana		✓
Nevada		✓
New Mexico		✓
Wisconsin		✓
Hawaii		
Minnesota		

The various RPS programs around the country accepting or planning to accept RECs for compliance purposes are creating several growing markets. In addition, REC sales in voluntary markets have grown significantly in recent years. Numerous brokers and energy companies market RECs nationwide to wholesale and retail markets.

Most of the states with RPS markets for RECs have or will soon have electronic tracking systems in place that provide some protection against double-counting. As of 2004, electronic REC tracking systems were in place in Texas, Wisconsin, and four New England states. Additional state or regional tracking systems are under development throughout the country that could track RECs for RPS compliance in Maryland, New Jersey, Pennsylvania, and the western United States.

Different states enforce a variety of policies with respect to allowing RECs from outside their borders. Some states, such as Texas and Wisconsin, only allow RECs associated with electricity that is delivered into the state. Others, such as those in New England, accept RECs from other states, with some restrictions.

Some of the issues California faces are unique. Other states do not have a system of Supplemental Energy Payments in their RPS programs. California's requirement for long-term contracts is also unusual.

Two Case Studies: Massachusetts and Texas

The cases of Massachusetts and Texas provide two contrasting examples of the results of introducing REC trading for RPS compliance.

(1) Massachusetts

In Massachusetts, RECs have become the primary means by which retailers comply with the state RPS. In fact, long-term power purchase contracts for renewable electricity have become so unusual as to impair the ability of developers to finance new renewable projects. There is currently a shortage of RECs, prices are high, and it is an open question whether the RPS as currently structured will stimulate enough new renewable energy development.

It appears, however, that the excessive reliance on short-run REC trading in Massachusetts is more a symptom than a cause of the problems in the RPS. The emphasis on short-term transactions is a product of the way Massachusetts deregulated its electricity system. In particular, the rules require the utilities that serve most of the state's load to procure in 12-month contracts. The state has introduced a program to help the financing of renewable development by offering generators long-term REC purchase contracts and price guarantees.

In addition, Massachusetts's regulators say that markets are responding appropriately, if slowly, to the high REC prices, and that new development will bring supply and demand into balance within a few years. However, based on past experience, many of the projects now in the development pipeline will face substantial hurdles in siting and environmental review.

(2) Texas

REC advocates often cite Texas as a more successful example of a well-functioning market. Unbundled RECs have added flexibility to the Texas RPS, but unlike Massachusetts, the utilities rely mostly on long-term contracts for bundled electricity plus RECs. REC prices have been higher than expected, but are still much lower than in Massachusetts. In addition, the Texas RPS program is credited with spurring growth in the state's wind power development, and the state is likely to meet its targets ahead of schedule.

POLICY OPTIONS

The question for California policy makers is whether or how to modify RPS compliance mechanisms to permit more flexibility for utilities and facilitate compliance by non-utility electricity suppliers.

There is a spectrum of options available. California's RPS could continue to rely exclusively on long-term contracts. It could augment the current contracting policy with more flexible compliance options. It could allow limited use of RECs and perhaps eventually permit the wider use of RECs once the regional tracking system is in place and functioning.

A proposal that stops short of REC trading could provide some flexibility in the near-term for IOUs. It is sometimes called "inter-utility swapping." Swapping would allow utilities to avoid the deliverability requirements that currently apply to renewable power purchases counted toward RPS obligations.

For example, suppose San Diego Gas & Electric (SDG&E) wanted to purchase power from a renewable generator in a remote location in Pacific Gas & Electric's (PG&E's) northern California service territory, but transmission constraints made it difficult or impossible for the power to reach SDG&E. In this case, SDG&E could enter a contract to purchase power from the generator, and a separate agreement to swap power with PG&E. The renewable generator would deliver its output to PG&E's service territory. Meanwhile, PG&E would deliver an equivalent amount of power to SDG&E from some other location that avoided transmission constraints.

The end result would be similar to REC trading in that the electricity and the credit for a renewable purchase end up with different buyers. In the example just described, the physical output of the renewable generator ends up with PG&E. The credit for the renewable purchase under the RPS program goes to SDG&E. This is just one example of variations on swapping that could be crafted in different situations. The rule changes to allow swapping could probably be implemented administratively.

Swapping would not provide all the flexibility of RECs. It would be more complicated to coordinate the electricity swaps rather than just trading the RECs. And it would leave open the question of whether non-utility retailers could feasibly meet the RPS contract term requirements.

With respect to contract term requirements, one option that stops short of unbundled REC trading would be simply to allow non-utility retailers more flexibility to use short-term contracts for their renewable energy procurement. It appears that the CPUC already has some discretion to do this.

A different option that would continue to rely exclusively on long-term contracts has recently been proposed by The Utility Reform Network (TURN). This would create a central procurement entity that would buy renewable power on behalf of non-utility retailers. The entity would enter into long-term energy procurement contracts and be regulated by the same process currently used for utilities.

REC trading is thus not the only option available. It is worthwhile, however, to explore in more detail how REC trading might be implemented. We will divide the implementation process into shorter-range and longer-range considerations.

Shorter-Range Considerations

If California adopted REC trading, it is likely that the WREGIS system would ultimately be used as the tracking system. However, the WREGIS system is unlikely to be fully operational before 2007.

One short-run option is the inter-utility swapping just mentioned, which would provide additional flexibility for dealing with transmission constraints. Swapping does not, however, address the main problem for the non-utility retailers, which is their difficulty in using long-term procurement contracts. REC trading is one way the system could provide them with that flexibility. Trading RECs would probably also be simpler for utilities than arranging electricity swaps.

Given that WREGIS is not yet ready, it might be necessary to limit the number of players and the kinds of trading in order to keep the regulation of such trading manageable. Given the concerns about keeping the benefits of the RPS inside California, REC trading could also be limited geographically – for example, only allowing RECs that were initially delivered into the state bundled with electricity.

A similar proposal was made by the Administration and discussed in CPUC proceedings recently. It envisioned a first stage of trading in which only one unbundled trade of each REC would be allowed, and in which the buyer would have to be a participant in the RPS program.

Such proposals for restricted trading might result in a relative lack of market liquidity. On the other hand, they could provide more options and flexibility than are now available. Limited market experimentation would also inform future decisions about the advisability of expanding or contracting trading opportunities. Meanwhile, the CPUC could continue to require that the bulk of utility procurement continue to occur through long-term contracts.

Non-utility electricity suppliers and utilities would want eligibility for Supplemental Energy Payments for REC purchases. However, Supplemental Energy Payments involve a complex set of rules for comparing prices in long-term energy procurement contracts to estimated market prices. There may not be a simple way to modify these rules for RECs, which are not units of energy and are not necessarily bought in long-term contracts. In the interim, it might be preferable to initially use a simple formula for disbursing some Public Goods Charge funds to retailers to help cover REC costs, for example allotting each a share of the available funds based on their electricity market share.

Longer-Range Considerations

Once the WREGIS system is in place (2007 or later), the state would have the infrastructure for a more flexible REC market if that were deemed desirable. For example, WREGIS would be able to readily track a given REC through multiple trades among a broader array of parties, including brokers and others not directly regulated under the RPS. Other rules that could be adjusted over time might include the lifespan of RECs and the ability to bank them. The desirability of allowing or excluding RECs from other states could be revisited if necessary.

If REC trading were to be implemented, the state would need to clarify property rights issues relating to Public Utility Regulatory Policy Act of 1978 (PURPA) and distributed generation contracts. Uncertainties about these issues could unnecessarily limit the supply of available RECs and make it difficult for those involved to make plans about participating in the market. However, the resolution of these issues is not an absolute prerequisite to initiating some form of REC trading.

If renewable project financing appeared to be a problem, the state could introduce new programs like those being tried in Massachusetts, in which the state designates an entity to enter into long-term contracts for RECs or REC options in order to help renewable projects get financing.

The system of using Public Goods Charge funds to subsidize renewable procurement might need to be revisited if REC trading became an integral part of the RPS. The Supplemental Energy Payment system is geared toward IOUs and long-term procurement contracts, but this future RPS would have more diverse participants and more diverse methods of renewable procurement. In the long run, the state might want to devise an entirely new means of distributing Public Goods Charge funds in support of the RPS program.

The following table summarizes the short- and long-range issues just described.

Summary of Interim and Long-Run Options

	Problem/Issue	Interim/Short Run Options (from now through 2007 or 2008)	Long-Run Options (post-WREGIS rollout)
1	SDG&E, PG&E compliance and transmission constraints.	1. Inter-Utility Swapping. 2. Limited REC trading (see #5 below).	Possibly expand scope of REC trading.
2	Non-utility retailer compliance and difficulty w/long-term contracts.	1. Limited REC trading (see #5 below). 2. Flexibility in contract term length. 3. Create procurement entity that makes long-term contracts on behalf of non-utility retailers.	If using REC trading, consider expanding the scope and flexibility.
3	Supplemental Energy Payments for RECs.	1. Allocate reimbursement funds up to non-utility retailer's pro-rata market share. 2. Do nothing – no payments made.	Consider whether to completely overhaul or replace the current Supplemental Energy Payment system.
4	REC property rights for distributed generation and PURPA contracts.	Delegate to regulators, legislate, or do nothing; ideally regulators will resolve in short run but may not happen.	Delegate to regulators or legislate.
5	Verification and tracking of REC transactions.	Regulators implement manual tracking system based on currently available metering and other generator-specific data, plus reviewing contracts to verify procurement.	WREGIS (electronic tracking and accounting system).
6	REC market rules (who can trade, what RECs are eligible, REC banking, unbundling of environmental attributes)	Define limited market that stays within capability of manual tracking system. Err on side of caution.	Adjust market rules over time, balancing goals of RPS, market liquidity, etc.
7	Need for long-term contracts to finance renewable project development.	Continue to require utilities to procure significant portion of RECs via long-term bundled or unbundled contracts.	1. Continue to require some long-term contracts by utilities. 2. Establish state programs to procure RECs in long-term contracts and/or offer options guaranteeing long-term prices. 3. Monitor ability of markets to incorporate REC revenues into contracts and financing.

INTRODUCTION

Under the law known as the Renewable Portfolio Standard (RPS), California's electricity retailers must purchase 20 percent of their electricity from renewable energy generators by 2017. The state has recently adopted a plan to accelerate this goal to 2010.

