

UNIVERSITY OF CALIFORNIA
Santa Barbara

**AN ANALYSIS OF TRADABLE CREDITS
AS A POTENTIAL COST MINIMIZATION TOOL FOR
CALIFORNIA RPS IMPLEMENTATION**

A Group Project submitted in partial satisfaction of the requirements for the degree of
Master's in Environmental Science and Management
Donald Bren School of Environmental Science & Management

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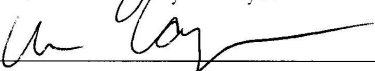
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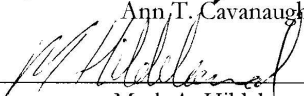
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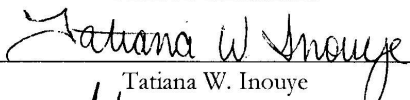
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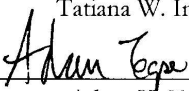
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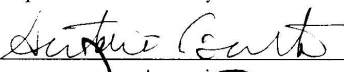
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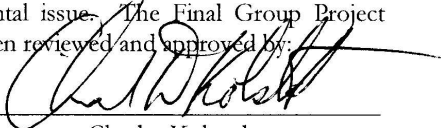
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The Group Project is required of all students in the Master's of Environmental Science and Management (MESM) Program. It is a three-quarter activity in which small groups of students conduct focused, interdisciplinary research on the scientific, management, and policy dimensions of a specific environmental issue. The Final Group Project Report is authored by MESM students and has been reviewed and approved by:



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ABSTRACT

A well-designed Renewable Portfolio Standard (RPS) is an effective policy instrument for increasing renewable energy development within a state's energy portfolio. California's RPS, passed in September 2002, encourages renewable development by setting standards for electricity providers in the state. The mandate requires the state's largest electricity providers, the major large investor owned utilities (IOUs), to increase their procurement of renewable electricity by one percent per year until reaching a final target of 20 percent by 2017. While the policy's framework is already established, it is expected that the California Energy Commission (Energy Commission) and Public Utilities Commission will finalize implementation rules by the end of 2004. One component of the implementation proceedings that will be decided upon collaboratively by the state agencies is the use of tradable credits for compliance. Tradable credits would allow the utilities to procure, trade and retire credits for RPS obligations. Tradable credits are favored by some states as a flexible, market-oriented approach, but are criticized by others for their displacement of the attributes from renewable electricity. This analysis investigates tradable renewable energy credits (TRECs) as a possible compliance mechanism. To evaluate the necessity of TRECs, a model of the California electricity market was constructed to simulate the expected cost of the RPS program to the state. In all but one scenario, the model predicted that existing RPS funds would be insufficient, thus supporting the argument that cost-saving policy options, such as TRECs, ought to be explored. The sufficiency of ratepayer funding is especially critical to California's RPS success because IOU compliance is required only to the extent that funding is available. Based on an analysis of TREC market characteristics, existing price data and other state experiences with TRECs, this study found that TRECs might represent a cost-saving opportunity for the utilities, and thus ratepayer funds. Therefore, this project recommends that the Public Utilities Commission and the Energy Commission allow TRECs as a compliance mechanism towards the RPS mandate given eligibility criteria.

EXECUTIVE SUMMARY

Over the last decade a number of laws have been implemented at both the state and federal level to promote the development of renewable energy. The renewables portfolio standard (RPS) is an example of a policy tool designed to displace conventional energy sources by requiring sellers of electricity to procure a specified capacity or percent of generation from renewable resources. In 2002, California enacted its own RPS program that requires the three major state utilities (Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric) to increase their procurement of renewable energy by 1% per year until reaching the final target of 20% of retail sales by the year 2017.

The success of the California RPS is contingent upon the sufficiency of public funding. Under current RPS compliance rules, utilities are only required to pay the established market price referent (MPR) for renewable energy procurement imposed by the RPS. The California Energy Commission (Energy Commission) pays the additional above-market costs for the renewable electricity in the form of supplemental energy payments (SEPs). Funding for SEP payments comes from the Public Goods Charge (PGC) fund, derived from ratepayers, to which \$70 million per year has currently been allocated. If SEP funding is insufficient to cover the above-market costs of renewable generation during a particular compliance year, the utilities are not obligated to meet their remaining RPS requirements for that year.

The adequacy of SEP funding to meet the RPS procurement requirements of the three utilities will depend upon multiple factors, including the quantity of PGC funds, future natural gas prices, cost of eligible renewable technologies, generators' bids, and flexible compliance mechanisms. The majority of these factors remain beyond the control of the Energy Commission. For example, annual PGC funds allocated for SEPs have been set at approximately \$70 million; natural gas prices are expected to fluctuate; and the costs of eligible renewable technologies have dropped as they continue to advance within a competitive market setting. While some flexibility mechanisms have already been incorporated in the RPS (e.g., procurement banking), other opportunities exist to further reduce compliance costs by increasing the degree to which market forces are harnessed in the policy design. The use of tradable renewable energy credits (TRECs) is one policy option credited with reducing compliance costs through its ability to increase market participation, enhance market liquidity, and improve utility compliance.

Project Approach

The purpose of this project was to analyze whether potential cost savings from TRECs would provide the Energy Commission with an appropriate policy tool for better ensuring that RPS goals are met. In order to assess the value of TRECs within the California RPS program, this analysis consisted of two stages.

Stage I

A model of the California electricity market was developed to calculate the above-market costs of renewable energy production imposed by the RPS. For the years 2005, 2010, and 2015, the model was run for four scenarios that consisted of high or low natural gas prices and with or without the Federal Production Tax Credit (PTC). The objective of these model runs was to identify the scenarios expected to impose the greatest strain on the PGC fund, and to determine if and when the costs would exceed fund availability.

Stage II

Existing TREC markets were characterized to determine the factors that influence these markets. Such factors included price determinants, market size, and credit ownership. The analysis also examined existing price data from three markets as well as reviewed other state experiences with TRECs. The purpose of this assessment was to better gauge how a TREC market could develop in California, to apply lessons learned from other states to the final policy recommendation, and to ultimately determine whether cost savings are available with the adoption of TRECs.

Model Cost Results

The results of the model indicate that the cost to the state for meeting the RPS requirement will most likely exceed allocated PGC funding. In three of the four model scenarios, the expected cost to the state exceeded the total funding available. Funding will be sufficient through 2017 only if the Federal PTC is reinstated and if natural gas prices continue to rise.

Because the model output is based on the cost of producing the renewable electricity needed to satisfy RPS requirements, the results of the model represent the expected minimum cost to the state. The actual bids will likely fall between the respective resource's cost of production and the marginal cost of renewable production. Therefore, the costs to the state are anticipated to exceed the costs predicted by the model, further illustrating the need for cost-minimizing policy options such as TRECs.

TREC Assessment Results

The analysis of existing TREC policy and pricing data found that TRECs, with a well-constructed policy design, present an opportunity to: (1) decrease compliance costs, (2) increase market participation, (3) increase the selection of renewable resource options, and (4) not exacerbate the administrative costs of existing policy options.

1. *Reduce Compliance Costs:* TRECs may reduce direct compliance costs to the ratepayer fund through the removal of temporal and spatial components of renewable electricity production. All TRECs have the same value, irrespective of the load during which they were produced, effectively removing integration costs associated with intermittency. Spatially, TRECs minimize transmission costs by allowing utilities to support remotely produced renewable electricity without

requiring the energy to be wheeled to the utilities' service area. It is important to note that TRECs do not eliminate the cost of managing intermittent sources from the system; instead, the costs are passed off to another entity, potentially to the California Independent Systems Operator, the transmission network administrator. Therefore it is likely that the buyers (e.g., the utilities) of TRECs would avoid these specific costs derived from intermittency.

2. *Increase Market Participation:* A TREC market may facilitate greater market entry by allowing small renewable generators who are not otherwise considered for power purchase agreements to sell their TRECs to credit marketers. These credit marketers would essentially serve as aggregators, allowing a number of small generators to participate in the market.
3. *Increase Selection of Renewable Resource Options:* The use of TRECs would allow utilities to meet their procurement targets through the development of the least expensive renewable technologies, regardless of their type or location within the state.
4. *Impose Similar Administrative Costs:* The Energy Commission is currently developing an electronic tracking system that will be part of a region-wide system and capable of tracking TRECs, thereby not exacerbating current administrative costs.

Recommendation

Based on the model's calculation of potential costs imposed by the RPS, this analysis has determined that SEP funds will be insufficient to meet the final RPS goal of 20% by 2017. Thus, the analysis recommends the use of TRECs for compliance, from which cost savings will be a function of increased market liquidity and compliance flexibility. In order to successfully integrate TRECs into the California RPS, the study suggests the following:

- SEP Eligibility for TRECs – Current RPS eligibility requirements that apply to bundled transactions should be applied to unbundled transactions. A project meeting the deliverability requirements currently stipulated by law should be eligible for SEPs, regardless of bundling.
- Out-of-State Eligibility – Credits originating outside of California should be eligible for RPS compliance, provided (1) the source of the credits are compatible with the resource eligibility rules as prescribed by California's existing RPS; (2) no ratepayer funding may be used for TRECs generated outside of California (unless they meet delivery requirements currently stipulated by the law; (3) the electricity must be delivered to the western grid.
- Banking TRECs – Banking of tradable credits should be allowed in order to displace the strain on the fund that is expected to occur during the middle years of the program and to hedge against market fluctuations.

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List of Abbreviations

APT	Annual Procurement Targets
CaISO	California Independent System Operator
CCA	Community Choice Aggregator
CEC	California Energy Commission
CPUC	California Public Utilities Commission
ESP	Electric Service Providers
FCR	Fixed Charge Rate
GWh	Gigawatt hour
IOU	Investor-Owned Utility
ISO	Independent System Operator
LCBF	Least Cost Best Fit
LDC	Load Duration Curve
MPR	Market Price Referents
MW	Megawatt (unit of power)
MWh	Megawatt hour
NRRA	New Renewable Resources Account
PIER	Public Interest Energy Research
PGC	Public Goods Charge
PPA	Power Purchase Agreement
PTC	Production Tax Credit
RE	Renewable Energy
REC	Renewable Energy Credit
RFO	Request for Offer
RPS	Renewables Portfolio Standard
RRTF	Renewable Resource Trust Fund
SB	Senate Bill
SEP	Supplemental Energy Payments
T&D	Transmission and Distribution
TREC	Tradable Renewable Energy Credit
WECC	Western Electricity Coordinating Council
WREGIS	Western Renewable Energy Generation Information System

1 INTRODUCTION

Passed into law in September 2002, the California Renewables Portfolio Standard (RPS) requires that the three major California electricity utilities increase procurement of renewable energy until 20% of each utility's electricity sales come from renewable resources. The law ensures that renewable resource development will be promoted by the state through at least 2017. As of this time, the California Energy Commission (Energy Commission) and the California Public Utilities Commission (CPUC) are currently determining and finalizing implementation rules, with final decisions expected within the current calendar year. This project's primary goal was to assess the value of tradable renewable energy credits as a tool for minimizing the cost of the program. The concern for minimizing program costs is based on the results of a model that predicts the expected minimum cost of the RPS to the state. Implicit in this analysis is the assumption that decreased compliance costs imposed by the RPS lead to an increased likelihood of achieving the goals of the RPS (20% renewable procurement).

With the successful implementation of the RPS, California can expect to receive both economic and environmental benefits. First, when compared with conventional resources such as fossil fuels, renewable electricity is attributed with having positive social and environmental impacts on the surrounding localities where it is generated [1]. Next, by displacing conventional electricity generation, renewable electricity reduces carbon dioxide emissions, thereby decreasing the risk of global climate change. The Energy Commission expects the RPS to reduce annual CO₂ emissions on average by about 601,000 metric tons between 2004 and 2017 from new renewable facilities [2]. Finally, displaced generation from conventional sources will also improve air quality. In addition to these environmental benefits, new renewable projects also support local economic development through the reduction of import payments on fuels and the creation of employment opportunities due to the labor-intensive nature of renewable projects [1]. Renewable energy may also increase energy security by decreasing the state's reliance on natural gas and other imported fossil fuel sources that have a history of price volatility. While this analysis does not quantify these benefits, they are widely recognized as positive contributions to local, and ultimately global, communities.

Importantly, economic and environmental benefits help justify the adoption of the RPS; however, the state must overcome challenges to ensure successful implementation and eventual realization of its goals. As the law is currently written, the above-market cost, or premium, of eligible renewable energy is borne by ratepayers via the public goods charge (PGC) fund. Since utilities are not obligated to meet their annual procurement targets if funds are insufficient to cover the above-market costs, the availability of funding becomes a critical determinant of program success, insofar as bids are above the market price referent (MPR). The legally binding linkage between ratepayer funds and RPS compliance is a unique feature of California's policy that poses a particular challenge to the state for ensuring both policy implementation and fund sufficiency.