However, there are some problems and issues that could make it challenging for electricity retailers to meet these goals. The problems are twofold:

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Under current rules, if a utility purchases renewable energy to comply with the mandated RPS goals, the electricity must be physically delivered to the utility. However, the state has serious transmission constraints that can make delivery costly or even impossible. San Diego Gas & Electric (SDG&E) is particularly affected because there is little renewable generation in its service territory.

(2) Contracting Constraints

Current policies require utilities to enter long-term renewable power purchases (in contracts of 10 years or greater duration). In 2006, the renewable purchasing mandates will begin to apply to non-utility electricity retailers. These retailers serve primarily commercial and industrial customers and currently account for about 13 percent of the state's electricity sales. These retailers say that California's one-size-fits-all requirement for long-term contracts is infeasible for them for several reasons, including uncertainty about the long-run demand of their customers.

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WHAT REC TRADING LOOKS LIKE

RECs can be traded in both voluntary and regulatory markets. Some examples will help to illustrate how these markets work.

VOLUNTARY MARKET TRANSACTIONS

In a voluntary REC market, RECs are generally purchased either to support green marketing or to show support for renewable energy (or both). Some typical examples:

- A green energy company buys conventionally produced electricity, "bundles" it with some purchased RECs, and sells the resulting product at a premium as "renewable energy."
- An olive oil bottling plant purchases RECs in quantities sufficient to offset the non-renewable energy it consumes. It advertises to environmentally conscious consumers that its product is produced using renewable energy.
- A private citizen buys RECs to express her personal support for renewable energy.
- A municipality purchases RECs in order to participate in a voluntary greenhouse gas emissions reduction program.

Such transactions can already occur in California because the existence of a voluntary market does not depend on state laws or policies.

REGULATORY MARKET TRANSACTIONS

REC trading in a regulatory market is analogous to emissions trading programs, in which polluters have the choice of meeting regulatory mandates by reducing their own emissions or by purchasing emissions credits from others who have reduced their emissions. In the RPS context, electricity retailers are allowed to comply with the mandate either by purchasing renewable energy or by purchasing the attributes (RECs) from renewable energy production. Several other states have authorized regulatory REC markets.

Here are some examples of the kinds of transactions that can occur.

- A Massachusetts utility needs to procure renewable energy to meet that state's RPS procurement target. It is interested in purchasing 10,000 MWh of output of a biomass energy plant in Maine. However, delivery of the electricity is infeasible or perhaps simply unnecessary. The utility instead purchases 10,000 unbundled RECs from the generator, and uses these RECs to satisfy 10,000 MWh worth of its mandatory procurement target.
- The same Maine biomass generator sells its physical output – 10,000 MWh of electricity – to a utility in the state of Maine. However, since it already sold the

RECs to the Massachusetts utility, the electricity is no longer considered to have renewable attributes. Thus, although Maine also has an RPS, the Maine utility acquires no RECs in this transaction, so this purchase does not reduce that utility's RPS obligations.

- Wind power is relatively inexpensive in Texas, so a utility there procures more windpower than required under the Renewable Portfolio Standard (RPS). It sells some of its extra RECs to a small energy company in Texas that has already purchased all the electricity it needs to supply its customers, but needs RECs to meet this year's RPS procurement target.

It should be kept in mind that the kinds of REC trades that can occur in a given market depend to a large extent on how regulators define the market rules. For example, RECs can be traded across state lines in New England, but it is conceivable that California might establish rules that only allow RECs produced in state to be counted for the RPS.

CALIFORNIA'S RENEWABLE PORTFOLIO STANDARD

The basis for a California regulatory REC market would be the state's Renewable Portfolio Standard (RPS), which was enacted in 2002 and came into force in 2003.[*] Before detailing the policy issues associated with REC trading, it is necessary to lay out the structure of the RPS program.

RPS PROCUREMENT TARGETS

The California RPS statute requires electricity retailers to increase their procurement of renewably generated electricity by at least one percent each year so that 20 percent of their retail sales are procured from eligible renewable energy resources no later than December 31, 2017.

At present, the RPS procurement targets only apply to the state's large Investor Owned Utilities (IOUs). Local publicly owned utilities are exempted from the law's procurement requirements, but are required to develop their own renewable portfolio procurement plans themselves. Beginning in 2006, the law also requires compliance by other kinds of retailers, specifically community choice aggregators (CCAs), and electric service providers (ESPs).[†] ESPs are independent retailers that supply power mainly to industrial and commercial customers known as "Direct Access" customers. CCAs are a means by which cities and counties will aggregate their energy needs and provide direct access to their residents and businesses (none exist yet).

The following table shows targeted and actual procurement of the IOUs in 2004.

2004 RPS Targets and Procurement[1]

Utility	Procurement Target (MWH)	Renewable Procurement (MWh)
PG&E	9,474,755	8,591,682
SCE	12,736,000	13,246,000
SDG&E	423,336	677,966
TOTAL	22,634,091	22,514,648

As the table shows, PG&E did not meet the target in 2004. However, PG&E's compliance in 2004 was voluntary. The RPS statute does not require IOUs to comply with targets until they are creditworthy by the California Public Utilities Commission (CPUC). PG&E was deemed creditworthy in April 2004, so was not technically required to comply in 2004.

[*] SB 1078 (Sher) – California Public Utilities Code Sections 399.12-25.
[†] The statute says that the Public Utilities Commission must develop rules to "determine the manner" in which ESPs and CCAs shall participate in the RPS, but also says that they "shall be subject to the same terms and conditions applicable" to the IOUs.

According to California Energy Commission (CEC) estimates, the state would have to develop 8,469 MW of additional renewable capacity in order to meet the current RPS target of 20 percent renewable procurement by the year 2017. At the end of 2002, the latest year data is available; California had approximately 7,000 MW of installed renewable capacity.[2]

Eligible renewable energy sources are defined by statute and include biomass, solar thermal, photovoltaic, wind, geothermal, fuel cells using renewable fuels, digester gas, municipal solid waste conversion, landfill gas, ocean wave, ocean thermal, or tidal current. The renewable facility must be located in the state, or else near the border of the state. In the latter case, the first point of connection to the Western Electricity Coordinating Council (WECC) transmission system must be located within California, and the electricity must be delivered into the control area of the California Independent System Operator (ISO).[3*]

RENEWABLE PROCUREMENT PROCESS AND SUBSIDIES

Investor Owned Utilities are required to prepare renewable energy procurement plans and procure renewable energy in a competitive bidding process. Procurement plans and the awarding of contracts are subject to CPUC oversight and approval.

Bids from generators must offer renewable energy in contracts of at least 10 years duration, or less if approved by the CPUC. The ranking and awarding of bids is done on a "least cost and best-fit" basis. "Best fit" is defined as "the renewable resources that best meet the utility's energy, capacity, ancillary service, and local reliability needs."[4]

The system is designed in a way that is supposed to avoid requiring utilities to pay more for the renewable energy they procure under the RPS than they would have otherwise paid in procuring non-renewable energy. Above-market costs of the mandated renewable purchases are subsidized through "Supplemental Energy Payments" disbursed by the CEC to generators that have participated successfully in the bidding process. If available Supplemental Energy Payments are exhausted, the retailers are not required to procure any more above-market renewable energy to fulfill that year's compliance obligations.[5]

Market cost and the size of Supplemental Energy Payments are set using "market price referents" calculated by the CPUC. Market price referents are supposed to reflect the long-term market price of comparable electricity (peak or baseload) if it were purchased from conventional fossil fuel resources. The market price referents are calculated by CPUC during the bidding process but not disclosed until after the bidding occurs.

The Supplemental Energy Payments are funded by the "Public Goods Charge," a surcharge that has been levied on ratepayers of the IOUs since the 1996 electricity market

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[*] In addition, some small hydroelectric facilities and municipal solid waste combustion facilities are eligible to be counted toward calculating the "baseline" quantities of renewable energy procured, but not toward meeting the requirements for increased procurement under the RPS. Some older geothermal production is also limited to being applied to the baseline.

restructuring.[*] The Public Goods Charge amounts to about three percent of the average customer bill, and a portion of this is directed by statute into a fund for Supplemental Energy Payments. At present, about $70 million is coming into this fund every year, and about $210 million has accumulated.[6] None has been paid out yet, but that is likely to change in the near future as the procurement targets rise.

FLEXIBILITY IN COMPLIANCE

The rules established by the CPUC allow some flexibility in meeting the annual procurement targets. Excess procurement can be "banked" for meeting targets in future years. A utility can carry a deficit of up to 25 percent of its procurement target into the following year without providing any explanation. It must satisfy this deficit within three years. Annual shortfalls above 25 percent may be permitted under certain circumstances with CPUC approval.[7†]

Failure to meet the procurement targets can result in penalties of $50 for each MWh that the utility falls short of the procurement target. The penalties are capped at $25 million per utility per year.[8]

IMPLEMENTATION AND OVERSIGHT BY THE CEC AND CPUC

The California Energy Commission (CEC) was tasked with certifying eligible generators, designing and implementing a system for tracking and verifying renewable procurement, and allocating Supplemental Energy Payments from the Public Goods Charge fund (for the above-market costs of renewables). The CPUC is taking the lead in establishing rules for bidding and contracting between renewable buyers and sellers under the RPS, market price referents, and other RPS compliance rules.

At present, the CEC verifies renewable procurement by comparing generation data to electricity procurement contracts. CEC is working collaboratively with the Western Governor's Association on the development of an electronic tracking and accounting system for renewable energy transactions, including REC trading. The Western Renewable Energy Generation Information System (WREGIS) will cover 11 western states as well as parts of Canada and Mexico. The development of the WREGIS system has been subject to some delays. Although it was previously predicted that it would be ready by 2005, the CEC now says it will not be operational until late 2006 or perhaps 2007.[9]

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[*] AB 1890, the 1996 electricity restructuring bill, established the Public Goods Charge to support public interest energy research, renewable energy, and energy efficiency.

[†] Such approval requires meeting one of four conditions: (1) insufficient response to the bid solicitation; (2) contracts already executed will provide sufficient future deliveries to cover the deficits; (3) inadequate public goods funds to cover above-market contract costs; (4) seller non-performance.

ACCELERATING THE RPS

The Energy Action Plan adopted in May 2003 by the CEC, CPUC, and the Power Authority pledged that the agencies would accelerate RPS implementation to meet the 20 percent goal by 2010 instead of 2017.[10] Of the three major IOUs, two of them, Pacific Gas & Electric's (PG&E) and Southern California Edison (SCE) are on track to meet the 20 percent by 2010 goal. In fact, Southern California Edison was expected to meet its goal by 2004, six years ahead of schedule. The CEC has recommended accelerating the RPS requirements for SCE.[11]

The third IOU, San Diego Gas and Electric (SDG&E) says a REC trading program is “critical” to meeting accelerated RPS targets. The San Diego region is not rich in renewable resources, and transmission constraints limit the importation of renewable power from outside the SDG&E service territory.[12]

Last year the Legislature passed a bill making a number of changes to the RPS program, including changing the program goal to “20 percent by 2010” and instituting REC trading. That legislation (SB 1478, Sher) was vetoed. However, the Governor has endorsed the 20 percent by 2010 goal.[13]

POTENTIAL BENEFITS OF A REGULATORY MARKET

REC advocates argue that RECs offer a simple way to address both the deliverability and contract problems at the same time that they provide an expanded market to renewable generators. Most of the stakeholders in California have offered at least qualified support for the concept of allowing unbundled REC trading for RPS compliance, or at least do not oppose it outright.[*] There are differing views, however, as to whether REC trading could be implemented right now. In addition to differing views of the various policy issues, there are also disagreements among stakeholders about whether the CPUC actually has authority to implement REC trading without new legislation.

At its most general level, the case for RECs depends on the idea that markets are an efficient way to allocate resources, and that RECs would help distribute the attributes of renewable generation to those who value them the most. Those who advocate REC trading also offer several specific arguments based on California's energy situation and the challenges facing the RPS program.

MITIGATING TRANSMISSION AND DELIVERABILITY PROBLEMS

The RPS program envisions the creation of a great deal of new renewable generating capacity in the state, but this raises the problem of how to connect all the new facilities to the grid. Furthermore, once a facility is connected, congestion of the transmission system means one cannot always reliably and cheaply move electricity from one region to another. State energy policy makers recognize that California has under-invested in transmission, presenting a "significant barrier to accessing renewable energy resources."[14]

According to the CEC, the **southern** California region has the greatest potential for development of new renewable energy, particularly wind energy in the Tehachapi area and geothermal energy near the Salton Sea. However, this same region is also seriously lacking in transmission infrastructure.[15]

Renewable energy presents several challenges for transmission planning. It is usually generated in remote areas far from population centers. It is also produced in small increments by many independent developers, and it is difficult to predict the amount that will be generated in the future in a given locale with enough certainty to plan construction of new transmission lines.[16]

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[*] Among those who voiced support for moving forward with REC trading in CPUC proceedings: SDG&E, PG&E, the Alliance for Retail Energy Markets, the Independent Energy Producers Association, The City and County of San Francisco, California Wind Energy Association, and the Center for Energy Efficiency and Renewable Technologies. The Green Power Institute endorsed the concept but advised the CPUC to defer to the Legislature before initiating a new program. Some parties voiced relatively more caution, emphasizing the potential pitfalls of REC trading and/or stressing the view that current law did not authorize it. These included Clean Power Markets, Southern California Edison, and The Utility Reform Network (TURN). TURN voiced the strongest case objecting to unbundled REC trading. Solar advocates did not oppose the REC concept, but placed a great deal of emphasis on specific questions relating to how RECs would affect the solar industry. These included questions about distributed generation discussed elsewhere in this report.

The current RPS structure may actually create disincentives to add the needed transmission capacity. The RPS bidding rules require that transmission costs be reflected in the bids of energy generators competing for RPS contracts. Several stakeholders argued before the CPUC that this could "create a classic 'free rider' problem – every developer will prefer to build the second facility in a new resource area, and take advantage of the investment made by a developer that is willing and able to finance the entire upgrade on their own. In this situation, potentially everyone waits, and no one builds."[17]

RECs would allow renewable attributes to go where they are needed without requiring that the electricity go with them. REC trading will not cause needed transmission facilities to be built any faster, and California will still need to improve its transmission infrastructure. However, REC trading would likely mitigate the effects of transmission constraints on RPS compliance costs. San Diego Gas & Electric Company has been a particularly strong advocate of this view because of the limited renewable energy in that region.[18] PG&E also supports REC trading, which could allow it to use low-cost renewable energy produced in Southern California or perhaps other states, to meet its needs.[19]

ADDRESSING CONTRACTING CONSTRAINTS OF NON-IOU RETAILERS

At present, only the large IOUs are required to meet procurement targets under the RPS, but this is likely to change soon. The CPUC and the CEC are supposed to develop procurement requirements for the other retailers, including Electric Service Providers (ESPs) and Community Choice Aggregators (CCAs).

ESPs are independent retailers that supply power to industrial and commercial customers known as "Direct Access" customers. There are currently 18 ESPs registered with the CPUC.[20] However, it appears that fewer than half of them are still actively doing business in California at present.[21] ESPs currently serve about 13 percent of California's electrical load.[22*]

ESPs serve smaller loads and fewer customers than large utilities, so the amount of electrical load served by an individual ESP can change significantly from year to year. They argue it is infeasible for them to procure renewable energy using the long-term contracts now required by the RPS for IOUs. While large utilities also assume some risk in taking on long-term contracts, they serve far more customers, so the risk to their overall portfolio posed by a miscalculation on any individual contract is less severe.

RECs offer an alternative to long-term contracts for electricity. Because RECs are readily traded in short-term markets, they offer one way for non-utility retailers to match the terms of their energy purchases to the terms of their supply obligations to the

[*] With the 1996 restructuring, commercial and industrial end-use customers were permitted to choose whether to purchase service from their public utility or become "Direct Access" customers of an ESP. Direct access was suspended in 2001 during the electricity crisis, but some contracts that existed before then continue to be in force.

companies that buy power from them. For example, if a retailer's customer wants a one-year contract for electricity, the retailer can match that to a purchase of an appropriate quantity of RECs to satisfy the RPS mandate.

Similar issues might also arise for CCAs, but this is not clearly the case. The CCA program allows cities and counties to aggregate their energy needs and provide direct access to their residents and businesses. Although there are CCAs under development, none have yet entered the market. CCA's may be better able to predict their loads than ESPs, and some are considering ownership of renewable generation.[23]

NEW FLEXIBILITY AND OPPORTUNITIES FOR GENERATORS

Renewable projects are often financed based on contracts to sell their generation output. The appropriate size of a project, however, may exceed the contract amount for various reasons, such as the area's resource potential or the optimal size of a turbine. For example, if the ideal size of a new wind facility was 200 MW, but the project had a long-term contract with a utility to provide 150 MW, then RECs would provide a new market in which to earn revenues from the extra capacity.

It has already been noted how REC trading can provide renewable generators with access to geographically remote markets. Another potential benefit is that RECs can reduce the "temporal mismatch" between generation and demand.[24] The demand for energy varies with the time of day and season, and peak demand does not necessarily coincide with peak renewable production. Renewable generators often depend on forces such as wind and sun that are inherently variable or intermittent. Furthermore, energy is difficult to store. However, time of delivery ceases to be an issue if the product is unbundled RECs rather than RECs plus electricity.

POLICY ISSUES AND QUESTIONS

REC trading raises a number of policy issues and questions. In this section I will review the policy issues that have emerged in CPUC proceedings and other discussions.

Who should address these issues is not entirely clear. Some stakeholders believe that REC trading could be implemented by the CPUC and CEC without any new legislation, but other stakeholders disagree. The CPUC itself seems to believe that it could adopt REC trading, but decided in 2003 that it was premature to do so at that time.[25]

FULFILLING THE GOALS OF THE RPS

In considering REC trading, it is important to bear in mind the legislative intent of the RPS program. The CPUC has indicated that it would not attempt to implement REC trading unless there was a "clear showing" that a REC trading system would be consistent with the specific goals of the RPS.[26]

The legislative intent language of SB 1078 established the following goals for the RPS:[27]

- Increasing the diversity and reliability of the energy mix and reducing reliance on imported fuels,
- Promoting stable electricity prices,
- Protecting public health,
- Improving environmental quality, and
- Stimulating sustainable economic development and new employment opportunities.

In addition to these goals, the CPUC said it would need to ensure that REC trading would not "create or exacerbate environmental justice problems, and would not dilute the environmental benefits provided by renewable generation." The CPUC also noted that a REC trading system would have to be carefully designed to avoid market manipulation.[28]

DEFINING WHAT IS INCLUDED IN A REC

A REC can be defined in varying ways. The CPUC has noted that "The utility must know what renewable attributes it is acquiring … Similarly, renewable generators need to know exactly what attributes they have sold to the utilities."[29]

The idea that a REC incorporates environmental attributes, as well as resource type, location, and vintage (when it was produced), has been widely adopted in other states. This means these other attributes cannot be separately unbundled and traded.[30]

For example, suppose a renewable generator produces 1 MWh of electricity, which it sells, along with the associated REC, to a utility, which in turn applies the REC to meeting the RPS. Can the generator then sell the air emissions reduction associated with that one MWh to help a manufacturer's green marketing program? The CPUC's current view is that a REC would incorporate all of the environmental attributes of the purchased resource.[31*] This would mean that any emissions reduction attribute, for example, could not be detached from the "renewableness" of the energy and sold separately.

The CPUC has left open the possibility that various environmental attributes could eventually be unbundled and traded separately in the future, and intends to examine the issue further in coordination with the CEC.[32]

PREVENTING DOUBLE-COUNTING

There are broad consensuses that clear rules and a tracking system are necessary to define and prevent double-counting. There is no reason in principle why a tradable REC should not change hands multiple times. However, in a regulatory market, the rules would likely require the REC to be "retired" and not be re-sellable once it had been counted toward a retailer's compliance with its RPS obligations.

Another key feature of REC trading is that a given quantity of electricity ceases to be considered renewable energy once its RECs have been unbundled and sold separately. Here are some examples of what would be prohibited as double-counting:

- A utility buys a unit of renewable energy and applies it toward meeting its RPS; and then sells a REC associated with the same unit of generation to another company to meet the RPS in another state.
- An Electric Service Provider purchases a unit of renewable energy and applies the REC toward meeting the RPS; and then re-sells the associated electricity as renewable energy in a green power program.
- A utility purchases a unit of renewable energy, sells the REC, and then claims the renewable energy on its power content label.
- A generator sells RECs to a utility for RPS compliance; and then sells RECs for the same generation to a shoe manufacturer in a voluntary REC market transaction. Based on this purchase, the shoe manufacturer then claims in its advertising that it uses renewable energy.