One way to encourage market development of renewable technologies is already determined by law: renewable generators are eligible to receive payments from the state to defray the above-market costs of generating renewable electricity with ratepayer funds. To improve transparency and keep costs competitive, IOUs are required to select renewable contracts through a confidential bidding process with specific selection guidelines, such as a “least-cost” and “best-fit” criteria.

Because the RPS places a cost burden on the state, it is imperative that rules are developed to minimize these costs. While the RPS currently incorporates some market-based mechanisms for minimizing costs, such as the competitive bidding process, the integration of TRECs may present an attractive opportunity for increasing market liquidity, as TRECs are associated with injecting flexibility into the compliance process.

The focus of this project is to assess whether allowing tradable RECs as a cost-minimizing mechanism is both justified and advisable. Consequently, this project hinges upon two main analyses: (1) a model that calculates the minimum expected cost of the RPS program to the state to determine the sufficiency of the existing funds; (2) a qualitative analysis of TREC market characteristics, existing price data, and other state TREC experiences to gauge whether TRECs offer cost-savings for an RPS program. This report concludes with a recommendation to the Energy Commission based on the results and associated implications of these analyses.

2 BACKGROUND

2.1 What is a Renewables Portfolio Standard?

An RPS is a relatively new policy instrument for promoting renewable energy development that requires designated sellers of electricity to procure a target energy capacity or generation from renewable resources. The RPS was first introduced in the United States [3] and is now being reviewed and implemented by other nations. To date, within the United States at least sixteen states have enacted some version of a renewable portfolio standard, and three more are considering adoption.¹ Typically, a utility can meet its RPS obligation by one of three ways: (1) generating electricity from its own eligible resources; (2) purchasing and transmitting energy from another party; or (3) purchasing tradable credits. To be effective, an RPS should have clearly defined targets, eligibility requirements, and implementation procedures [4]. Once laws and guidelines are in place, the governing body's role is generally limited to certifying eligible generators, verifying compliance, imposing noncompliance penalties, evaluating and approving contracts, and if applicable, managing a tradable credit accounting system.

2.2 The California RPS

Signed in September 2002, Senate Bill (SB) 1078 and SB 1038, as amended by SB 67 and SB 183, established the California RPS. SB 1078 requires,

“retail sellers of electricity, such as investor owned utilities (*IOUs*), to increase the renewable content of their energy deliveries by one percent per year...over a baseline level...[and] annual incremental procurement continues until renewable energy comprises 20% of the IOU's energy portfolio, a target that must be achieved by December 31, 2017” [6].

Recent state-level discussion has proposed an “Accelerated RPS” that would require the same energy goal to be achieved by 2010. Energy Commission sources reveal that the Accelerated RPS has received political traction and is likely to be pressed forward in legislative proceedings.

Most progress in implementing the RPS has been made in regard to the three major IOUs: Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E). IOUs meet their RPS requirement by increasing their renewable resource procurement by at least 1% per year above their baseline, which is

¹ States with RPS mandates: Arizona, California, Connecticut, Iowa, Maine, Maryland, Massachusetts, Nevada, New Jersey, New Mexico, Pennsylvania, Texas, and Wisconsin. States with RPS Goals: Hawaii, Illinois, and Minnesota. States considering RPS: New York, Colorado, and Rhode Island..

determined by each utility's 2001 baseline level of procurement [7]. The sum of the 1% increase and the baseline is referred to as the annual procurement target (APT). At the time of this writing, baseline numbers submitted by each utility were under review at the CPUC. Upon approval, the numbers will be made public prior to the first RPS solicitations.

As stated in the law, the purpose of the California RPS is to:

- Increase the diversity, reliability, public health and environmental benefits of the energy mix.
- Increase California's reliance on renewable energy resources to promote stable electricity prices, protect public health, improve environmental quality, stimulate sustainable economic development, create new employment opportunities, and reduce reliance on imported fuels.
- Potentially ameliorate air quality problems throughout the state and improve public health by reducing the burning of fossil fuels and the associated environmental impacts.
- Complement the Renewable Energy Program administered by the State Energy Resources Conservation and Development Commission [6].

The CEC and CPUC have jointly worked to establish rules of implementation for reaching the policy's goals. It is expected the RPS will be effective in 2004, with first solicitations made between June and September of 2004.

The following is a brief description of the essential rules of the California RPS. For a more detailed description of the law's design, refer to Appendix B.

2.2.1 Renewable Eligibility

Under the RPS statute, a renewable energy resource is eligible based on technology and locational requirements. First, an eligible facility must use one of the following technologies: biomass, solar thermal, photovoltaic, wind, geothermal, fuel cells using renewable fuels, small hydroelectric generation of 30 megawatts or less, digester gas, municipal solid waste conversion using a non-combustion thermal process, landfill gas, ocean wave, ocean thermal, tidal current, and any additions or enhancements to a facility using that technology. This would include the repowering of older, less efficient facilities that meet repowering standards as defined by the RPS. Second, in addition to facilities located within California, an out-of-state facility is eligible if its first point of interconnection with the grid is located within California, or if it is connected to the Western Electricity Coordinating Council (WECC) grid and has a contract that guarantees to sell its electricity to a California IOU [8].

2.2.2 Tracking and Verification System

The Energy Commission will use an interim contract-path accounting system to verify RPS compliance through 2004. However, starting in 2005, an electronic-path accounting system is expected to be operating in coordination with the Western Governors' Association (WGA). California will have one piece of the Western Renewable Energy Generation Information System (WREGIS) and will be capable of verifying compliance by retail sellers, ensuring that renewable energy output is counted only once, and verifying retail product claims. The WREGIS will create one certificate per MWh of renewable energy generated. While the WREGIS will allow for the trade of unbundled RECs, California's piece of the operation will place an additional condition on the transaction that requires the REC to be bundled with its electricity.

2.2.3 Funding

The California RPS requires IOUs to pay renewable generators a price representative of the long-term avoided costs of conventional energy as set by the CPUC for the renewable electricity. Unique to California's RPS is that the generator's "above-market costs" are paid by the state through supplemental energy payments (SEPs), distributed by the Energy Commission directly to the renewable generator. The funding for the SEPs comes from the New Renewables Resources Account (the fund), which is supported by the public goods charge (PGC), a ratepayer surcharge.² The PGC produces \$135 million annually, of which SB 1038 allocates 51.5%, or about \$70 million, to the fund (Figure 2-1).

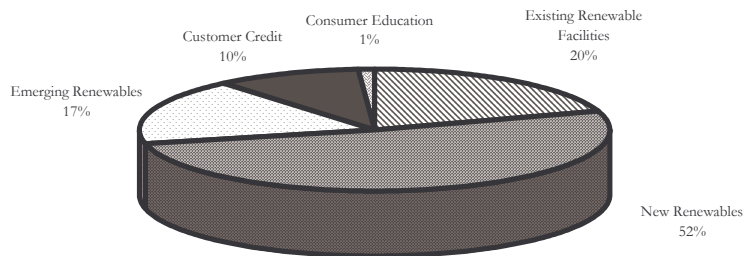


Figure 2-1: SB 1038 Allocation of California Renewables Program PGC Funds, 2002

Source: Energy Commission

² As of November 2003, 15 states have clean energy funds that are generally funded through public goods charges; however, Arizona is the only state in addition to California to allow PGC funds to defray RPS costs.

In order to be eligible for SEPs, a generator must be either new (defined as a resource that began commercial operation on or after January 1, 2002) or repowered (defined as a facility with new capital investments equal to at least 80% of the value of the repowered facility). SEP award eligibility requires that the renewable contracts be a minimum of three years in length. The awards are paid for the lesser of ten years or the duration of the contract with the electrical corporation.

The IOUs are obligated to pursue their APTs to the degree that there is available funding [6]. Demand for available RPS funds will largely be a function of ongoing competitive bidding, a process that is structured to encourage generators to bid at or near their cost of production.

2.2.4 Market Price Referent

As previously mentioned, SEPs will be paid to contract-winning generators based on above-market costs of production. Above-market costs are related to the market price referent (MPR), which in addition to being the maximum unit cost that an IOU is obligated to pay for renewable energy, is representative of the long-term avoided costs of conventional energy and set by the CPUC for the purpose of the RPS. The CPUC has recommended that the benchmark price for base load market prices be set by the production costs of a new combined cycle natural gas turbine plant. Similarly, a combustion turbine natural gas plant will set the benchmark price of peak load electricity. Until an alternative presents itself, the CPUC will use either the base load or peaking referent for the as-available proxy.

2.2.5 Least-cost, Best-fit

The least-cost, best-fit process is the decision process that the IOUs are required to use when selecting a renewable generation bid. Although 'least-cost' may seem to be an unnecessary criterion to use as most business entities seek to minimize costs, recall that the IOU is only required to pay the market price of electricity, as determined by the MPR, for the renewable energy. The 'best-fit' criterion is directly related to the needs of a particular IOU. Best-fit describes the resources that *best* meet the utility's energy, capacity, ancillary service, and local reliability needs. However, as ruled by the CPUC, an IOU will not be excused from complying with its obligations because the resources do not *ideally* match the utility's needs [9].

2.2.6 The Bidding Process

The bidding process begins with each IOU posting its annual renewable energy procurement plan, which outlines the plans for complying with the RPS in the following calendar year. Each IOU then issues request for proposals (RFPs) from renewable generators, to which the generators respond with confidential bids. To discourage generators from making bids based on the level of the market price, the bids are made without knowing the designated MPR for that period. This specific bidding process is

designed to encourage generators to bid relative to their own cost of production, rather than at the market price of renewable electricity. The IOU is then required to select bids based on its least-cost, best-fit criteria.

Whereas the contracts resulting from this bidding process are eligible for funding, bilateral contracts made outside of the competitive bidding process do not qualify for SEPs, although these contracts are allowed to count towards the IOU's APT.

2.2.7 Flexible Compliance Mechanisms

Currently, the RPS includes one central flexible compliance mechanism that provides the utilities with an alternative for meeting APTs should they fall short of the target. The CPUC is expected to allow annual shortfalls in excess of 25% of APT upon demonstration of one of the following four conditions: (1) insufficient responses to request for offers; (2) existing contracts that will provide future deliveries sufficient to satisfy current year deficits; (3) inadequate PGC funds to cover the above-market renewable contract costs; or (4) seller non-performance. This deficit will be allowed for a maximum of three years, by which time the IOU must be in compliance with all previous annual targets.

2.2.8 Penalty Mechanisms

IOUs will incur penalties (1) upon failure to demonstrate a good faith effort to sign contracts with renewable generators in order to fulfill RPS obligations and (2) after all available flexible compliance relief is exhausted. The penalty level as set by the CPUC is currently \$50/MWh, with an overall penalty cap of \$25 million annually per IOU.

2.3 California Energy Resources

Among the 50 states, California is the nation's second largest consumer of electricity; surpassed only by Texas [10]. While California remains a national leader in energy efficiency, its population growth and industrial expansion continue to increase, requiring a proportional growth of supply to be sourced from conventional and renewable resources from in-state and imported locations.

California has one of the largest existing markets for renewable resources in the world. Governmental support of this market, such as with the implementation of the California RPS, will better solidify California's place as a world leader in the development of new renewable resources. The following is a discussion of the existing conventional and renewable resources within California, as well as the potential for new conventional and renewable projects within the state. Please refer to

Appendix C for a complete discussion of:

- IOUs’ current and forecasted demand for electricity;
- conventional and renewable energy resource base;
- electricity imports into the state; and,
- a summary of the main transmission issues facing the state.

2.3.1 Conventional Resources

The majority of the electricity generation within the state comes from conventional sources. Conventional generation consists primarily of natural gas technologies such as single cycle and combined-cycle combustion turbines.

Potential for New Conventional Plants

The potential for new conventional projects within the state is essentially limitless, with the major exception of new hydroelectric projects. New coal and natural gas plants are fuel-driven projects; a key determinant in their construction depends on the current and projected fuel price. However, new coal plants are generally discouraged by the state because of associated high pollution levels. The major hydroelectric potential in the state has been exhausted. New nuclear is legislatively prohibited in California until the state finds a permanent waste repository. Therefore, because of the relatively cheap price of natural gas on the market and relative low pollution levels, new natural gas plants are currently the predominate new technology.