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[*] In the standard procurement contract terms and conditions adopted by the CPUC for use in the RPS, "environmental attributes" are defined as "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 … [and] the reporting rights to these avoided emissions such as Green Tag Reporting Rights …" (California Public Utilities Commission, "Appendix A: Renewable Portfolio Standard, Standard Contract Terms and Conditions," A-2, in "Opinion Adopting Standard Contract Terms and Conditions," Decision 04-06-014 June 9, 2004).

In one of the examples of double-counting, a retailer purchased a unit of renewable energy, applied the REC toward the RPS, and then re-sold the associated electricity in a green power program. It is important to understand that the violation here is not re-marketing the electricity; it is re-marketing the electricity *as if it were still renewable energy*. Once the RECs have been applied toward RPS compliance, the energy has in effect been stripped of any renewable attributes. There is, however, no double-counting if the utility re-markets the electricity as conventional ("brown") power, with no marketing claims or price premiums based on renewable attributes it no longer possesses.

Other states with REC trading have electronic tracking and accounting systems that assign each REC an individual identity number. Such a system helps regulators to keep track of who owns each REC and whether the REC qualifies for that state's RPS program. However, not even a robust tracking system can provide total assurance against double-counting, because it will always be possible for a REC tracked within that system to also be sold outside that system's purview. Penalties and the possibility of auditing might help to deter such abuses.

The California Energy Commission (CEC) is leading the development of an electronic tracking system for California and 10 other western states, known as the Western Renewable Energy Generation Information System (WREGIS). However, according to the CEC, it may not be operational until 2007.

Eligibility of Out-of-State Renewable Generation

One of the benefits of RECs is the elimination of geographic barriers. However, the desirability of allowing unbundled RECs to be freely brought in from other states has been a lively point of contention in recent CPUC proceedings.

The Utility Reform Network (TURN), a consumer advocacy group, asserted that if there is unfettered REC trading across state lines, "the expected consequences can be predicted with a high degree of confidence. Since the least expensive renewable generation in the WECC is wind power sited in states such as Wyoming and Montana, development will occur in those states with RECs being sold at prices far below the level needed to support the development of renewable generation located in California."[33]

The CPUC has acknowledged that allowing tradable RECs from outside of California could conflict with the goals of SB 1078: "if a utility were to meet its RPS requirements by purchasing RECs from generators located in other states, that would not appear to provide California with the economic development, job creation, environmental, and other benefits anticipated by SB 1078." "Further, to the extent that the underlying power is not deliverable into California, public health and environmental benefits anticipated by the RPS statute may also not be realized."[34]

On the other hand, as REC trading advocates point out, access to out-of-state RECs at low cost would reduce compliance costs for the RPS (which in turn could have economic benefits for the state). In addition, an abundant supply of RECs will be necessary for a well-functioning market with stable REC prices.[35] Certain goals might be furthered by renewable development regardless of whether it happens in California or in other states – for example, reduction of greenhouse gas emissions and reduced overseas imports of fossil fuels.

At present, renewable energy for RPS compliance can be procured from out of state, if the facility is near the border, connects to the western regional transmission system within California, and delivers the electricity within California. Allowing out-of-state RECs within these limitations would preserve the status quo with respect to importing renewable attributes from out of state. Requiring deliverability of the electricity assures that at least some of the intended benefits of the RPS are realized, because the out-of-state renewable capacity actually contributes to California's electricity supply. Even though it is generated out of state, the electricity will still be available as a hedge against fossil fuel price rises and could displace some polluting generation within California.

To sum up, the question of whether the goals of the RPS are undermined by out-of-state RECs depends in part on which goal we are talking about, as well as the rules regarding such transactions. The following table summarizes this.

In-State Versus Out-of-State Renewable Benefits

→ **Decreasing Restrictiveness**

Strict In-State Requirement	In-State Interconnection or Delivery Requirement	Unbundled From Within Region OK With Delivery to the Region	Unbundled From Out of State Possible W/O Delivery Reqmts
HI			
MN			
AZ	AZ		
	CA		
	CO		
	NV		
	NM		
	NY		
	TX		
	WI		
		MA	
		ME	
		NJ	
		PA	
		RI	
		CT	CT
			DC
			MD

Notes:
(1) All of the above states have or will have REC trading except California, Hawaii and Minnesota.
(2) Arizona, Colorado, and New Mexico encourage in-state renewables by weighting in-state RECs or energy more favorably.
(3) AZ and CT appear in more than one column because their rules treat some categories of renewable generation differently from others.

Other policies could be used to encourage in-state development of renewables without completely barring out-of-state RECs. For example, Supplemental Energy Payments could be enhanced for in-state RECs in comparison to out-of-state RECs. Other renewable energy subsidies provided by the state might also be tied to some guarantee that a certain portion of the RECs will be sold in-state.

State RPS laws that explicitly exclude RECs from out-of-state sources might run afoul of the U.S. Constitution's Commerce Clause, as well as the North American Free Trade Agreement (NAFTA). However, there may be ways to structure the program to favor in-state RECs while reducing or eliminating such legal problems. It appears that state requirements for the RECs to be delivered with electricity to the state border would not conflict with the Commerce Clause.[36] Another possible solution, according to one analysis, would be conditioning RPS eligibility on the generator providing benefits to the state.[37]

ASSIGNING REC PROPERTY RIGHTS

Contracts for the purchase of electricity from renewable generators usually now acknowledge the creation of RECs and explicitly state whether RECs have been purchased or not.[38] However, older contracts are often silent on this, raising ambiguities about ownership of tradable RECs. Much of the debate has centered around two categories of contract: Public Utility Regulatory Policy Act of 1978 (PURPA) contracts and distributed generation/net metering.

Net metering is an incentive provided for distributed generators. Distributed generators are utility customers who produce small amounts of power locally near the point of use. Net metering allows these customers to be credited for electricity that they generate on site in excess of their own electricity consumption. In CPUC proceedings, the question has arisen of whether the RECs produced by distributed generation should be the property of the customer or the utility.

Utility interests have argued that because distributed generation is often subsidized by ratepayers, the utility should be able to apply all of the associated RECs toward their RPS compliance. Advocates of distributed generators dispute the extent to which they have been subsidized and point out the benefits their generation provides to utilities and ratepayers. They argue that if RECs are going to become tradable, then distributed generators should be able to keep and sell them.

CPUC has issued a draft decision stating that for the time being, the RECs from distributed generation would go to the utilities that procured their electricity. Their reasoning seems to be that since RECs cannot be unbundled under the RPS, the utilities acquired the RECs when they acquire the electricity. However, the CPUC also left open the question of whether this decision might be revisited if unbundled REC trading was allowed in the future.[39]

With respect to the ratepayer subsidies, the CPUC noted that these are typically for equipment and capital costs, while RECs represent credit for generation. Thus, "it does not appear readily possible to determine what portion of a REC from a given [distributed generation] facility was actually supported by ratepayer subsidies." CPUC suggested that in the future the subsidies could be clarified to spell out precisely what component of the anticipated benefits is being subsidized.[40]

A similar debate is ongoing regarding Power Purchase Agreements (PPA) under the Public Utility Regulatory Policy Act of 1978 (PURPA). PURPA requires utilities to buy power from independent generators, known as Qualifying Facilities (QFs). Prices are based on utilities' "avoided costs," that is, what they would have otherwise had to spend to generate or procure the power. Older PURPA contracts do not anticipate RECs, so the question now arises of whether the utilities acquired the REC property rights. As in the distributed generation dispute, the argument frequently revolves around the amount and nature of subsidies provided to the renewable generators by the utilities and their ratepayers, and what effect, if any, this should have on the REC property rights.[41]

In 2003, the Federal Energy Regulatory Commission (FERC) ruled that RECs are not automatically conveyed with avoided-cost-based PPAs. However, FERC also ruled that states have broad discretion to define such property rights.[42] The CPUC has not yet taken a position on who owns the property rights associated with these RECs.[43]

LONG-TERM CONTRACTS VERSUS SPOT MARKETS: IMPLICATIONS FOR RENEWABLE PROJECT FINANCING

Some commenters raise the question of whether RECs might undermine renewable energy development by reducing the incentives for electricity sellers to enter into long-term contracts for renewable supplies. New renewable projects are capital-intensive, and long-term procurement contracts are usually a prerequisite for the developers to obtain financing.[44] An RPS program that relied too heavily on unbundled RECs spot markets could fail to produce sufficient investment in the required new generating capacity.

It should be noted that these concerns do not seem to be widespread in the renewable energy industry itself. Renewable industry representatives acknowledge that long-term contracts are key to financing renewable projects. But the ones who have participated in the CPUC proceedings were supportive of REC trading. They tend to think that RECs will provide additional markets and revenue streams that will help to spur development.[45]

There are both regulatory and market tools that could help assure that renewable procurement does not become dominated by short-term transactions. On the regulatory side, the RPS could continue to require that some portion of utility renewable procurement is done through long-term power purchase contracts. Such a requirement might not be feasible for ESPs. But utilities serve most of the load in the state, so it should be possible to incorporate more flexibility without going to a system that relies entirely on short-term transactions.

Markets will likely also find their own ways to incorporate RECs into contracts and financing arrangements. A trader for a major wholesale energy broker who was contacted for this research said that he is currently structuring deals in which investors back renewable projects based in part on the expectation of REC revenues. This is occurring in markets such as Massachusetts where REC prices are high. Although the long-term returns from RECs are inherently uncertain, they are currently high, and the downside risk is limited by the more predictable returns from selling the electricity.[46]

The director of Green-e, a nonprofit REC certification program, described a form of contract that is already being used in which buyers and sellers hedge the risks associated with RECs, called "contracting for differences." In these contracts, which run 5-10 years, a buyer agrees to pay up to a certain price for RECs, say for example $40/MWh. The generator sells the electricity separately, and the price received for the electricity is subtracted from this limit, with the REC buyer paying the difference. This assures the renewable generator a certain price for the combination of RECs and energy, and hedges the REC buyer against future REC price increases.[47*]

With REC markets still somewhat new and fragmented, it can be difficult to project future REC prices and estimate risks and returns associated with long-term REC contracts.[48] If current trends continue, REC markets should grow and mature, and RECs will be able to play an increasing role in project finance.