2.3.2 Renewable Resources

Baseline Renewable Procurement for the IOUs under the RPS

Table A shows the baseline and additional renewable energy procurement needed for each IOU to comply with the RPS mandate, assuming moderate projected growth in electricity demand for the state. It is important to note that these baseline figures are based on 2001 data [2] but are not necessarily the baseline numbers that will be set by the CPUC. For the entire state in 2001, the baseline of renewable generation stood at approximately 11% of the total, although this baseline differed for each IOU. In 2001, it

Table A: Renewable Energy Baseline and Future Needs for CA IOUs			
	PG&E	SDG&E	SCE
Baseline (GWh)	7,532	112	11,160
Percent of Total Sales	9.95%	0.74%	15.02%
Needed by 2005 (GWh)	9,611	1,062	12,664
Needed by 2010 (GWh)	14,497	1,853	15,247
Needed by 2015 (GWh)	17,287	3,175	16,434

Source: Renewable Resources Development Report, Energy Commission

was estimated that PG&E sold 7,532 GWh of eligible renewable resources, or approximately 10% of its total energy portfolio [2]. Given this baseline, it is estimated that PG&E will meet its RPS requirement by the year 2013. In 2001, SCE sold 11,160 GWh of eligible renewable resources, or approximately 14% of its total

energy portfolio [2]. Given this baseline, the Energy Commission estimates that SCE will

meet its RPS requirement by 2007. In 2001, SDG&E procured less than 1% of its total energy portfolio from eligible renewable resources. Given this baseline, the Energy Commission estimates that SDG&E will meet its RPS requirement in 2017 [2].

Potential for New Renewable Projects

As already stated, approximately 11% of IOU electricity generation came from renewable resources in 2001, the majority of which originated from geothermal plants (Table B) near the Salton Sea and north of San Francisco at the Geysers. The potential for new renewable projects within the state is physically limited. By its nature, renewable generation is mostly location-dependent and the attractiveness of a project is a function of both the quality of the energy source and its location relative to the grid. For instance, many good sources of wind energy are at such distances from the grid that it is cost-prohibitive to construct a wind farm. With the exception of landfill gas, municipal solid waste, and biomass technologies, renewable generation technologies are constructed on the same site as their fuel source.

Table B: Historical Renewable Electricity Generation: IOUs, 1999 – 2002

Technology	1999 (GWh)	2000 (GWh)	2001 (GWh)	2002 (GWh)
Geothermal	1,543	1,252	997	1,150
Organic Waste	73	34	0	152
Wind	7	7	7	4
Solar	3	3	3	2

Source: Renewable Resources Development Report, Energy Commission

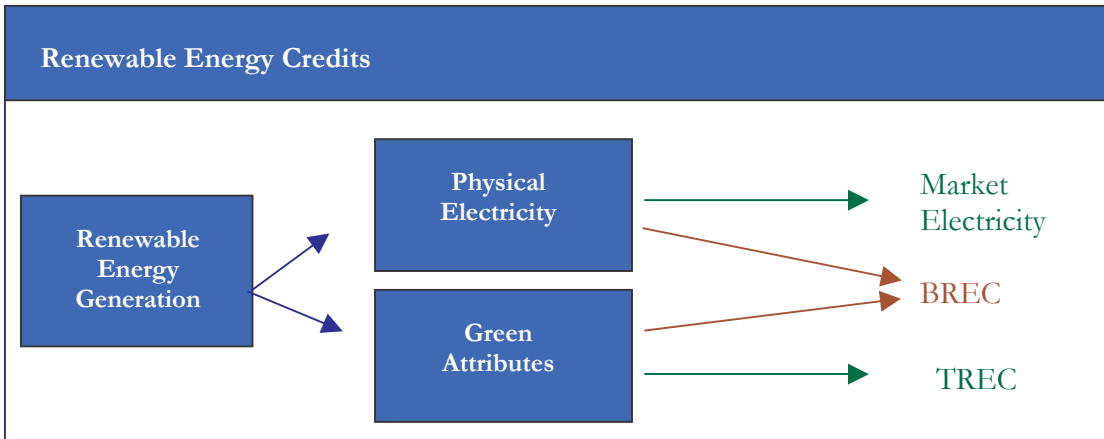
Due to California’s size and resource diversity, the potential for new renewable energy development is unevenly distributed throughout the state. The result is that some IOU service areas are better endowed with renewable potential than others.

2.4 Renewable Energy Credits

A renewable energy credit (REC) represents a unit of electricity, commonly one megawatt-hour, and symbolizes the green attributes of the renewable energy. Generally, a REC is defined as the non-price attribute of renewable generation output, as determined by the unit’s fuel type, emissions, vintage, and RPS eligibility. The California PUC has adopted the definition that “a REC incorporates all environmental attributes associated with the generation of electricity, and that the REC is transferred to the utility and retired” [9].

Renewable generators simultaneously generate physical electricity as well as produce a corresponding number of RECs for each unit of power, which can be “bundled” or “unbundled” from one another. In a bundled transaction, the REC is sold together with its underlying renewable electricity; together the commodities (energy and REC) are sold in one bundled transaction, referred by this paper as a “BREC.” Unbundled transactions allow RECs to be physically separated from their electricity and then traded among utilities or within a financial market. By splitting the renewable electricity, the generator

has two financial commodities: (1) the electricity that can be sold as “brown” power³ and (2) the tradable REC (hereafter referred to as TREC). Whereas BRECs transactions require the electricity to be wheeled into the buyer’s service area via transmission, TRECs are sold irrespective of where the associated power travels. An RPS may either require that RECs remain bundled or it may require the trade of RECs for compliance. At the time of this writing, ten states allow or are considering the use of TRECs for RPS compliance.⁴



TRECs are an example of flexible compliance mechanisms such as tradable allowances, quotas, and emissions trading that have gained in popularity as a means to achieve environmental policy goals. These are widely recognized as efficient, market-oriented approaches to reduce unwanted pollution by harnessing the powers of supply and demand. Credits serve to: (1) monetize environmental benefits, and (2) allow the highest bidder to purchase these credits. Tradable credit markets allow the entities with the lowest costs to sell excessive compliance credits to those with higher costs until market equilibrium is reached. End goals are achieved through trading, thereby accomplishing policy mandates and benefits on a larger scale. Further discussion of the economics of TRECs, in addition to lessons learned from one of the oldest emissions trading programs, is found in Appendix D.

2.4.1 TRECs within an Electricity Market

TRECs are credited with reducing RPS compliance costs through the removal of temporal and spatial components from the transaction, which serves to increase the liquidity⁵ of the electricity market, stimulate market competition, and ultimately lower

³ “Brown” power refers to electricity that is sourced from all fuels, resulting in an undistinguishable mix of sources.

⁴ Nevada, Wisconsin, Texas, Connecticut, Massachusetts, Arizona, New Mexico allow TRECs for RPS compliance. Minnesota, New Jersey, Maine are currently considering adoption.

⁵ Liquidity is a measure of the size of the market and the ease of flow of transactions between market players – the more buyers and sellers that can participate, the more liquid the market.

costs. According to Grace and Wiser, the increased flexibility gained through the creation of a TREC market has the potential to hedge against price volatility [13].

Removing Temporal & Integration Considerations

TRECs provide flexibility to RPS obligated entities because tradable credits essentially eliminate best-fit considerations from IOU decision methodology since unbundled transactions separate the time of generation from the credit. In contrast, BRECs require IOUs to incorporate time of delivery and complex energy trade issues into their load decisions, both of which can represent increased costs [11]. TRECs do not, however, eliminate the integration costs borne by the system as a whole; rather, the TREC price may not reflect the integration costs.

The use of TRECs eliminates the integration costs associated with selecting a particular technology based on the time of generation. As applied to the RPS, integration costs are the “indirect costs associated with ongoing utility expenses from integrating and operating eligible renewable energy resources” [7]. These indirect costs are generally attributable to the inherent low capacity credit⁶ of some renewable energy sources. A BREC system requires that an IOU consider integration costs, such as forecasting the expected time-of-delivery of intermittent sources [11]. On the other hand, TRECs effectively eliminate the IOU’s cost of integrating intermittent sources into its retail load supply [13], as the associated electricity is transmitted directly to the grid in a second transaction separate from the TREC purchase.

Bundling requirements for intermittent resources have been associated with price instability and unreliability, especially during peak loads [25]. The degree of volatility depends upon the IOU’s supply of firm peaker plants that can respond quickly to a change in renewable electricity deployment. However, a TREC system may result in more intermittent, yet less expensive technologies being developed.

Removing Spatial Considerations

TRECs could minimize direct transmission costs by allowing an IOU to support remotely produced renewable electricity while not requiring the renewable electricity to be wheeled from the region of generation to the IOU’s service area. With TRECs, utilities are not obligated to consider the transmission costs based on congestion between their service area and the location of the generator when selecting renewable contracts. As a consequence, TRECs may reduce direct RPS costs by allowing utilities to select contracts based primarily on the cost of generation versus the cost of transmission service. In this sense, TRECs would allow the electricity to be wheeled in the most appropriate direction (e.g., based on transmission service costs and local demand for the electricity) rather than being wheeled to the IOU with whom it has an RPS-driven contract [2]. As a result, the least-cost resources would be developed, the renewable electricity would likely serve local demands, and the IOU would fulfill its obligation to the RPS with credits.

⁶ Capacity credit is defined as capacity a generator adds to the system, as measured by the capacity of a gas reference unit that will result in the same level of system reliability.

Based on the fact that BRECs have a direct-delivery requirement, they are expected to increase the cost of transmission service. This is because BRECs require that electricity be wheeled along specific pathways based on contractual requirements, bottleneck or not. Forcing electricity flow across constrained transmission areas will create additional service costs. These costs would be in addition to the expected costs as measured by the model. Since every generating facility, including conventional sources, has transmission service costs, it would only be the additional cost burden imposed by BRECs that would add to the above-market costs of renewable projects. Measuring the extent of these additional transmission service costs is not within the scope of this project.

2.4.2 Potential Advantages & Disadvantages of TRECs

No policy option is without trade-offs. The degree to which these impacts affect market participants and ratepayers may influence the desirability of implementing TRECs into an RPS program. Following is a discussion of the main positions in favor of and in opposition to TRECs.

Potential Advantages

According to *Gains from an Integrated Market for Tradable Renewable Energy Credits*, a report by Mozumder and Marathe, a TREC market “will result in competition, efficiency, innovation and will deliver renewable energy at a significantly lower price” [11]. The following discussion highlights arguments favoring the inclusion of compliance TRECs, specifically how credits facilitate market participation, increase the supply and diversity of renewable resources, increase RPS compliance flexibility, and improve real time compatibility; together, these factors may lower overall compliance costs.

Additional Market Participants

By removing the requirement that electricity be bundled with credits and wheeled into the buyer’s service territory, TREC markets have the potential to engage more renewable energy suppliers and consumers in the market by allowing the market to guide investment in cost-effective technologies and in the most valuable geographic locations. To name a few, the pool of players could expand to include more generators of varied project sizes; credit traders; and non-obligated entities. Theoretically, the net effect of bringing more participants into the market increases competition and ultimately lowers prices. In turn, this could have the net effect of lowering bid prices.

First, a TREC market may facilitate greater market entry by creating more opportunities for smaller renewable projects to sell eligible credits for energy production that might otherwise be considered too insignificant for a PPA or RFP, providing generators with an economically viable opportunity for selling into the RPS market. For instance, a solar generator producing 1 MWh may have a greater likelihood selling its eligible output as a credit, sold individually or aggregated with more credits, than selling the bundled resource to a utility that prefers to purchase energy in greater amounts (e.g., energy from a 40 MW project).

The emergence of a TREC market could also spur the creation of brokerages that trade compliance TRECs seeking to capture the benefits of the new market. For example, Evolution Markets, Bonneville Environmental Foundation, and Cantor Environmental Brokerage are just three national brokerages that have added tradable RECs to their service portfolio since the emergence of RPS policies. Simply put, brokerages provide another avenue for more participants to access the market.

Creating a tradable REC market enables another group of potential buyers to engage in the market: non-obligated entities. With TRECs, an interested company or individual has the option of supporting renewable energy with the purchase of credits without being required to receive the associated energy. The recent corporate greening trend has been documented and is evident by a growing number of companies purchasing tradable RECs to reduce their environmental impact of their electricity consumption. For instance, the World Resources Institute reported that in September 2003 nine companies in aggregate purchased tradable RECs equivalent to over 250,000 MWh per year. It is unclear if these new consumers would choose compliance or voluntary tradable RECs, but some spillover between the markets could occur, as well as a general increase in the support of renewable energy.

Increased Selection of Renewable Resource Options

By removing the wheeling requirement, allowing the market to direct development of the most cost-effective technologies and locations, TRECs may provide consumers with a greater supply and variety of renewable resources than would be possible with BRECs [14]. The increased diversity could be important for consumers choosing or needing to base renewable energy purchases on technology preferences or requirements, regardless of the resource location. This is particularly important in states with technology-specific requirements.

This could theoretically have a negative impact on renewable resource diversification if one particular technology is significantly less expensive than all others. For example, it is possible that wind energy will dominate the TRECs that are bought to fill the RPS requirement, since this technology has great potential in California and is arguably the most cost competitive technology, although the least available. Since TRECs could shift the IOU's decision emphasis away from best-fit and toward least-cost, the more expensive technologies could suffer in the short-term.

Additional Compliance Flexibility

TRECs offer obligated entities compliance flexibility. First, TRECs provide an alternative compliance option to utilities that do not own or operate their own renewable capacity. Second, utilities can apply TRECs to their RPS requirements if other renewable resources are suddenly insufficient due to malfunctioning equipment or supply. Third, utilities using TRECs are effectively buying critical planning time for identifying the best available resource supply or developing their own renewable generation [12]. Fourth, TRECs allow the environmental attributes to be traded

irrespective of time-of-day considerations associated with the electricity [11]. As a result of these listed benefits, TRECs increase the flexibility for satisfying RPS requirements.

Compatibility with Real-Time Markets

TREC transactions may decrease the complexity of the renewable energy market. For example, a BREC system would force electricity to be treated as two commodities: renewable and non-renewable generation [11]. In a “real-time” market, it would be much more difficult to determine whether a particular energy source was renewable [11]. Because TRECs separate the environmental attributes from the generation, the generation would continue to be treated as a single commodity. Consequently, TREC transactions may facilitate the valuation of electricity units in the real-time market.

Lower Compliance Costs

The associated benefits of implementing compliance TRECs (additional market participants, increased renewable resource options, additional compliance flexibility and compatibility with real-time markets) will likely contribute to lowered compliance costs for RPS-obligated entities. In his report, *The Market for Tradable Renewable Energy Credits*, author David Berry agrees that TRECs may serve to lower the costs of meeting an RPS through gains from trade, which stem from the inherent cost differences of various sources of renewable energy [12]. Robert Grace and Ryan Wisser also state that flexibility in renewable resource development may allow for renewable resources to be used more efficiently. They explain, “Building renewable resources where their all-in costs are lowest relative to the market value of their production and/or where they cause the least relative environmental impact may be the most effective means of maximizing renewable generation” [13]. Consequently, TRECs would be expected to reduce compliance costs as well as to better achieve an efficient use of renewable resources.

Administrative Costs

In a report to the Massachusetts Division of Energy Resources, Robert Grace wrote, “the disadvantages of (a) pure bundled tracking (system) vastly outweigh the benefits, and we reject it from further consideration.” Since the Energy Commission is currently in the development stages of an electronic system that will be part of a great region-wide system and capable of tracking RECs (as of now, the RECs must be bundled), it appears that the associated costs of tracking TRECs would not be burdensome, as the system and processes will already be in place. Interesting, an administrator of ERCOT said that it takes only two employees to oversee the entire Texas RPS tracking system [39]. He explained that they are able to do this because only in-state TRECs are allowed.

Potential Disadvantages

Four primary potential disadvantages have been identified when introducing TRECs into an RPS program. They are (1) displacement of environmental benefits from local ratepayers to remote locations, (2) false valuation of attributes, (3) compromised “best-fit” decisions by IOUs, and (4) uncertainties in a nascent market. Each is discussed in further detail below.

Local Ratepayer Benefits

SB 1078 asserts that displacing local development of fossil fuels results in positive benefits for surrounding communities. It is often argued that local ratepayers are more likely to experience the benefits provided by an RPS when only bundled transactions are allowed [2]. By developing local renewable resources, local communities will enjoy the benefits of displaced fossil fuel plant development as well as the creation of new jobs in the renewable energy sector. These local benefits are threatened if the green attributes are separated from the physical electricity since this makes it possible for IOUs to procure cheap and remotely produced TRECs. In other words, if renewable energy is generated in Region X and the attributes are sold to Region Y, Region Y ratepayers are paying the premium for renewable energy without receiving the accompanying environmental and economic benefits [12].

False Valuation of Renewable Attributes

A TREC system that uses credits to equally represent all renewable energy resources may not reflect the true value of associated attributes, which are separate and distinct. One solution is to disaggregate environmental attributes into separate certificates to better reflect the complete value of individual renewable resources, since not every technology provides the same environmental value. For example, even though closed-loop biomass generation is considered renewable, it cannot claim to have “zero-emissions” like wind or geothermal energy. In other words there would be a separate certificate for carbon, NO_x, SO_x, mercury, particulates and any other attributes that are found to have separate and distinct value.

Compromised Best-Fit Decisions

The allowance of TRECs will permit utilities to make their obligation procurement decisions based largely on price, while precluding considerations given to best-fit such as time-of-day. For example, if wind emerges as the least expensive renewable resource it could dominate the renewable energy market in California while not contributing as much to system reliability as other more expensive resources might have. By excluding best-fit considerations from the transaction, TRECs may impose a cost to the electricity system as a whole by favoring energy sources that are not necessarily the best-fit for the system. Another implication of a selection process more heavily focused on least-price is the potential sacrifice of resource diversification in the case that one renewable technology emerges as the least expensive.

Uncertainty

New and emerging markets can behave in unforeseeable ways. Mark Chupka states in his report, *Designing Effective Renewable Markets*, that introducing TRECs into an aggressive RPS program like California’s might have negative short-term effects on market stability. He suggests that prudent strategies for hedging against TREC spot market price volatility are essential to limiting financial risks to the state [16].

2.4.3 TREC Status in California

Decisions regarding the adoption of TRECs in the RPS rules are deferred until Phase 3 of the implementation proceedings. As a result, there are few published comments from either the Energy Commission or the CPUC on this subject. However, it is noteworthy at this stage that the tracking and verification system currently under development, Western Renewable Energy Generation Information System (WREGIS), will be capable of allowing TREC transactions. In fact, unbundled transactions should be simpler because they would remove the additional condition requiring the credit be bundled with electricity. Even while the technological capability will soon exist, TRECs do not receive universal support. This section summarizes the status of TRECs in California, as well as the predominant political climate surrounding the issue.

Tracking and Verification System

An effective tracking system, when fully operational, will be able to meet the growing monitoring needs of retail sales and transfer of RECs in California. Additionally, a tracking system will minimize the opportunity for double counting of a bundled or tradable REC. It has been stated during a Renewables Hearing Committee that regardless of the final outcome of the decision on TRECs, a fully functioning electronic tracking system would effectively monitor RPS compliance in either case [17]. Robert Grace, Sustainable Energy Advantage, LLC supports the choice of the electronic system when examining alternative tracking systems for Massachusetts: “We note that the disadvantages of the pure bundled tracking approach vastly outweigh the benefits, and we reject it from further consideration”[18].

The Western Regional Governor’s Association is seeking to establish a WECC-wide tracking and verification system to “provide data necessary to substantiate the number of megawatt hours generated from renewable energy sources and support verification, tracking and trading of RECs;” and to “establish a single institution in the West that will issue, track and oversee REC trading” [19]. A main goal of the WREGIS is to create an easy-to-use tracking and verification system that better enables states within the WECC to fulfill their renewable energy goals [17]. The implementation of this tracking system is not expected to affect the decision of whether or not to allow TRECs in California.

Currently under development, California’s portion of the WREGIS system is expected to be online by January 2005 [20], and will replace the existing contract path system. While the WREGIS is designed to accommodate the potential regional trade of TRECs, California’s system will contain an extra provision that requires the electricity be bundled with the REC, which would change were TRECs permitted.

Stakeholder Input

Stakeholder input has been encouraged throughout the RPS implementation process. To better understand the political climate, a group of stakeholders were contacted and asked whether they support the use of TRECs as a compliance mechanism for the California RPS. Personal communication was supplemented with published opinions.

The IOUs and other stakeholders were found to have conflicting opinions on the appropriateness of allowing TRECs and are divided into three groups below: proponents, opponents, and no stance.

Proponents

SDG&E supports the allowance of TRECs based on the fact that TRECs “give the opportunity to better balance energy portfolios” [21]. A report by JBS Energy, *Renewable Portfolio Standard Implementation Issues*, issued on behalf of SDG&E and The Utility Reform Network (TURN), justifies the implementation of TRECs based on the fact that they would allow utilities to comply with the mandate at a lower cost. SDG&E has the smallest service area and the fewest cost competitive renewable resources of the three IOUs. Therefore, it is likely that SDG&E will have to import a great deal of its renewable energy from outside regions. Based on this, SDG&E claims that TRECs will help to “offset the transmission constraints” that will be exacerbated by the RPS mandate.

Nancy Rader, executive director of the California Wind Energy Association (CalWEA), published her position on TRECs in *The Renewable Portfolio Standard: A Practical Guide* (co-authored by Scott Hempling). In this report, Rader and Hempling support TRECs, maintaining that a TREC market will minimize costs (to the fund) by promoting competition through the creation of two liquid markets, one for the electricity and one for the renewable attributes. Rader and Hempling assert that the risk to IOUs for non-compliance is reduced since procuring TRECs is less complicated than procuring BRECs. Rader also claims that the goal of diversity is achieved by allowing small power producers to participate in the market more easily due to reduced transaction costs as compared to large purchase power agreements (PPAs).

Mark McLeod [22], Environmental Defense, has testified in California courts in favor of TRECs. McLeod discussed his position on TRECs in a conversation with the group in February 2004. His support is largely based on the success of the Texas RPS. In response to the theory that TRECs might jeopardize the ‘best-fit’ decision process, he asserts that both the least-cost and the best-fit considerations of a renewable resource is embedded in the competitive process of project development from its inception. Market discipline will assure that the best and cheapest resources are developed, whether the contracts are bundled or unbundled. In Texas, for example, the RPS law initially had a requirement regarding competitive pricing. This stipulation was eventually thrown out by the courts based on the belief that the competitive market would provide more discipline with regards to costs than with a bureaucratic rule. McLeod points out that although Texas allows TRECs in its RPS, the majority of the PPAs are still bundled contracts.

Bill Short, Ridgewood Power, supports the idea of allowing TRECs in the California RPS as long as the standard of delivery allows the TREC to “reflect what took place”.⁷ Mr. Short’s concern is that a tracking system that does not meet a certain standard could be exploited and allow for double counting. He agrees with McLeod that, whether bundled or unbundled, the best resources will be developed based on market disciplines.

Marcus Krembs, GT Energy, stated, “if a competent tracking system is in place there should be no administrative complications (other than lots of paper work) . . . and as long as there is a sufficient system to guard against double counting, it should work well.”⁸ According to Krembs, economic theory suggests that it is advantageous to incorporate TRECs in an RPS market scenario to add flexibility and to better ensure market efficiencies are attained.

Brandon Owens, Platts Research and Consulting, agreed that TRECs “make the most economic sense”, although the firm has no official stance on the matter.⁹

Opponents

Tim Schmelzer, SCE, explained that his utility’s opposition to TRECs is based on the fact that, by definition, TRECs represent an above-market cost.¹⁰ Schmelzer pointed out that the RPS allows, even encourages, renewable contracts that are below the market price of electricity. Allowing TRECs, he contends, would create an above-market cost even for contracts that otherwise would have bid below the market price of electricity.

Steve Munson, Vulcan Power Company, expressed a strong opposition to allowing TRECs in the California RPS.¹¹ Munson insists that TRECs will bifurcate the renewable energy market, which will be a setback for the retail investors in renewable energy. Those renewable investors, he contends, have taken financial risk in developing the renewable market to the point where it is finally cost competitive. Munson maintains that the introduction of TRECs at this point will ruin investments that were made with the hopes of receiving the full value of the renewable energy. Munson is a proponent of disaggregating environmental attributes, which is the creation of separate certificates for each attribute (such as gas emission values). Such disaggregation should better reflect the true value of each renewable resource, since not every technology provides the same environmental value.

⁷ Based on telephone conversation with Bill Short, Vice President of Ridgewood Renewable Power and Consulting, Feb. 18, 2004

⁸ Based on telephone conversation with Marcus Krebs, GT Energy, New Orleans.

⁹ Based on telephone conversation with Brandon Owens of Platts Research and Consulting, Feb. 18, 2004

¹⁰ Based on telephone conversation with Tim Schmelzer, Manager of state legislative policy, SCE, Feb. 18, 2004.