REC Scarcity, Price Stability and Price Manipulation

A closely related set of concerns has to do with potential price volatility and market manipulation. Again, the issue is the potential negative effects should the RPS program rely too heavily on REC spot markets.

To begin with, if the RPS requirements were met mainly through REC spot markets rather than long-term investment in new renewable generation, then one of the purposes of the RPS would likely be undermined: providing the state's consumers with a diversity of energy sources that hedges against future spikes in fossil fuel prices. Second, high REC prices caused by scarcity or market manipulation could themselves drive up costs.[49] The Utility Reform Network (TURN) points to examples such as price spikes in the Southern California RECLAIM market for emissions credits, as well as the experience with high REC prices in Massachusetts (which will be discussed more later).

As just noted, advocates of RECs argue in response that nothing in the nature of RECs requires that they be sold only in short-term transactions. Some of them argue that if renewable scarcity and REC price spikes are a concern, that will actually provide an incentive for utilities to secure long-term contracts that include RECs as a hedge against

[*] If the price specified in the contract for differences was $40/MWh, and if the electricity were subsequently sold for $25/MWh, the REC buyer must pay the generator $15/MWh for the RECs it bought ($40 minus $25). If the price of electricity reached $45/MWh, the generator would owe the REC buyer $5 per REC. In this way, the generator is guaranteed that the combination of RECs and electricity it generates will fetch a net $40/MWh. The REC buyer knows it will pay less than $40/MWh for the RECs.

volatile spot REC prices.[50] In addition, regulators could encourage or direct regulated utilities to maintain a portfolio of short-, mid-, and long-term renewable purchases, either in the form of REC or power purchase contracts.

Ensuring that the market produces enough RECs will involve some additional policy tradeoffs. One has already been highlighted – the tradeoff between a permissive policy on out-of-state RECs to maximize market liquidity versus a restrictive policy to maximize certain in-state renewable energy benefits.[51] Liberal rules on banking RECs for future use increases their value. However, these could also limit the market's liquidity and encourage hoarding and market manipulation.

Supplemental Energy Payments

Investor-owned utilities comply with the current RPS requirements through long-term contracts procured in a process overseen by the California Public Utilities Commission (CPUC). Generators who win utility contracts are eligible for Supplemental Energy Payments from the California Energy Commission if the renewable energy prices in the contracts are higher than the market energy price referents established by the CPUC. Utilities are not obliged to purchase renewable generation to satisfy RPS requirements once the payments for above-market prices are exhausted for that year.

The Supplemental Energy Payments are funded by the "Public Goods Charge," a surcharge that has been levied on ratepayers of the IOUs since the 1996 electricity market restructuring. So far, none of the utility renewable energy purchases under the RPS have required Supplemental Energy Payments. However, this is likely to change in the future as RPS requirements increase and new renewable resources must be developed to meet them.

ESPs argue that REC purchases made to comply with RPS obligations should be eligible for supplemental payments.[52] Utilities would also want to claim Supplemental Energy Payments if they purchase RECs for RPS compliance. CPUC oversight would be necessary, which could make an unwieldy program even more difficult to administer. ESPs and CCAs are not currently subject to CPUC oversight, so this could greatly expand the scope of CPUC oversight over electricity markets.

It is not clear how regulators would determine when RECs are eligible for such payments or how much the payments should be. The ESPs sometimes argue that RECs should be equated with the above-market costs of renewable energy. However, simply reimbursing retailers for REC purchases would provide no incentive for buyers to seek, or sellers to offer, low-cost RECs. Without such incentives, prices might be excessive and public funds would not go as far as they should.

PG&E has recommended establishing a process for determining when a retailer's REC and electricity purchases during a given compliance period are, in aggregate, greater than what it would have cost to meet its customers needs at market energy prices.[53] The current system is already complex, so working out how this would be accomplished may also be a complex task.

One possible approach to simplifying the oversight of Supplemental Energy Payments, at least in the short run, would be to distribute each year's available funding to ESPs and CCAs based on retailers' *pro rata* share of statewide electricity sales.[54] That way, it would not be necessary for the regulators to verify each individual REC transaction and determine its eligibility for a subsidy. The onus of controlling costs would fall on the retailers.

Another possible approach to ESP and REC procurement would be to designate or create some new agent that procures RECs on behalf of ESPs and CCAs, perhaps using Supplemental Energy Payment funds to procure RECs and/or renewable energy.

Ultimately the state might want to revisit and reconsider how it uses the Public Goods Charge for supporting IOU procurement as well. For example, the state might distribute funds directly to renewable generators in a competitive process, in which the winners are those who can provide renewable energy to the market with the smallest subsidy. This might be more effective in helping to bring new renewable capacity online. However, such an approach might be resisted by electricity retailers who view the Supplemental Energy Payments mainly as a means of ensuring that their RPS compliance costs will not exceed the market costs of procuring electricity.

ENVIRONMENTAL JUSTICE

Emissions cap-and-trade programs are sometimes criticized on the grounds of "environmental justice" or "environmental equity." Pollution trading programs bring down the overall amount of pollution, but some polluters may purchase credits rather than reduce emissions, and nearby populations will suffer the environmental and health impacts.

A similar argument is sometimes advanced regarding REC trading: some locales could benefit environmentally and economically from more renewable energy production, while elsewhere the mix of local generation would not change.[55]

It is difficult, however, to directly link REC trading policies to environmental justice issues. Renewable energy is likely to be generated where the renewable resources, such as wind or geothermal energy, are abundant, regardless of whether there is REC trading.

To take one example sometimes cited, PG&E runs an older gas-fueled power plant at Hunter's Point in San Francisco. If that plant were closed, low-income neighborhoods in the vicinity would arguably have cleaner air. If PG&E were forced to procure more renewable energy, it might have some incentive to retire that plant and replace it with cleaner energy sources. If, on the other hand, it could comply with the RPS by purchasing RECs from southern California, that incentive would perhaps be removed.

In most cases the actual situation will probably be more complex, however. For example, a power plant such as the one at Hunter's Point provides benefits of system reliability and adds to the capacity to meet local peak load demand. Whether or not RECs can be purchased for RPS compliance may have little effect on how soon a utility decides to shutter such a power plant.

In general, it seems infeasible to assure that urban and rural areas share equally in the air quality benefits of renewable energy. In an ideal world all regions would reap the same benefits from the RPS. But inevitably there will be some geographic scale at which inequities appear – some areas will import renewable energy and "export" the associated environmental benefits. Policy makers could choose to place geographic restrictions on the movements of RECs, but if these restrictions are too fine-grained, they may eliminate the benefits RECs were supposed to provide.

REC TRADING IN OTHER STATES

STATES WITH RPS AND REC TRADING PROGRAMS

According to the most recent available reviews, there are 18 states (plus the District of Columbia) in which there are RPS programs with mandatory targets. Most of them (13 states and the District of Columbia) have approved regulatory REC markets (although REC trading has not been implemented yet in all of them). All but three of the states with ESPs have approved REC trading.

RPS Trading and ESPs by State[56]

State	Have Active ESPs	Have or Will Have REC Trading
California	✓	
Arizona	✓	
New York	✓	
Connecticut	✓	✓
District of Columbia	✓	✓
Massachusetts	✓	✓
Maryland	✓	✓
Maine	✓	✓
New Jersey	✓	✓
Pennsylvania	✓	✓
Rhode Island	✓	✓
Texas	✓	✓
Colorado		✓
Montana		✓
Nevada		✓
New Mexico		✓
Wisconsin		✓
Hawaii		
Minnesota		

A recent review of state programs found that RECs have been most actively traded for compliance in Texas, Massachusetts, Connecticut, and Maine.[57] The Texas REC trading program has been called the most successful such program in the country.[58]

TRADING IN REGULATORY MARKETS

There are no readily available estimates of the numbers of unbundled RECs traded in the U.S. Tracking of trades is fragmented between different state and regional systems. Nor do the tracking systems that record REC transactions distinguish bundled from unbundled RECs.[59]

The size of compliance markets has an upper limit determined by the amount of renewable energy that must be procured to meet the various state RPS requirements. The National Renewable Energy Laboratory (NREL) recently published a study estimating that existing state RPS requirements in states with REC trading created a need for 12.6 million MWh worth of RECs in 2004. Some portion of this would presumably be supplied by unbundled RECs, but NREL did not attempt to estimate how much.[60]

NREL found 2004 REC prices in compliance markets ranging from a low of $0.65/MWh in Maine (where RPS-qualified renewables are ample to meet RPS requirements) to $49/MWh in Massachusetts (where they are in short supply).[61]

REC Prices in Selected Compliance Markets[62]

State	2004 REC Prices ($/MWh)	Noncompliance Penalty ($/MWh)
Maine	0.65-0.70	N/A
Texas	11-15	50
Connecticut	35-48	55
New Jersey	4.25-7.50	50
Massachusetts	40-49	51

The prices in Massachusetts are unusually high. As will be discussed in more detail later, Massachusetts electricity markets have not provided sufficient incentives for the development of renewable energy, leading to REC shortages and high prices.

Compliance penalties set by regulators generally establish an upper bound on REC prices, because a regulated entity has no incentive to buy RECs once REC prices are equal to the penalty.

TRADING IN VOLUNTARY REC MARKETS

According to the same NREL study, unbundled REC sales in voluntary markets "have grown significantly in recent years."[63] According to NREL, there are now more than 30 entities marketing RECs nationwide. These include brokers and energy companies, selling renewable energy and RECs to both retail and wholesale markets.[64]

There is a lack of comprehensive data on the size of voluntary markets. The above-cited NREL study based its conclusion about the growth of these markets on discussions with REC marketers. It appears that the best source of hard data on voluntary REC trading comes from a California-based nonprofit organization, Green-e, that certifies RECs for trading.

In 2003, purchases of RECs certified by Green-e, totaled 1.83 million MWh. This represented a 12-fold increase over the previous year. Green-e certified 18 REC marketers selling to 3,170 customers. While most of the purchasers were retail residential buyers, the great majority of the purchased RECs were used by utilities and ESPs in retail green power programs.[65] Green-e estimates that it certifies 52 percent of all the RECs sold in voluntary retail markets in the U.S. Unfortunately, the organization does not have an estimate of its share of the larger wholesale market.[66] Green-e reports that their program certified 240,000 MWh worth of RECs from renewable generation in California in 2003.[67]

REC TRACKING SYSTEMS

Electronic tracking systems are coming into widespread use. An electronic tracking system assigns each REC a unique identifying number and records its characteristics (for example, where it was produced and what type of renewable technology produced it). Buyers and sellers of RECs have electronic accounts that record the RECs they own at a given time, rather like bank accounts. It is possible, albeit more labor-intensive, to track RECs manually without an electronic system.