¹¹ Based on telephone conversation with Steve Munson, CEO of Vulcan Power, Feb. 18, 2004

No Stance

As of February 2004, PG&E had not taken a stance on the issue of TRECs.¹² Other stakeholders that have not taken an official stance include Independent Energy Producers,¹³ Green Power Institute,¹⁴ and Platts Research and Consulting.¹⁵

¹² Based on telephone conversation with Donna Barry of PG&E, Feb. 17, 2004

¹³ Based on telephone conversation with Steven Kelly of IEP, Feb. 18, 2004

¹⁴ Based on telephone conversation with Gregg Morris of the Green Power Institute, Feb. 18, 2004

¹⁵ Based on telephone conversation with Brandon Owens of Platts Research and Consulting, Feb. 18, 2004

3 APPROACH

3.1 Overview of Approach

This project pursued two main research goals in developing a final recommendation for whether TRECs should be incorporated into the rules for RPS compliance. In brief, this project sought to determine the minimum expected cost of the program and assess the viability of TRECs as a policy option using cost savings as the primary justification. As explained earlier, the size of available funds allocated to defray above-market costs imposed by the RPS are limited; therefore, this project's main objective was to determine whether TRECs are an appropriate policy tool for minimizing costs.

In the first stage of this study, a model was developed of the California electricity market. The model coarsely simulated the operation of the state power system by finding the minimum cost supply option, given demand. This allowed us to create a renewable and conventional supply curve and a renewable energy demand curve (based on the RPS requirements) to calculate the above-market costs of renewable energy production imposed by the RPS. The model data consists of electricity generation costs by technology, current in-state generation capacity (including historical import data), future generation potential, and projected combined retail sales for the three IOUs. Data was collected for projected needed capacity in 2005, 2010, and 2015 based on both market growth rates and RPS target goals. Using the levelized costs of the renewable generation, the model procured the necessary electricity for base, intermediate and peak loads based on least-cost decisions. For each of the three specified years the model had four scenarios, which consisted of high or low natural gas prices and with or without the federal Production Tax Credit. The objective of this step was to identify the scenarios that are expected to impose the greatest strain on the fund and to determine if and when the costs will exceed fund availability.

The second aspect of this project involved assessing existing tradable REC markets to characterize a "typical" TREC market, including pricing determinants, impacts of market size, and TREC ownership in the case of publicly funded projects. In addition, existing price data from Texas, Massachusetts and New Jersey were analyzed to extrapolate apparent trends in the markets. This was followed by a review of other state experiences with TRECs to glean lessons learned. The purpose of this assessment was to better gauge how a TREC market could develop in California, apply lessons learned from other states to the final policy recommendation, and ultimately to determine whether cost savings are available with the adoption of TRECs. Information was gathered from a state policy and literature review, Evolution Markets LLC, as well as personal communication with stakeholders.

A discussion of each step follows.

3.2 Calculation of Generation Costs under Current RPS

A model of the California electricity market was developed to determine the sufficiency of the fund to satisfy the direct costs of the RPS based on renewable energy production. The model simulates an electricity market in which the total cost to the state is calculated by choosing the least-cost technologies that will satisfy the RPS in a given year. Ultimately, the model outputs the total cost to the state, which is compared to the size of the fund. A summary, complete model description, and model results follow below. A detailed description of the methodology, assumptions, and limitations of the model can be found in Appendix E.

3.2.1 Model Summary

The model was designed to simulate the California electricity market and to minimize the total cost of producing the electricity demanded in a given year. It was designed to take into account the capital, operation and maintenance (O&M), and capital transmission costs of producing each specific generation technology. The model limits the available generation for each technology to what is currently generated and to what is predicted for future in-state generation potential. The model only considers cost and is not capable of determining best-fit.

The cost analysis was conducted for three years – 2005, 2010, and 2015 – each utilizing the following variables:

- *Normal RPS or Accelerated RPS*: The model was run under a normal RPS scenario (20% renewable energy by 2017) and an accelerated RPS scenario (20% renewable energy by 2010).
- *The Federal Production Tax Credit (PTC)*: The model either included the federal production tax credit or excluded it.¹⁶
- *Natural Gas Price Variance*: The model utilized either high or low projected natural gas prices (see Appendix G for exact prices).

Scenarios were run for each of the aforementioned years utilizing the variables until all combinations were exhausted (for example, one run for 2005 was under a normal RPS, with the PTC and high natural gas prices). In total, 20 runs were performed.

The model's results include the percentage of renewable energy procured, the capacity of each technology required, the expected electrical production of each technology, the total expected cost to the fund, and the shadow price of the RPS mandate. The shadow

¹⁶ The PTC is a federal tax credit enacted in 1992 that supports electricity generated by wind, closed-loop biomass, and poultry waste at the rate of 1.5¢ per kWh. The PTC expired on December 31, 2003 and at the time of the analysis it was unclear whether it would be renewed.

price describes the above-market cost to the state if one additional megawatt-hour is required by the RPS. The shadow price is produced by the model and can also be described as the marginal above-market cost of renewable energy. As will be described later, this shadow price is equal to the hypothetical price of TRECs in a competitive California market.

3.2.2 Detailed Model Description

The model was designed to simulate the California electricity market. With Microsoft’s Excel® as a platform, the model uses Premium Solver® to find the least-cost sources of electricity generation to satisfy future demand. Given a series of constraints built into the model, the principal function was to minimize the total cost of producing the electricity demanded in a given year, as expressed by the following equation:

$$\min \sum_i [c_i R_i + O_i \sum_j e_{ij} + T_i R_i] \quad (\text{Equation 1})$$

Where:

- i = technology type
- j = load type (base, intermediate, daily peak or seasonal peak)
- e_{ij} = electricity produced given technology i and load type j (MWh)
- c_i = capital costs for technology i (\$/MW)
- R_i = capacity required for technology i (MW)
- O_i = operating and maintenance costs for technology i (\$/MWh)
- T_i = transmission cost (per MW of capacity) for technology i

Table C lists the costs of new renewable technologies used in the model. The costs account for capital, operation and maintenance and transmission interconnection costs. Most cost data were taken from the Energy Commission’s Renewables Resources Development Report (RRDR) and do not account for the drop in costs of producing renewable electricity that is inevitably expected to occur during the lifetime of the RPS.

Table C: New Renewable Technologies	Costs	Costs
	(\$/MWh)	with PTC (\$/MWh)
Solar	N/A	N/A
Wind: Class 6	\$69.06	\$51.06
Wind: Class 5	\$85.63	\$67.63
Run of the River Hydro	\$62.68	\$62.68
Biomass	\$54.31	\$54.31
MSW	\$43.78	\$43.78
Dry Steam	N/A	N/A

Constraints

The model was subject to the following constraints:

1. *Demand Requirement* – Requires the model to generate a minimum quantity of electricity in a given year, based on projected IOU electricity demand.

2. *Physical Capacity Constraint* – Places a limit on the capacity available for new and existing technologies.
3. *Physical Constraint Considering Load Multiplier* – Calculates the capacity that would be necessary to generate a given demand of electricity during a specific load time.
4. *RPS Requirement* – Represents the minimum quantity of renewable electricity required in a given year to meet that year’s RPS targets. It was based on a weighted 1% ramp-up from each IOU’s respective baseline beginning in 2002 under the “normal” RPS scenario (as opposed to the accelerated RPS).
5. *Hydroelectric constraint* – Limits the total amount of available hydroelectric power by historical generation rather than capacity.

Each constraint is further discussed below.

Constraint 1 - Demand Requirement

The demand requirement of the model was satisfied with Energy Commission forecasts of IOU electricity demand for the years 2005, 2010, and 2015. This demand was separated into four separate loads: base, intermediate, daily peak, and seasonal peak. A load duration curve (LDC) was created from California electricity demand data from August 1, 2002 to July 31, 2003. By integrating the area under the LDC for an average year, a specific percentage of total demand was assigned to each load. For this analysis, 62.3% of total demand was assigned to base load, 29% to intermediate load, 7.4% to daily peak load, and 1.3% of total demand to seasonal peak load. For the complete methodology and references for deriving these percentages, refer to Appendix H.

As expressed by the following equation, the model was required to procure a minimum amount of electricity that was demanded during each load:

$$\sum_i e_{ij} \geq d_j \quad (\text{Equation 2})$$

where:

d_j = demand for electricity during load j (MWh)

e_{ij} = electricity produced by technology i during load j (MWh)

Constraint 2 – Physical Capacity

The amount of available capacity for each generating technology was based on the existing capacity within the state, the amount of capacity that has been proposed (in the form of responses to Energy Commission RFPs), and the potential capacity in the state (based on estimates given by the Energy Commission). The existing capacity was used as a baseline of existing generation potential and was subject to a retirement rate of 2.5% per year, based on the average of expected retirements of California power plants in the next three years [25]. The following discusses the origin of capacity data for existing,

proposed, potential, and imported capacity. Assumptions regarding the capacity factors for each technology are also discussed.

When operating the model, it was necessary to base the existing capacity for all technologies on capacity in years prior to each scenario run for the years 2005, 2010, and 2015. The assumption was made that energy contracts would be eight years because of SEP eligibility rules. Since the number of contracts directly impacts the amount of capacity required to satisfy the contracts, a baseline year was established for each run. For the year 2005, it was assumed contracts began in 2003 (beginning of RPS); for the year 2010, the baseline year was 2003 (8 years prior); and for 2015, the baseline year was 2008 (also 8 years prior). As a consequence, the model creates a baseline of existing capacities from the earliest year in which renewable projects could claim SEPs. The result was that the model calculated the total amount of renewable energy corresponding to the number of claims on the fund during a given year.

Existing Capacity Data – The existing capacity for all technologies was based on the capacity of existing facilities as listed in the Energy Commission’s 2001 Database of California Power Plants (note that non-IOU serving facilities were removed) [26]. The list was updated with additional capacity since 2001, as provided by the Energy Commission’s “Facility Status” website [27].

Proposed Capacity Data – The proposed capacity for conventional technologies was taken from the Energy Commission’s Energy Facility Status [27]. The proposed capacity for renewable technologies was taken from the Energy Commission’s Renewable Resources Development Report [2]. According to Public Interest Energy Research Group (PIER), the data for currently “proposed projects” was based on responses to the Energy Commission’s first round of RFPs [28]. Based on the assumption that many of these projects are unlikely to be constructed, half of this capacity was arbitrarily removed as potential projects for 2005.

Future Potential Data – Determining the development of long-term conventional generation was not a question of how much, but rather of which technologies will be built. This is because the future of conventional projects depends more on market factors and the political climate and less on the physical potential of conventional energy sources. The WECC’s 10-year Coordinated Plan Summary expects combined-cycle combustion turbines to be the dominant generating technology that is built in the next ten years in California.[19]. Although the same report was not as optimistic about the future of single-cycle facilities (the construction of single-cycle facilities was not anticipated after 2002), the Energy Commission has nonetheless issued numerous RFPs for peaker-plants. The Coordinated Plan Summary predicts that no coal, nuclear, or large hydroelectric projects will be built in the next 10 years. Little potential for coal and nuclear projects is likely based on public concerns, air quality laws, and the absence of RFPs issued by the state. Likewise, little potential for large hydroelectric projects is likely due to environmental concerns and a lack of available sites for new projects.

The future potential capacity for renewable technologies was based on data taken from the Energy Commission's RRDR [2]. These data were submitted by PIER¹⁷ and capture the technical potential for renewable projects in California. The PIER data included filters that excluded certain areas from consideration based on land use. These exclusions consist of coastal zones, sensitive habitat, 200-meter buffers from streams, forest, water, wetland, urban areas, reserves, and areas with greater than 20% grade. Based on conversations with PIER, these filters were not perfect and may have failed to exclude substantial resource areas. The wind data indicate areas with a wind power density of greater than 500 W/m² and a velocity greater than 7.5 meters per second at a 70-meter hub height. As a result, the wind data were not divided into classes. Based on a visual approximation of the wind zones depicted on a map in the RRDR, 66% of the zones were assumed to be Class 5 wind and 33% were assumed to be Class 6 wind.¹⁸

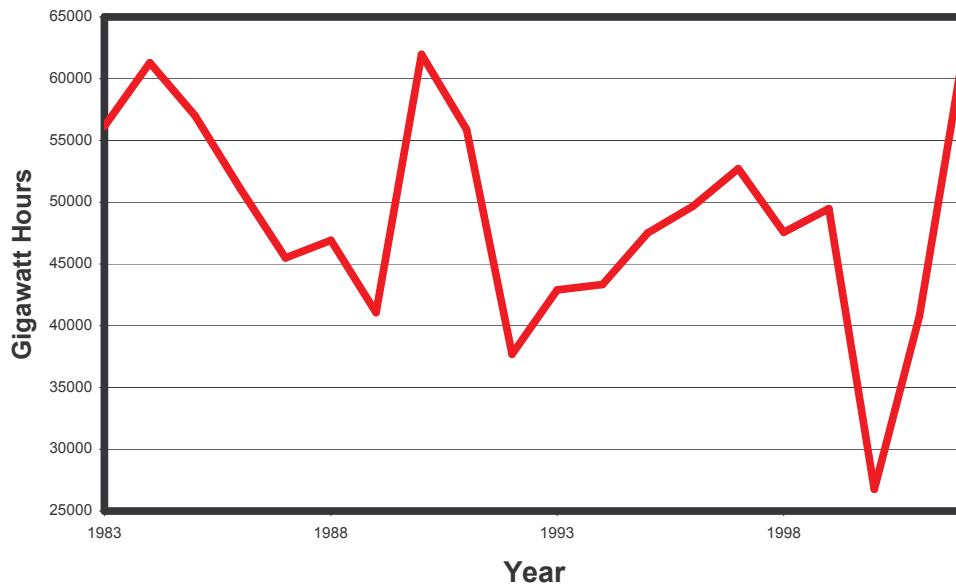
The PIER renewable potential data does not include a filter based on economic feasibility. In the case of wind, which has over 17,000 MW of technical potential in California (not including existing capacity), the major economic variable was the cost of transmission. This was especially true for areas of wind that are distant from all existing transmission lines. The initial cost of connecting a remote location to the grid is almost entirely borne on the first developer, which discourages early entry. While the potential for wind in California is great, it was assumed that a substantial percentage of the technical potential would not be developed due to the aforementioned burden of connecting transmission. Based on this observation, 20% of the technical potential was arbitrarily excluded for Class 6 wind and 30% of the technical potential was excluded for Class 5 wind.

Imported Electricity Data – The model limits the amount of available imported electricity based on historical imports to the state. Averaged total utility imports of electricity from 1999 to 2002 (excluding 2000 as an outlier) were used to determine the model's upper limit for imports (Figure 3-1). California Independent System Operator (CAISO) hourly data from August 1, 2002 to July 31, 2003 were collected to construct a LDC for imports [29]. The total imports for each load (base, intermediate, daily peak, and seasonal peak) are a percentage of the total demand for imports and were based on the shape of the LDC (for more details see and Appendix H). Each import load was treated as a separate technology within the model.

¹⁷ PEIR provided the data for this portion of the Renewable Resources Development Report.

¹⁸ Wind resources are expressed in terms of wind power classes, ranging from class 1 (the lowest) to class 7 (the highest); each class represents a range of mean wind speed at specified heights. Sites with class 3 designations or higher are suitable for most wind energy development, whereas class 2 sites are marginal and class 1 areas are typically unsuitable.

Figure 3-1: Electricity Imports to California



Capacity Factor – The capacity factor (also referred to as “availability”) for existing technologies was not based on published values, but rather was based on the amount a specific technology generates during a typical year given a specific amount of capacity. The intention of this calculation was to capture the reality of each technology’s generation capacity, rather than its theoretic capability. To this end, the total generation for specific technologies during 1997 was divided by the capacity of those technologies during the same year.¹⁹

Because this same approach cannot be used for projects that are not yet built, the capacity factor for new technologies was based on published values.

Constraint 3 – Physical Capacity Considering Load Multiplier

The capacity necessary for base load can be calculated by dividing total generation during that load by the number of hours in a year (8,760). However, due to the inherent stand-by time required for facilities that provide intermediate and peaking power, it is necessary for these facilities to have additional capacity (MW) available in order to meet annual electricity demands. Therefore, the calculation described above cannot be used to find the total capacity necessary for non-base load facilities. Instead, each load (j) was designated with a capacity “multiplier” (also called the “load factor”; see Appendix H for

¹⁹ The year 1997 was chosen because data for both capacity per technology in California and generation per technology in California was available. Sources for data: California Electrical Energy Generation, 1983 to 2002, Total Production, By Resource Type, <http://www.energy.ca.gov/electricity/index.html> > 1983-2002 California Electricity Generation and California Energy Commission, Siting and Environmental Protection Division, Power Plant Database, <http://www.energy.ca.gov/database/powerplants>

details), which is the inverse of the percentage of time each load j operates during an average day [30]. In the model, this equation was expressed as:

$$\sum_j \frac{e_{ij}}{L_j} \leq a_i R_{ij} * 8760 \quad (\text{Equation 3})$$

Where:

a_i = availability of technology i (unitless)

R_{ij} = capacity of technology i during load j (MW)

L_j = load factor: the percentage of time that load j operates (unitless)

e_{ij} = electricity produced by all eligible renewable technologies during all loads

8,760 = total number of hours in a year (hours)

$(a_i R_{ij} * 8760)$ = the actual available capacity for technology i during load j for one year.

$\sum_j \frac{e_{ij}}{L_j}$ = the amount of capacity required by load j .

For example, in order to produce some number of megawatt-hours during a peak load where the load factor is 1.3%, a plant needs approximately 77 times more capacity than if it were given the whole day to produce the same amount of electricity.

This physical constraint prevents the model from exceeding the available capacity for any given technology, while satisfying the total capacity required from the load factor calculation.

Constraint 4 – RPS Requirement

The three major utilities entered the first year of the RPS with a collective 11.4% baseline [2]. Per RPS rules, the model starts with the 11.4% baseline and “ramps up” the required amount of renewable electricity procured by the IOUs by 1% for every year thereafter.

$$\sum_{ER_i} \sum_j e_{ij} \geq R \quad (\text{Equation 4})$$

where:

R = renewable generation required by the RPS (MWh)

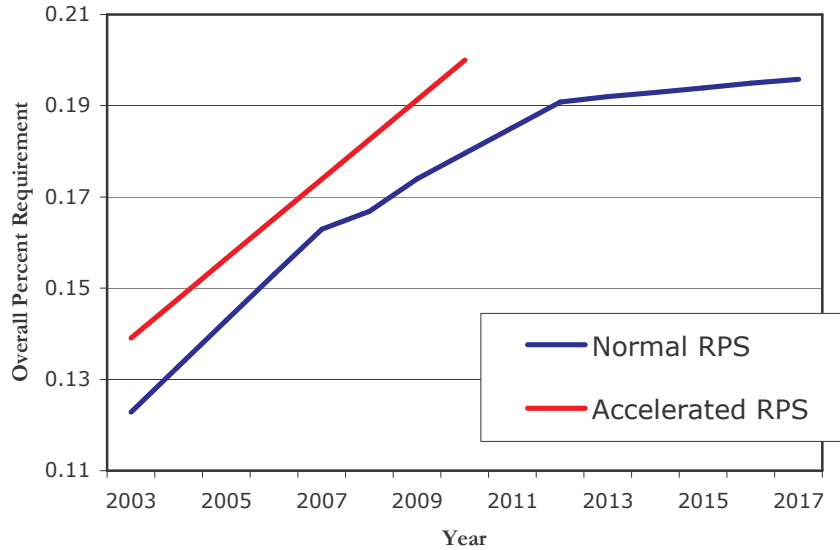
e_{ij} = electricity produced by all eligible renewable technologies during all loads

ER_i = eligible resource technology i

It would be an oversimplification to simply add an annual 1% to the baseline until the 20% has been met due to the fact that each IOU has a different baseline and represents a different proportion of the total electricity production. As a result, a weighted RPS was

calculated that was based on each IOU’s baseline and its relative energy production, as done in Appendix A of the RRDR. The results can be seen in Figure 3-2 below.

Figure 3-2: Collective RPS Ramp-Up Requirements, Accelerated and Normal RPS



Constraint 5 – Hydroelectric Constraint

Although hydroelectric dams have a large capacity, their ability to generate electricity is limited by water storage. As a result, the amount of hydroelectric electricity that the model can procure is limited by the historical production of hydroelectricity between 1983 and 2001 [31]. Equation 5 expresses that the amount of electricity produced from hydroelectric sources must be less than or equal to the limitation imposed based on that historical data.

$$\sum_j e_{hj} \leq m_h \quad (\text{Equation 5})$$

where:

- e_{hj} = electricity produced by hydroelectric technologies over all loads (MWh)
- m_h = Electricity output cap imposed on hydroelectric power (MWh)

Assumptions

This analysis assumes that the total direct costs of the RPS to be paid from ratepayer public goods charge funds will, at a *minimum*, be equal to the total above-market costs of renewable energy that are incurred by the RPS. The model calculates the costs of capital, O&M, and transmission interconnection; however, it *does not* include the cost of transmission service.

The length of time that an eligible renewable generator is allowed to claim SEPs will also have a great impact on the calculation of total direct costs. Renewable generators must secure a minimum three-year contract in order to be eligible for SEPs, and are permitted to claim payments for a maximum of ten years. This analysis assumes that the average length of contracts will be eight years based on generator’s motivation to remain eligible for SEPs and the IOU’s motivation to remain compliant with the RPS. This is significant because a generator that receives a SEP in one year will continue to make claims every year for the next seven years. Therefore, during any given year the fund must support all of the claims that remain eligible from the seven previous years as well as the new claims for that year.

Table D summarizes other assumptions made regarding the market, data, and state regulations. Further discussion of each item is available in Appendix E.

Table D: Model Assumptions

Market Assumptions	Model Assumptions	State Regulation Assumptions
<ul style="list-style-type: none"> • No market powers exist • No external market forces • IOU compliance • Perfect knowledge 	<ul style="list-style-type: none"> • Near-term capacity expansion limits • Long-term conventional potential • Long-term renewable sources • Length of renewable contracts • Hydroelectric generation limits • Load factor • Grouping average costs of electricity generation 	<ul style="list-style-type: none"> • Incorporates most decisions finalized during Phases 1 and 2 • Pending CPUC decisions are final • Only in-state renewable projects included • 3 IOUs do not own or operate renewable projects

3.2.3 Running the Model

The model was run with multiple scenarios using the variables discussed below. In total, twenty runs were performed: twelve for the normal RPS (four scenarios, three years) and eight for the Accelerated RPS (four scenarios, two years).

Scenarios

The model's scenarios were comprised of four variables:

- *Year* – The model was run for the years 2005, 2010, and 2015. Each of these years has specific data associated with it, including, but not limited to, the forecasted demand for electricity, the level of the RPS requirement, and the forecasted price of natural gas.
- *RPS Type* – Both the standard and accelerated RPS target goals were considered.
- *Natural Gas Prices* – Based on projected prices of natural gas from the Energy Commission and Energy Information Administration, a high and low cost of operation and maintenance for both single cycle and combined cycle combustion turbines were forecasted.
- *Federal PTC* – The cost of new wind projects was calculated with and without the subsidy of the federal production tax credit (PTC).

Each scenario produced a percentage of the renewable energy procured, the capacity of each technology required, the expected electrical production of each technology, the total expected cost to the fund, and the shadow price of the RPS mandate.

3.3 Tradable Renewable Energy Credit Assessment

Since tradable REC markets are a recent development, there is little available empirical information for analysis. Thus, this part of the project relies largely on a qualitative assessment of existing TREC market, policy, and data information collected via literature review and stakeholder interviews. This section first provides an analysis of the distinguishing characteristics of TREC markets, exploring the impacts of the market size, pricing, and title ownership issues; it next analyzes existing market data to the extent possible, and finally, it reviews other state experiences with TRECs.

3.3.1 Market Characterization

Emerging Environmental Markets

An emerging environmental market has been generally characterized to exhibit five principal traits. First, there is a heightened potential for market manipulation. Second, credit traders are reluctant to enter a market clouded with uncertainties, resulting in a

small number of participants. Third, delays are expected in the proper functioning of market processes, such as certification, tracking, and verification systems. Fourth, perception of supply and demand drives price. Fifth, existing players have greater influence in the early stages, which wanes as more participants enter the market.

While the five environmental market characterizations may generally apply to the newly emerging TREC markets, it is important to note that they differ from other better understood environmental trading markets in several fundamental ways. Specifically, the overall size of the TREC market is unknown, as it is a function of two variable quantities: the actual renewable generation and the actual retail sales. Since TRECs are bought in proportion to a variable demand, the resulting number of TRECs is also variable. Another distinction of the TREC market is that renewable energy suppliers cannot quickly respond to short-term variability and risk. Demand is largely a function of economic activity and weather, whereas supply is largely determined by the current physical capacity. While the weather may suddenly change and the economy fluctuate, most renewable projects require at least a year's lead-time to construct [16].