As of 2004, electronic REC tracking systems were in place in New England, Texas, and Wisconsin.[68] The following table shows the status of tracking systems in states that have authorized REC trading.

Tracking Systems in States with REC Trading[69]

States With REC Trading (and year of first RPS obligations)	Electronic Tracking System	Electronic Tracking System in Development	Manual Tracking System in Place
Wisconsin (2001)	✓		
Connecticut (200)	✓		
Massachusetts (2003)	✓		
Maine (2000)	✓		
Rhode Island (2007)	✓		
Texas (2002)	✓		
Montana (2008)		✓	
Colorado (2007)		✓	
District of Columbia 92007)		✓	
Maryland (2006)		✓	
New Jersey (2001)		✓	
Pennsylvania (2007)		✓	
Nevada (2003)		✓	✓
New Mexico (2006)		✓	✓

POLICIES IN DIFFERENT STATES

This section discusses approaches taken in various states to some of the policy issues already mentioned.

Limitations on Trading RECs Across State Lines

States have taken varying approaches to the question of making renewable energy from out-of-state eligible for their RPS. The table below arranges the states with RPS policies according to how restrictive their out-of-state generation eligibility rules are.

A strict in-state requirement means that the state does not allow out-of-state generation or RECs to count toward compliance. An interconnection or delivery requirement means the state requires RECs to be delivered into the state bundled with electricity, or requires that the first point of interconnection for the facility be within the state's grid. Some states such as those in New England enforce delivery requirements on a regional basis.

RPS Eligibility Restrictions[70]

Strict In-Sate Requirement	In-State Interconnection or Delivery Requirement	Unbundled From Within Region OK with Deliver to the Region	Unbandled From Out of State Possible W/O Delivery Remts.
HI			
MN			
AZ	AZ		
	CA		
	CO		
	NV		
	NM		
	NY		
	TX		
	WI		
		MA	
		ME	
		NJ	
		PA	
		RI	
		CT	CT
			DC
			MD

Supplemental Energy Payments

California's Supplemental Energy Payments appear to be an unusual arrangement – no other state's RPS program has such payments.[71] The closest parallel appears to be Arizona. As in California, Arizona uses funds from charges imposed on ratepayers. However, the funds go to the utilities rather than the generators. Once the funds are used up, the utilities do not have to do any more RPS procurement that year. Arizona does not allow RECs for RPS compliance.[72]

Policies on Renewable Procurement and Contracts

Most states do not enforce specific rules in their RPS programs requiring the use of long-term renewable electricity procurement contracts, but some do.[73] For example, in Connecticut, utilities are required to procure at least 100 megawatts of power from renewable energy sources through long-term contracts. The power must come from generators that receive funding from the state's Renewable Energy Investment Fund. Ratepayers may be required to pay a premium for these contracts of up to 5.5 cents per kilowatt-hour.[74] In Colorado, utility procurement of renewable energy for the RPS must be in 20-year contracts, but utilities are still free to forego long-term power contracts and purchase RECs on the market if they choose. In addition, the 20-year contracts can be made shorter at the request of the generators.[75]

Central Procurement

No other state was identified in which a central entity procured renewable energy on behalf of the regulated retailers. In Massachusetts, a state program procures RECs in long-term contracts in order to help stimulate renewable energy development.

New York does have something commonly referred to as a central procurement process for its RPS, run out of the New York State Energy Research and Development Authority (NYSERDA). NYSERDA uses funds from a surcharge on utility ratepayers to fund the program. It enters into contracts with renewable generators, providing production incentives for them to sell and deliver energy into the New York wholesale market. The resulting production satisfies the RPS requirements on behalf of the regulated retailers, and they are not required to do any procurement for the RPS themselves. The generators give up the right to sell the associated RECs, so the NYSERDA program can be viewed as in effect a central REC procurement system. New York is unique in this incentive-based approach.[76]

Distributed Generation/PURPA Ownership Issues

The question of property rights for RECs under older Public Utility Reulatory Policy Act (PURPA) and distributed generation contracts appears to be an open question in most other states, with a few exceptions. In Maine, the Public Utilities Commission has ruled that utilities purchasing power from independent generators also get ownership of the RECs if the contract leaves the question open.[77] In New Jersey, where the RPS procurement targets include specific targets for solar energy, distributed photovoltaic generators are allowed to keep and sell the RECs from their generation.[78] However, in the case of utility power purchase agreements, RECs will be transferred to the utilities for the first two years of the program.[79]

TWO CASE STUDIES: MASSACHUSETTS AND TEXAS

The cases of Massachusetts and Texas provide two contrasting examples of the results of introducing REC trading for RPS compliance.

In Massachusetts, unbundled RECs have become the primary means by which retailers comply with the state RPS. In fact, long-term power purchase contracts for renewable electricity have become so unusual that it has impaired the ability of developers to finance new renewable projects. There is currently a shortage of RECs, prices are high, and it is an open question whether the RPS as currently structured will stimulate enough new renewable energy development.

However, the state has introduced some novel policies to help address the lack of long-term contracting. In addition, there is much new renewable capacity in the development pipeline, giving some credence to hopes that markets are responding appropriately, if slowly, to the high REC prices. However, many of these new projects will likely face substantial hurdles in the siting process.

Texas is often cited as a more successful example of a well-functioning market. REC prices have been higher than expected, but are still much lower than in Massachusetts. The Texas RPS has been credited with helping to spur rapid growth in wind power development. Although unbundled RECs have made the Texas RPS more flexible, the bulk of the renewable energy procurement is still occurring through long-term contracts for electricity and RECs bundled together.

MASSACHUSETTS

Massachusetts is part of a regional New England electricity market in which several states have Renewable Portfolio Standards and trade RECs across state lines: Massachusetts, Connecticut, Maine, and Rhode Island. The New England Power Pool (NEPOOL) provides the region's generation and transmission system for six states – the above plus New Hampshire and Vermont. The NEPOOL's Generation Information System (NEPOOL-GIS) tracks RECs throughout the region, as well as fuel mix and emissions information for other regulatory programs.[80]

Massachusetts' RPS and REC Market Rules

The Massachusetts RPS statute was established by statute in 1997. It requires that all retail electricity suppliers include a minimum percentage from "new renewable" energy sources in their supply mix. The Massachusetts RPS procurement obligations began at one percent in 2003, and rise by a half percent each year through 2009, reaching four percent. After 2009 they will increase by one percent a year.[81]

Eligible renewable sources include solar, wind, ocean thermal, wave or tidal; fuel cells using a renewable fuel; landfill gas; anaerobic digester gas; and low-emission biomass power conversion technologies. The unit must have started generating after the end of 1997. Pre-1998 generators that generate more than they did historically during 1995-1997 can count the excess generation as "new."[82]

RECs and renewable energy from other states in New England can be used in the Massachusetts RPS. Credits from outside of New England must be accompanied by electricity transmitted into the New England grid.[83]

Retailers who fail to meet their targets must make Alternative Compliance Payments. These payments act both to enforce compliance and to set a price ceiling for RECs. The payments were initially set at $50 per MWh in 2003, and increase annually with the Consumer Price Index.[84]

If a retailer owns more RECs than it needs, it can bank them toward compliance during the following two years. However, in order to protect price stability, the amount that can be banked is limited to no more than 30 percent of the year's compliance obligation.[85]

Massachusetts' Market Experience So Far

A relative scarcity of renewable generation in Massachusetts has led to a tight supply for RECs and high prices, sometimes nearing the upper limit set by noncompliance penalties. Some RECs sold for $49/MWh in 2004, just below the $51/MWh noncompliance penalty.[86*]

2003 was the first year in which retail suppliers had to meet the RPS. Renewable resources within the state accounted for 40 percent of the energy used to meet the requirement. The largest single share of 2003 renewable energy came from nine landfill methane plants located in four states. The second largest was biomass, concentrated in Maine. Third was anaerobic digester gas.[87]

In 2003, there was a gap of 194,232 MWh between the RPS obligations and the number MWh of qualifying renewable credits procured. Much of the gap was covered by "Early Compliance Certificates" issued for 2002 generation (anticipating a shortfall, the rules allowed generation from 2002 to be applied to 2003 RPS obligations). One electricity supplier had to cover a gap of 181 MWh with Alternative Compliance Payments. With Early Compliance Certificates no longer available beyond 2003, the Alternative Compliance Payments are expected to be much larger. Regulators were expecting 301,000 MWh worth of Alternative Compliance Payments to be made in 2004 (about $15.5 million worth at the price of $51.41 per MWh).[88]

Siting difficulties have contributed to the shortage of renewable resources in the region. Builders of new facilities often face daunting regulatory hurdles as well as local "**NIMBY**" opposition.[89] For example, Massachusetts' 420 megawatt Cape Wind project, which would be the first offshore wind installation in the country, has encountered significant local opposition and the environmental review process has been arduous. Construction is supposed to begin in 2006.[90]

Another problem in Massachusetts is that electricity procurement is not structured in a way that encourages long-term procurement contracts. Without such contracts, it has

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[*] One megawatt equals 1000 kilowatts. So a price of $49/MWh is equivalent to $0.049/kWh.

been more difficult for renewable project developers to obtain financing. However, it appears that the availability of unbundled RECs to meet RPS targets is more a symptom of underlying problems than the cause.[91]

The heavy reliance on short-term markets appears to be a residual effect of Massachusetts' 1998 deregulation. Utilities were required to divest themselves of generation assets and provide only distribution and transmission services.[92] Customers were then able to switch to other providers, but in fact the utilities still provide power for most of the state – in February 2005, they provided electricity accounting for 75 percent of the state's load and 96 percent of its customers.[93]

The energy wholesalers (formerly subsidiaries of the utilities) compete twice a year to provide the utilities with power in twelve-month contracts. For the load that serves large commercial and industrial customers, the contracts are even shorter.[94] According to several experts contacted, the current market structure gives energy companies and utilities little incentive to lock themselves into long-term contracts, since they are bidding to provide energy to utility customers on such a short time horizon. Long-term contracts would be too risky. So they purchase power and RECs in short-term markets.[95]

The Massachusetts Division of Energy Resources (DOER) predicts that the gap between renewable supply and demand will only last a few years. The capacity of New England renewable projects eligible to supply RECs to the Massachusetts RPS was expected to be 221 MW by the end of 2005.[96] While this is insufficient, DOER projections have an additional 40 projects in the pipeline that could add 1,395 MW of RPS-eligible capacity in New England by 2008. According to these projections, supply would catch up with demand in 2006.[97] However, past history indicates that the citing and approval process for many of these projects could be a rocky road.