These market generalizations are key to understanding the framework within which a TREC market might operate. A limited short-term experience with TREC markets is available and useful for adding layers to this framework, providing lessons that may hold true through time and across regions. Recent experience has shown that in the short-term: (1) exercise of market power by existing, large suppliers can occur; (2) regulatory uncertainty can cloud market decisions; and (3) delays in getting the market operational (granting accreditation and creating new certificates) can stifle quick progress. Interestingly, the lessons emerging from recent experience with trading TRECs do not differ from those describing all emerging environmental markets.

Though these factors will likely lead to an unstable market in the short-term, it is expected that prices would stabilize in the long-term according to basic supply and demand drivers. Within-year variation, however, is expected in both the short- and long-term due to the intermittent nature of much renewable generation. The potential for price instability and market uncertainty can be mitigated with the inclusion of flexibility mechanisms, such as banking of TRECs.

Impacts of Selected Market Size

According to Robert Grace and Ryan Wiser in *Transacting Generation Attributes Across Market Boundaries*, markets can be characterized by the following four sizes: unconstrained market area, super-market area, market area, and sub-market area. Determining the appropriate size of a TREC market depends upon the objectives of that market, as determined by policy. While some markets are designed to achieve local environmental and economic objectives, others are intended for national or global objectives. Of equal significance, the selected size will influence future market volatility [13].

Some state RPS programs may be better served through a market or sub-market area, as they are ideal for programs that are designed to achieve local objectives and are situated within a large resource region. Grace and Wiser explain that utilizing a sub-market area approach for a state RPS mandate “could assure both local economic benefits and displacement of local fossil generation.” In contrast, unconstrained and super-market areas benefit programs designed to achieve regional and national objectives, such as regional air pollution reduction to counter acid rain or carbon dioxide emission reduction to further global climate change initiatives.

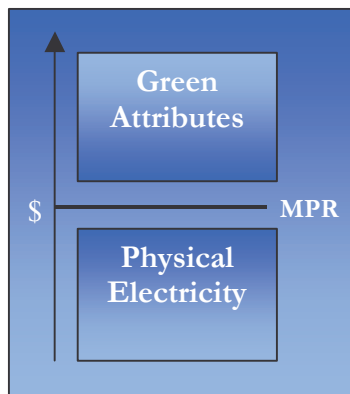
The design of market size also impacts the degree of market volatility, which is a function of the fluctuations in production and imperfect information regarding supply and demand. For example, smaller markets are more physically limited in their supply of renewable energy generation potential and thus are more sensitive to inter-annual seasonal variation, escalating the potential for price volatility. By expanding the size of the market, the resource base is proportionately expanded, which ultimately serves to stabilize market prices. Stabilized prices reduce risk, resulting in increased participation in the market and improved compliance levels.

While larger markets may serve to reduce program compliance costs and decrease market volatility, they may also stifle renewable development in certain areas because of disproportionate support for projects. For example, if renewable development was more heavily subsidized in one region, it would out-compete the development of unsubsidized renewable energy in other regions. As a consequence, larger TREC markets may prevent local communities from capturing the same level of economic and environmental benefits enjoyed within a smaller market.

Whether large or small, a TREC market should be designed to reflect the goals of the specific program, taking into account possible side effects resulting from the design decision.

Determinants of Price

The price of a TREC is often described as being equal to the difference in price from renewable and conventional resources. However, this simplistic price description fails to account for the uncertainties invariably created by the emergence of two separate markets: the energy market and the TREC market. It may seem safe to assume that in a



competitive market, a utility is unlikely to pay more than this premium for a TREC if it had the option of generating the electricity itself or purchasing from another party, and conversely it is unlikely a seller would accept less than the above-market costs (if such costs exist) because it would not recover sufficient revenue to cover costs of generation. However, situations do exist in which this assumption will not hold true. As pointed out in the CPUC June 2003 Rulemaking, “A generator may bid its energy and environmental attributes at a price

below the market price referent, or a generator may bid above the market price referent based solely on its operating costs. It is up to the generator to decide how much its environmental attributes are worth, how much it wants to bid into the RPS program for its energy and environmental attributes, and even if it wants to bid at all” [9].

While impossible to predict exact prices, the price of TRECs are expected to be chiefly a function of the cost of supply of renewable energy, the demand based on the level of the mandated target, the structure of the wholesale electricity market, and the market for TRECs [14]. It is anticipated that the price will generally be equal to at least the above-market costs (if such costs exist) for the project to be economically viable for the generator. However, this may not always be the case. The market-clearing price for TRECs is also expected to equal the levelized cost of the TREC from the marginal renewable energy source required to meet the target, assuming a competitive market with fully informed participants. This could change if banking were allowed because the current prices would reflect the expectations of future prices.

In addition to basic supply and demand forces, a number of factors affect the price of renewable energy, and ultimately the price of TRECs. This discussion follows.

- *Differences between Renewable Resources* – The price will reflect, to a degree, the economics of the type of renewable technology used to produce the TREC. For instance, the cost of generating 1 MWh of solar electricity is more than that from wind.
- *Generation Location* – Even when comparing the same technology, the price will reflect the location’s energy potential (e.g., class of wind available) and its distance from transmission, as they affect the economics of development, production, and distribution.
- *Contract Specifics* – In general, since part of the total cost of a transaction is fixed, the larger the purchase volume, the lower the unit price becomes. Longer-term contracts also tend to drive down the unit price.²⁰
- *Maturity of Market* – When TREC markets mature, they are expected to increase market transparency, with the impact of either increasing or decreasing prices.
- *Market Power* – If existing generators significantly influence the market, large suppliers of TRECs have the potential to support higher prices.
- *Price Cap* – A non-compliance penalty often serves as the ceiling for TREC prices if the obligated entities cannot buy their way out of their obligation via a penalty mechanism. This has been the case in Massachusetts for which the price of TRECs has steadily increased towards the penalty price since the opening of the market.

²⁰ This report is unable to quantify the effects of long-term contracts on the price of TRECs; further analysis is needed.

Future prices will be influenced by both the aforementioned factors and additional market uncertainties. Each of the following seven uncertainties will likely factor into each participant's assessment of market risks, and each has the potential to impact TREC prices to a varying degree and for a length of time. For instance, the uncertainty stemming from the uncertain future structure of the wholesale market (e.g., regulated versus deregulated) is likely to be more infrequent, but perhaps more pronounced than is the uncertainty stemming from regularly fluctuating electricity prices. It is likely, however, that a stable electricity market will positively impact a newly formed RPS market. Following is a brief discussion of seven market and regulatory factors that will invariably impact the renewables market, and consequently TREC prices.

- *Wholesale Market Price Uncertainty* – This uncertainty stems from changes in the market price of electricity and may impact a generator's willingness to enter the market. With cheaper wholesale electricity prices, above-market costs become more significant and prone to greater risk. A plausible situation could be that as fewer generators enter the market, supply shrinks, demand continues to grow because of the mandate, and prices for renewable products increase.
- *Regulation of Wholesale Market Uncertainty* – Deregulated states allow consumers to choose their source of electricity, many offering green power programs.²¹ These green power programs typically vary in their degree of magnitude of effect on renewable markets. It is unclear how an increased consumer demand for renewable products would pressure the voluntary and compliance TREC markets.
- *Cost of Renewable Generation Uncertainty* – Technology and fuel costs are subject to fluctuation and cannot be accurately forecasted. However, with continued investment in the renewable sector, it is likely that technology costs will drop, whereas fuel costs will remain dependent on secondary market activity.
- *Renewable Energy Supply Uncertainty* – Environmental, economic, or technical circumstances could limit further development of renewable resources. Were supply constrained while demand increased, the prices of renewable products, such as TRECs, would also likely rise.
- *Regulatory Uncertainty* – Rules are subject to change, as they are reflective of the political climate and other stakeholder influences. Funding can be supplemented or stripped for RPS compliance; similarly, targets can be increased or decreased. Compliance mechanisms will not likely change as readily, but it is feasible that they could be changed before full implementation of the RPS is complete. It is unclear how this will affect TREC prices, other than making market activity unstable.

²¹ According to the Energy Information Administration, 18 states have been restructured; five states have delayed restructuring; one state (California) has suspended restructuring; and 26 states do not have any restructuring activity.

- *Demand Uncertainty* – Changes in the market size can affect the level of demand for renewables. Changes in demand could result from the creation of new policies such as an RPS, expanding eligibility to include out-of-state resources, instituting a voluntary green power purchasing program, or encompassing more parties under the mandate’s umbrella. Depending upon which is more favorable – bundled or unbundled contracts – the TREC market would be affected by how actively credits are traded.
- *Regional Market Uncertainty* – Similar to the comments regarding changing levels of demand, it is possible that markets could expand to a regional or national level, affecting both supply and demand of TRECs and influencing prices. Additionally, it is possible that TRECs will be included in a carbon trading market.

Again, since the existing TREC markets are new and there is little experience upon which to draw consistent lessons and conclusions, it is nonetheless important to highlight the factors that will likely impact future TREC markets. As markets mature and time progresses, trends will become identifiable and useful for future planning.

Property Rights and PGC Funds

Many states differ in their methods for discerning TREC ownership when public funds are used. The use of public goods charge (PGC) funds to subsidize the development of renewable energy further complicates the issue of determining which entity owns the generated TRECs. States that allocate PGC funds for renewable projects have utilized some of the following approaches in order to address TREC property rights: (1) providing incentives to sell TRECs directly to end-use customers within the state; (2) developing TREC education campaigns; (3) creating TREC accounting and verification systems; (3) restricting the use or sale of TRECs from subsidized generators; (4) requiring state ownership of TRECs; and (5) developing projects to minimize TREC price fluctuations [32].

Some states that use PGC funds to subsidize the development of renewable projects may claim ownership of the TRECs that were generated from subsidized projects. According to Fitzgerald, Wiser, and Bolinger, there are several reasons why states maintain TREC ownership [32]. First, states such as Oregon want to ensure that the benefits of renewable energy are retired on behalf of the state ratepayers. Second, states such as Connecticut want to use TREC sales as a source of revenue for ratepayer funds. Third, states such as New Jersey want to protect the state against project developers who default on their financial commitments. Fourth, states such as Massachusetts want to support renewable projects and facilitate project financing by hedging against fluctuations in TREC prices.

There are currently five states that restrict the property rights of their TRECs. These include Massachusetts, Rhode Island, Wisconsin, Minnesota, and New Jersey. The following is a description of the property rights characteristics of each state [32].

- Massachusetts requires that 30% of the TRECs from a project subsidized with PGC funds must be sold within the state's market for the first ten years of the project's life. The state also guarantees the purchase of TRECs from funded projects at a certain price (e.g. \$20/MWh) [33]. Developers can choose whether to sell their TRECs within the state marketplace or to sell them back to the state. TRECs purchased by the state will be resold into the market as an additional source of revenue.
- Wisconsin has a similar requirement, in which projects that receive PGC funds cannot sell their TRECs for state RPS compliance purposes for the first ten years of the project's life.
- Rhode Island has a more stringent requirement that does not allow any TRECs originating from subsidized generators to be sold outside of the state. In addition, projects that receive PGC funds can only sell a maximum 75% of their generated TRECs, while at least 25% must remain with the generator.
- In Minnesota, renewable projects that receive funding from the Xcel Energy Renewable Development Fund must sell their generation back to Xcel. Because Xcel has ownership of all renewable attributes, it may choose to sell TRECs as an additional source of revenue.
- New Jersey grants all REC property rights to the project developer. However, ownership of RECs will revert back to the state if the developer fails to meet financing commitments.

Other states may implement similar methods to restrict TREC property rights. However, these states are not mentioned above because they either do not have an RPS, or their restrictions apply to selective market participants.

3.3.2 Other State Experiences

The following discussion highlights the primary drivers for and objections to TREC implementation within specific RPS programs. The discussion focuses on Arizona, Connecticut, Maine, Massachusetts, Texas, and Wisconsin, and also summarizes the use of TRECs in Australia's RPS. This section relies largely on personal communication with stakeholders in each respective state and the report *The Experience of State Clean Energy Funds with TRECs*.

Arizona

TRECs were integrated into the Arizona RPS to provide utilities with a low cost mechanism for compliance. It was hoped that they would offer utilities the flexibility to either procure renewable electricity or to purchase credits. There was general support for the implementation of TRECs within Arizona. First, they were favored by utilities because they offered a potentially low cost alternative to self-generation. Second, renewable generators favored them as a means for expanding the market [34].