Massachusetts State Initiatives to Strengthen the Market

State government has taken some initiatives to improve the functioning of the Massachusetts REC market. Funds collected through Alternative Compliance Payments are provided to the Massachusetts Technology Collaborative (MTC), a quasi-public agency that encourages renewable energy development.

One of their initiatives is the Massachusetts Green Power Partnership. This program is purchasing long-term contracts for RECs to help renewable projects obtain financing. The program offers contracts of up to 10 years.

In addition to straightforward purchase of RECs, the program also offers risk hedging through "put" and "put/call" options. In a put option, the developer has an option to sell RECs to MTC at a defined price, providing the developer with a guaranteed price floor. In a call option, MTC gains the option to purchase RECs at another price. For example, the put price might be $20 per REC, and the call price $30. If market prices fell below $20, the developer could exercise the option to sell the RECs to MTC at $20 each. If the market price rose above $30, MTC would exercise its option to purchase them at $30.[98]

The reach of this program is somewhat constrained by credit issues and MTC's lack of bonding authority. Lenders will not finance a renewable project based on an MTC procurement contract unless MTC actually places the funds to satisfy the contract into escrow ahead of time. Nevertheless, in its recently completed first round, MTC helped to fund six renewable projects totaling 100 megawatts. MTC contracts obligated $21 million and will allow MTC to purchase RECs at $25/MWh, considerably less than the current market price.[99]

Another policy adopted by Massachusetts to improve its REC supply is a requirement that state-subsidized projects sell at least 30 percent of the RECs into the Massachusetts market for 10 years.[100]

TEXAS

Texas has seen rapid growth in its wind sector since the initiation of the RPS, and the state now ranks second only to California in wind generation. The state has large areas of windy land suitable for further development, particularly in the Panhandle region. The growth of the Texas wind industry has been helped by both the RPS program and the federal production tax credit for wind energy.[101*] Planning for an expansion of windpower in Texas actually predates the RPS and the deregulated era. In the late 1990s, customer surveys required by the Texas Public Utilities Commission revealed a strong customer demand for more renewable energy.[102]

The Texas electricity market is very self-contained compared to other states. The Texas electricity grid has little interconnection with the grids serving the rest of the country.[103] The Electric Reliability Council of Texas (ERCOT) provides transmission and distribution for about 85 percent of the Texas electricity load.[104] ERCOT administers the Renewable Energy Credits Trading Program and runs the REC tracking system.

Texas passed deregulation legislation in 1999, and began allowing competition in 2001. Utilities were required to separate their generation from their transmission and retail service operations, but were not required to fully divest themselves of generation assets.[105] To foster competition, each utility was required to split into three companies: a Retail Electric Provider, a Lines and Wires Company, otherwise known as a Transmission Distribution Service Provider, and a Wholesale Generator.[106]

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[*] The federal Production Tax Credit has been an important subsidy for the wind industry, although it has become somewhat sporadic in recent years. According to the Union of Concerned Scientists, it was originally enacted as part of the Energy Policy Act of 1992. It was originally scheduled to sunset on June 30, 1999, but was extended until December 31, 2001. It was revived March 2002 and extended for a second time until December 31, 2003. In October 2004 it was extended until December 31, 2005, and then later expanded to include additional renewable energy resources. See Union of Concerned Scientists, "Renewable Energy Tax Credit Saved Once Again, But Boom-Bust Cycle in Wind Industry Continues," http://www.ucsusa.org/clean_energy/renewable_energy/page.cfm?pageID=121.

RPS and REC Market Rules

The Texas RPS came into effect in 2002.[107] The goal is to ensure that an additional 2,000 MW of generating capacity from renewable energy is installed by 2009. Targets for each retailer are based on their share of statewide energy sales.[108]

Since September 1999, the cutoff date for generation to qualify as "new," wind generation capacity has grown in Texas by about 1,234 megawatts, and the state has gained 1,282 MW of renewable capacity.[109] As a result, there has been serious consideration of raising the RPS targets, but such efforts have so far not cleared the legislature.

RECs can be produced by wind, geothermal, hydroelectric, wave, tidal, biomass energy. New sources are those put into place after September 1, 1999.[110] RECs can be banked – they have a usable life of three years (including the year of purchase).[111] RECs may be produced by certified generators not located in Texas if (1) the first metering point for such generation is in Texas and (2) all generation metered at the location of injection into the Texas grid comes from that facility.[112]

A compliance penalty can be paid in lieu of procuring RECs or renewable energy. The compliance penalty is the lesser of $50 per MWh or 200 percent of the average market value of credits.[113]

Texas' Market Experience So Far

The Texas REC market presents some strong contrasts with that of Massachusetts. REC prices are lower; renewable energy supply has been ample to meet the demand, and most of the RECs are purchased bundled with electricity under long-term purchase agreements with a few large electricity suppliers. Overall the market seems to be working well, although there has been some concern that owners of large blocs of RECs might be holding on to them in order to boost prices.[114]

The widespread use of long-term contracts probably has several sources. Wind power has actually been cheap enough to be fairly price-competitive with fossil fuel resources, and utilities have been buying and banking more RECs than they need, as a hedge against gas price rises.[115]

As noted earlier, the move toward building and procuring more windpower originated during the era of regulated utilities. The setting of RPS targets encouraged this trend to continue, but targets were set at a level that the state's energy planners knew could be readily achieved.[116]

Another factor in Texas is that the deregulation did not completely separate the energy retailers subject to the RPS requirements from generators. A utility was required to sell off power facilities only if its power generation supplied more than 20 percent of the market, which in practice required little actual divestiture. Furthermore, the deregulation law encouraged the newly created retailers to procure their electricity in long- and medium-term contracts.[117]

RECs were initially expected to trade for about $5/MWh because of the state's abundant wind resources. However, RECs have traded higher, at $11-15/MWh in 2004. REC demand and prices have probably been boosted by electricity transmission constraints.[118] Although higher than expected, the prices are considerably below the compliance penalty payments. It should also be noted that the effective price for RECs that are procured bundled with electricity in long-term contracts is probably much lower than the above prices, which are spot market prices for unbundled RECs.[119]

There are no data available indicating what proportion of the RECs traded are bundled or unbundled. However, it appears that the REC market is functioning more or less as it should. Unlike Massachusetts, unbundled RECs are not the main tool for RPS compliance, but rather provide flexibility where needed. For the larger retailers, RECs tend to be used around the margins when there is uncertainty about the amount of renewable electricity they will need to purchase and they need to make their RPS accounts balance out.[120]

Like California, Texas has independent retailers that provide electricity directly to commercial and industrial customers. It appears that at least some of the smaller ones rely entirely on RECs because long-term renewable electricity procurement is infeasible for them. One small independent retailer contacted at random for this report had purchased its entire 2004 RPS obligation with a purchase of 2,000 MWh of unbundled RECs from the Lower Colorado River Authority.[121] In addition, some of the larger retailers may be purchasing unbundled RECs short-term when credit problems make it difficult for them to make long-term contracts.[122] It is also worth noting that in at least one instance, a wind project was financed using separate 10-year contracts for RECs and electricity with different buyers for each product.[123]

At the end of 2004, there were 27 generators who had created accounts in the online ERCOT system to sell RECs. They possessed an installed capacity of 1,190 MW. Seventy-two competitive retailers had accounts to purchase RECs. The total REC requirement for all competitive retailers for 2004 was 2.67 million RECs. The total energy generated by renewable energy resources tracked by the REC program for 2004 was 3,685,014 MWh.[124]

In 2003, 87 percent of the state's eligible renewable generation was from wind power, six percent was from hydroelectric, and another six percent from landfill gas. The remainder, solar and biomass, together accounted for one percent.[125]

The state's progress in adding renewable capacity has led to proposals to raise the target of the RPS from the current goal of 2,000 MW of new capacity by 2009. Legislation to do this was unsuccessful in the most recent legislative session.

POLICY OPTIONS

The question for California policy makers is whether or how to modify RPS compliance mechanisms to permit more flexibility for utilities and facilitate compliance by non-utility electricity suppliers.

There is a spectrum of options available. California's RPS could continue to rely exclusively on long-term contracts. It could augment the current contracting policy with more flexible compliance options. It could allow limited use of RECs and perhaps eventually permit the wider use of RECs once the regional tracking system is in place and functioning.

OPTIONS OTHER THAN REC TRADING

As noted earlier, the current RPS procurement rules require that any generator bidding for an RPS procurement contract must incorporate into its bid the transmission costs to deliver the power to the utility. This could have the effect of limiting the pool of viable bidders for a given contract due to transmission congestion. As TURN points out, even if most of the procured electricity were deliverable and only a small proportion of it was constrained, the bid would have to include the entire cost of transmission infrastructure to eliminate that congestion.[126]

A proposal that stops short of REC trading could provide some flexibility in the near-term for IOUs. It is sometimes called "inter-utility swapping." Swapping would allow utilities to avoid the deliverability requirements that currently apply to renewable power purchases counted toward RPS obligations. A related proposal, referred to as "curtailability," would allow the bid to be modified to reflect the difficulty of delivering some portion of the electricity.[127]

For example, suppose SDG&E wanted to purchase power from a renewable generator in a remote location in PG&E's northern California service territory, but transmission constraints made it difficult or impossible for the power to reach SDG&E. In this case, SDG&E could enter a contract to purchase power from the generator, and a separate agreement to swap power with PG&E. The renewable generator would deliver its output to PG&E's service territory. Meanwhile, PG&E would deliver an equivalent amount of power to SDG&E from some other location that avoided transmission constraints.

The end result would be similar to REC trading in that the electricity and the credit for a renewable purchase end up with different buyers. In the example just described, the physical output of the renewable generator ends up with PG&E. The credit for the renewable purchase under the RPS program goes to SDG&E. This is just one example of variations on swapping that could be crafted in different situations. The rule changes to allow swapping could probably be implemented administratively.

This kind of swapping is already occurring in New Jersey, where unbundled REC trading will not be allowed until an electronic tracking system is established.[128] Swapping would not provide California all the flexibility promised by RECs. It would be more complicated to coordinate the electricity swaps rather than just trading the RECs. And it would leave open the question of whether non-utility retailers could feasibly meet the RPS contract term requirements.

RECs are not strictly necessary to deal with the contract term preferences of ESPs, however. One option that stops short of unbundled REC trading would be to allow non-utility retailers more flexibility to use short-term contracts for their renewable energy procurement. It appears that the CPUC already has some discretion to approve shorter contracts.[129]

A very different option that would continue to rely exclusively on long-term contracts has recently been proposed by The Utility Reform Network (TURN). This would create a new central procurement entity that would buy renewable power on behalf of non-utility retailers. The entity would enter into long-term energy procurement contracts and be regulated by the same process currently used for utilities.

SHORT- AND LONG-RANGE OPTIONS FOR IMPLEMENTING REC TRADING

Although REC trading is not the only available solution, it is worthwhile to explore in some detail how it might be implemented. We will divide the implementation process into shorter-range and longer-range considerations.

Shorter-Range Considerations

If California adopted REC trading, it is likely that the WREGIS system would ultimately be used as the tracking system. However, the WREGIS system is unlikely to be fully operational before 2007.

Given that WREGIS is not yet ready, it might be necessary to limit the number of players and the kinds of trading in order to keep the regulation of such trading manageable. Given the concerns about keeping the benefits of the RPS inside California, REC trading could also be limited geographically – for example, only allowing RECs that were initially delivered into the state bundled with electricity.

A similar proposal was made by the Administration and discussed in CPUC proceedings recently.[130] It envisioned a first stage of trading in which only one unbundled trade of each REC would be allowed, and in which the buyer would have to be a participant in the RPS program.

Such proposals for restricted trading might result in a relative lack of market liquidity. On the other hand, they could provide more options and flexibility than are now available. Limited market experimentation would also inform future decisions about the advisability of expanding or contracting trading opportunities. Meanwhile, the CPUC could continue to require that the bulk of utility procurement continue to occur through long-term contracts.

Non-utility electricity suppliers and utilities would want eligibility for Supplemental Energy Payments for REC purchases. However, Supplemental Energy Payments involve a complex set of rules for comparing prices in long-term energy procurement contracts to estimated market prices. There may not be a simple way to modify these rules for RECs, which are not units of energy and are not necessarily bought in long-term contracts. In the interim, it might be preferable to initially use a simple formula for disbursing some Public Goods Charge funds to retailers to help cover REC costs, for example allotting each a share of the available funds based on their electricity market share.

Longer-Range Considerations

Once the WREGIS system is in place (2007 or later), the state would have the infrastructure for a more flexible REC market if that were deemed desirable. For example, WREGIS would be able to readily track a given REC through multiple trades among a broader array of parties, including brokers and others not directly regulated under the RPS. Other rules that could be adjusted over time might include the lifespan of RECs and the ability to bank them. The desirability of allowing or excluding RECs from other states could be revisited if necessary.

If REC trading were to be implemented, the state would need to clarify property rights issues relating to PURPA and distributed generation contracts. Uncertainties about these issues could unnecessarily limit the supply of available RECs and make it difficult for those involved to make plans about participating in the market. However, the resolution of these issues is not an absolute prerequisite to initiating some form of REC trading.

If renewable project financing appeared to be a problem, the state could introduce new programs like those being tried in Massachusetts, in which the state designates an entity to enter into long-term contracts for RECs or REC options in order to help renewable projects get financing.

The system of using Public Goods Charge funds to subsidize renewable procurement might need to be revisited if REC trading became an integral part of the RPS. The Supplemental Energy Payment system is geared toward IOUs and long-term procurement contracts, but this future RPS would have more diverse participants and more diverse methods of renewable procurement. In the long run, the state might want to devise an entirely new means of distributing Public Goods Charge funds in support of the RPS program.

The following table summarizes the short- and long-range issues just described.

Summary of Interim and Long-Run Options

	Problem/Issue	**Interim/Short Run Options (from now through 2007 or 2008)**	**Long-Run Options (post-WREGIS rollout)**
1	SDG&E, PG&E compliance and transmission constraints.	1. Inter-Utility Swapping. 2. Limited REC trading (see #5 below).	Possibly expand scope of REC trading.
2	Non-utility retailer compliance and difficulty w/long-term contracts.	1. Limited REC trading (see #5 below). 2. Flexibility in contract term length. 3. Create procurement entity that makes long-term contracts on behalf of non-utility retailers.	If using REC trading, consider expanding the scope and flexibility.
3	Supplemental Energy Payments for RECs.	1. Allocate reimbursement funds up to non-utility retailer's pro-rata market share. 2. Do nothing – no payments made.	Consider whether to completely overhaul or replace the current Supplemental Energy Payment system.
4	REC property rights for distributed generation and PURPA contracts.	Delegate to regulators, legislate, or do nothing; ideally regulators will resolve in short run but may not happen.	Delegate to regulators or legislate.
5	Verification and tracking of REC transactions.	Regulators implement manual tracking system based on currently available metering and other generator-specific data, plus reviewing contracts to verify procurement.	WREGIS (electronic tracking and accounting system).
6	REC market rules (who can trade, what RECs are eligible, REC banking, unbundling of environmental attributes).	Define limited market that stays within capability of manual tracking system. Err on side of caution.	Adjust market rules over time, balancing goals of RPS, market liquidity, etc.
7	Need for long-term contracts to finance renewable project development.	Continue to require utilities to procure significant portion of RECs via long-term bundled or unbundled contracts.	1. Continue to require some long-term contracts by utilities. 2. Establish state programs to procure RECs in long-term contracts and/or offer options guaranteeing long-term prices. 3. Monitor ability of markets to incorporate REC revenues into contracts and financing.

Final Thoughts

If the state were to implement REC trading, the goal should be to add flexibility to the existing system so that retailers have a variety of tools for compliance. A mix of short- and longer-term transactions could potentially help lower RPS compliance costs while still allowing new renewable projects to be built.

REC trading is not a panacea – it does not guarantee a smoothly-functioning electricity market or RPS program. RECs raise some difficult policy issues, and there may be other means to achieve at least some of the same ends. However, REC trading also does not need to represent an immediate and radical overhaul of existing policies. REC trading could be adopted incrementally, preserving desirable features of the existing RPS system while potentially adding some useful flexibility.

APPENDIX: OVERSIGHT OF PRE-WREGIS REC TRADING

A key question is whether regulators can track and verify some limited form of unbundled REC trading before the automated WREGIS system is in place. To do so requires obtaining data about the output of each generator, and then comparing that to the procurement reported by retailers. In the absence of an automated REC tracking system like WREGIS, regulators must tally each procurement transaction, which can be verified by the regulators or an independent third party by reviewing contract paths.

Some precedents already exist for doing this: in the RPS program, and before that in the now-defunct Customer Credit program and the power procurement disclosure programs. The last two programs even included tradable RECs and similar features.

The CEC Customer Credit program, initiated in 1997, funded ESPs to provide rebates to their customers for purchases of renewable energy.[*] It accepted RECs for compliance for wholesale transactions. It also had flexible electricity delivery requirements similar to what was described earlier as "inter-utility swapping" – the renewable energy did not have to be physically delivered to the end-use customer. Renewable electricity could be delivered anywhere as long as an equal amount of system power was delivered to the customer.[131] The Customer Credit Program was discontinued after the suspension of Direct Access.

The Power Source Disclosure Program,[†] which is still in effect, requires retail suppliers of electricity to disclose to consumers information on the sources of energy being purchased. This includes reporting renewable procurement. tracks and verifies renewable procurement and allows flexible compliance including RECs.[132]

In the Power Source Disclosure Program, procurement is self-reported by utilities verified by an independent auditor. Requiring a full-fledged annual audit was determined to be too costly. So CEC developed procedures by which auditors would perform a standardized, streamlined verification process.[133‡]

The RPS program also verifies procurement. Because no one data source is completely comprehensive for determining the output of all the renewable generating facilities of varying sizes and kinds, the CEC uses a variety of data sources, including metering data from the Independent System Operator (ISO) and data from the federal Energy Information Administration.[134]

There would be limits to what verification systems can do. Double-counting is one potential problem. It might be difficult to detect that a generator was selling the same RECs both to an RPS participant and to another buyer outside the RPS program – for example, a buyer in another state, or a municipal utility that didn't participate in the RPS. When the time came for regulators to tally up all the RECs claimed for RPS compliance

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[*] Established by Senate Bill 90 (Sher), 1997.
[†] Established by Senate Bill 1305 (Sher), 1997.
[‡] These are known as "agreed-upon procedures" or the "Assurance Protocol."

against the RECs produced by generators, they would be unaware of such sales if the generators failed to report them.

This problem could arise even with an electronic verification system like WREGIS. But an electronic system, in which each REC has a unique identifying number in an electronic database, would probably make investigating potential violations simpler. REC buyers could also verify for themselves whether a REC they were being offered was really available for purchase.

Regardless of the type of tracking system, if it relies on self-reported data, then the rules could require some spot-checking of a small proportion of these reports with fuller audits. The rules could also require parties to attest to the accuracy of their statements and include strong penalties for false reports.

GLOSSARY OF ACRONYMS

CCA – Community Choice Aggregator

CEC – California Energy Commission

CPUC – California Public Utilities Commission

ESP – Electric Service Provider

ERCOT – Electric Reliability Council of Texas

FERC – Federal Energy Regulatory Commission

IOU – Investor Owned Utility

ISO – Independent System Operator

MTC – Massachusetts Technology Collaborative

MW – Megawatts

MWh – Megawatt Hours

NEPOOL – New England Power Pool

NREL – National Renewable Energy Laboratory

PG&E – Pacific Gas and Electric Company

PPA – Power Purchase Agreement

PURPA – Public Utility Regulatory Policy Act of 1978.

REC – Renewable Energy Credit

RPS – Renewable Portfolio Standard

SCE – Southern California Edison

SDG&E – San Diego Gas and Electric Company

WECC – Western Electricity Coordinating Council

WREGIS – Western Renewable Energy Generation Information System

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