Connecticut

Connecticut implemented TRECs into its RPS for several reasons. First, the Connecticut Clean Energy Fund believed that TRECs would facilitate the financing and construction of new renewable technologies [32]. Second, TRECs have become an additional source of revenue for the state [32]. Third, there is a general concern regarding the future supply of renewable energy in New England. Because of the increased demand for renewable energy resulting from the Massachusetts RPS, Connecticut is being proactive in its use of TRECs. Fourth, there is a better source of renewable resources in adjacent power pools such as NYISO and PJM. Consequently, TRECs may be a less costly form of RPS compliance for the Connecticut ratepayers. Fifth, Connecticut is involved in the construction of renewable projects in other states, and would like to apply these RECs towards its RPS program. There is general support for TRECs within Connecticut. While some environmental groups were concerned about the distribution of renewable attributes, these groups now support TRECs as a method to reduce greenhouse gas emissions both nationally and globally [35].

Maine

Maine adopted a region-wide TREC system in 2002 with other participants in the New England electricity market. There were three primary reasons for choosing TRECs [36]. The state wanted to create a secondary market for the attributes of renewable electricity. Maine also wanted to substantially reduce the generators' cost of compliance with the variety of state RPS requirements in New England. Finally, the state realized that TRECs facilitate compliance and verification efforts, which would otherwise be difficult in New England. No known parties were opposed to the implementation of TRECs in Maine [36].

Massachusetts

Massachusetts incorporated TRECs into its RPS program because it recognized the benefits of having renewable attributes as a tradable commodity. However, the state's Division of Energy Resources (DOER) determined that creating a TREC program restricted to Massachusetts would be cumbersome and expensive. The DOER argued that an in-state only requirement for TRECs would impose unnecessary administrative costs on the agency and on retail electricity suppliers, and it would also impose higher costs to end-use customers. Consequently, the DOER supported the creation of TRECs that could be administered by ISO-New England and traded throughout NEPOOL [37]. In general, stakeholders supported the decision to create a NEPOOL wide TREC system [38].

Texas

Texas chose to implement TRECs in order to provide incentives for the development of new renewable projects within the state [39]. Because only facilities that were on line after September 1999 were eligible for TRECs, companies that had contracted with pre-existing facilities lobbied the Public Utility Commission of Texas to be granted offsets. These offsets cannot be traded, but can be used to reduce a utility's TREC requirements. There were no other objections to the implementation of TRECs in Texas [39]. However, virtually all of the early "trades" were long-term bilateral agreements for BRECs, indicating the importance and possible preference for bilateral contracts, particularly in the early stages of a new market [16].

Wisconsin

In Wisconsin, TRECs are used to satisfy the state's RPS program and must originate from a certified generator. Wisconsin TRECs are tied to the state and cannot be used to satisfy any other program. According to Alex De Pillis, Renewable Energy Engineer for the Wisconsin Division of Energy, TRECs were likely incorporated because of their flexibility in contrast to alternative technology-specific mandates. There were no known parties who were against the implementation of TRECs in Wisconsin [40].

Australia

The Australia TREC market for the nation's equivalent of an RPS²² opened in April 2001 as "a component of the scheme that enables the renewable energy targets to be met at least cost" [41]. Under this system, obligated parties can purchase more certificates than required, with the surplus traded to other obligated or third parties or banked for future compliance periods. With the market open a little more than a year, the experience was reported as modest because of (1) low mandate level; (2) market participants focusing on long-term strategies for entire businesses; and (3) lack of liquidity in financial market to trade TRECs.

3.3.3 Market Data

Two market participants have shared their insights on the expected behavior of tradable REC markets: Roy McCoy, manager for the Electric Reliability Council of Texas, Inc. (ERCOT) Renewable Energy Credits Program in Texas; and Tod Hynes, Business Development staff for Strategic Energy Systems, a Massachusetts TREC trader. Massachusetts and Texas are examples of two states that permit TREC trading for RPS compliance, and for which there is available market data on trends in TREC prices.

According to Hynes, basic supply and demand determines the TREC purchase price. There is currently a limited supply of TRECs in Massachusetts, which contributes to higher market prices of \$38 per MWh (see Appendix I). However, in Texas, McCoy admits that the price of TRECs is not entirely market driven, but is affected by PUCT activities and the amount of available generation. While an oversupply of Texas TRECs

²² It is called a Mandatory Renewable Energy Target.

currently contributes to low market prices of \$13 per MWh, this abundance will be mitigated with the state's upcoming 2004 interim target that increases the utilities' compliance requirements. Consequently, a reduction in the overabundant supply may also increase the future price of TRECs.

TREC prices are the same for all eligible technologies. Because there is no relationship between the price of electricity and the time-of-day in which it is generated, there is no price variation among TRECs. However, both Massachusetts and Texas have strict requirements on the eligibility of TRECs, which serve to isolate each state's RPS and contribute to a difference in the TREC prices for each region. For example, McCoy states that no other mandatory RPS programs allow the use of Texas TRECs for compliance.

Since the inception of these markets, there has been great fluctuation in the price of TRECs. Much of this can be attributed to early speculating, in which utilities "shopped around" until prices stabilized. Despite their volatility, TREC prices are essentially capped in Massachusetts and Texas, due to a maximum non-compliance penalty of \$50 per MWh. Generators have also been willing to arrange long-term contracts at lower prices in order to guarantee project financing. According to Hynes, some three-year contracts are selling TRECs for \$25 to \$30 per MWh. Texas also has the majority of its TRECs sold under long-term contracts.

In Massachusetts, the beginning of the market saw conservative TREC contract prices of \$25 per MWh due to the uncertainty of the new market. These prices have continued to rise to the observed current prices of \$35 to \$40 per MWh, with solar being priced as high as \$60 per MWh. The greatest contributor to unstable TREC prices in Massachusetts is a lack of supply. While a new Cape Wind generation project was proposed, adding 420 MW to the grid, the uncertainty surrounding the status of this controversial project has contributed to price volatility within the market.

Texas has also seen fluctuation in its TREC prices as the market has developed. In its initial stages, market participants expected TRECs to sell for approximately \$0.50 per MWh. While this was an underestimate, TRECs were conservatively priced at \$2.50 per MWh. However, prices quickly rose during the first compliance period to \$20 per MWh, although no TRECs were sold at these prices. Current market prices have finally stabilized between \$12 and \$15, and the average "last price" for July 2003 through January 2004 was \$13.10 per MWh (see Appendix I). McCoy has observed a general trend in prices rising at the end of the year due to the pressures from looming compliance deadlines. Overall, Texas TREC prices have remained stable for the last six months. Again, McCoy foresees that prices may increase in the future due to a reduction in the excess supply of TRECs.

4 RESULTS AND IMPLICATIONS

4.1 Model Cost Results

To determine the expected cost of the RPS to the fund, the model calculated the number of renewable megawatt-hours that the RPS has forced the model to generate over the previous eight-year period (average length of contract), which it multiplied by the appropriate MPR, and finally subtracted that sum from the total cost of generating those megawatt-hours. This final cost represents the above-market costs of renewable generation, which is the expected cost to the fund during that calendar year. The model produced values which are the minimum expected costs of the RPS to the fund (explained in more detail in $Cost_{min}$ and $Cost_{max}$, below). Recall that the costs used for producing the renewable energy were based on average 2003 costs and do not reflect the expected technological improvements during the lifetime of the RPS.

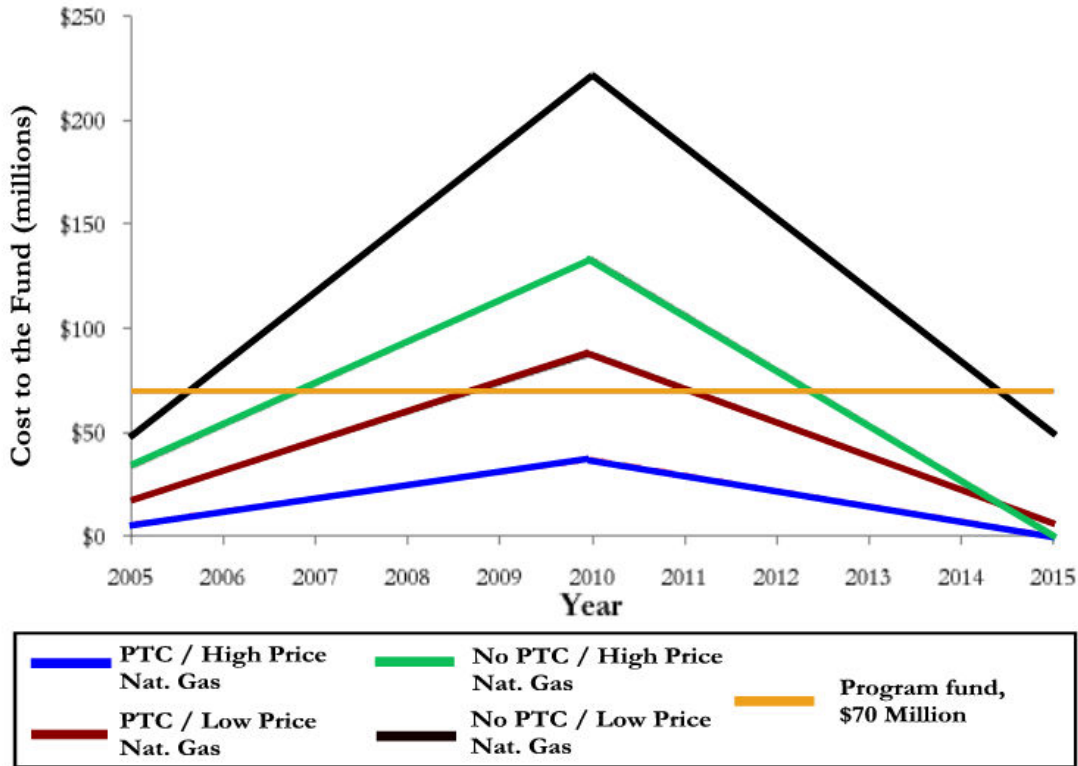
Results are divided into two categories: Normal RPS and Accelerated RPS. Since both Normal and Accelerated RPS scenarios have results based on the same dynamics, the discussion of the Normal RPS results is more explanatory and detailed, whereas the Accelerated RPS results section is abbreviated.

4.1.1 Normal RPS

The results indicate that both the future natural gas prices and the presence or absence of the PTC will affect the direct costs of the RPS substantially. The PTC, however, is a more significant factor than the price of natural gas. See Appendix E for an elaboration on model methodologies, which includes the range of natural gas prices used in the calculations.

Figure 4-1 is a graph of the total costs to the state over the lifetime of the RPS. The shape of the expected-cost curve is tented with a maximum cost in 2010. This maximum point is attributed to the cumulative nature of claims for SEPs. As explained earlier, the model assumes that the numbers of claims will build on one another until 2010, at which time the model assumes contracts from 2003 will expire. This study assumes that these renewable resources that lose eligibility for SEP payments will continue to provide renewable energy to the California energy market for the duration of the RPS program at competitive prices.

Figure 4-1: Total Costs of Normal RPS



The peaked shape of the curve can also be explained by the relative baseline of each IOU. Since SCE claimed to procure over 15% renewable energy in 2001, it will meet its 20% goal by 2007. Upon meeting its RPS targets, SCE will only be required to procure additional renewable electricity based on its overall annual growth. Assuming that its growth rate is 1.7%, SCE's APT ramp-up will decrease from 1% to 0.34% per year. PG&E claimed just fewer than 10% renewable energy in 2002. Consequently, PG&E is expected to meet its 20% requirement by 2013.

Finally, the changing level of the MPR through time can explain the shape of the curve. Whether considering a high or low forecast, the price of natural gas is expected to increase by the year 2015 (see Appendix G for the forecasts used in this analysis). Higher gas prices raise the level of the MPR, and therefore, reduce the above-market costs of renewable resources. The changing level of the MPR exposes one particular limitation of the model. Although the cost of producing conventional electricity will change through time based on the changing price of natural gas, the model does not adjust the cost of production for renewable energy sources. This is because many renewable technologies have insignificant fuel costs, and data on the expected changes in the capital costs of all of the renewable and conventional technologies were not

available.²³ The assumption that the cost of generating renewable electricity will not change in the next 12 years is arguably conservative since rapid progress is currently being made in renewable technologies. Conventional energy sources would not be expected to undergo such rapid innovations due to the relative maturity of the technologies.

The model scenario that showed the highest overall cost was characterized by low natural gas prices and an exclusion of the PTC. A low price of natural gas would impact costs by lowering the level of the MPR, which would serve to increase the above-market costs of renewable technologies. The exclusion of the PTC renders some new wind projects prohibitively expensive, forcing IOUs to utilize other, more expensive technologies to fulfill their mandate. In contrast, the scenario that included the PTC and high natural gas prices showed the lowest overall cost to the fund. A high natural gas price would raise the level of the MPR, which would serve to decrease the above-market costs of renewable technologies. The inclusion of the PTC also provides financial incentives for the development of new wind generation.

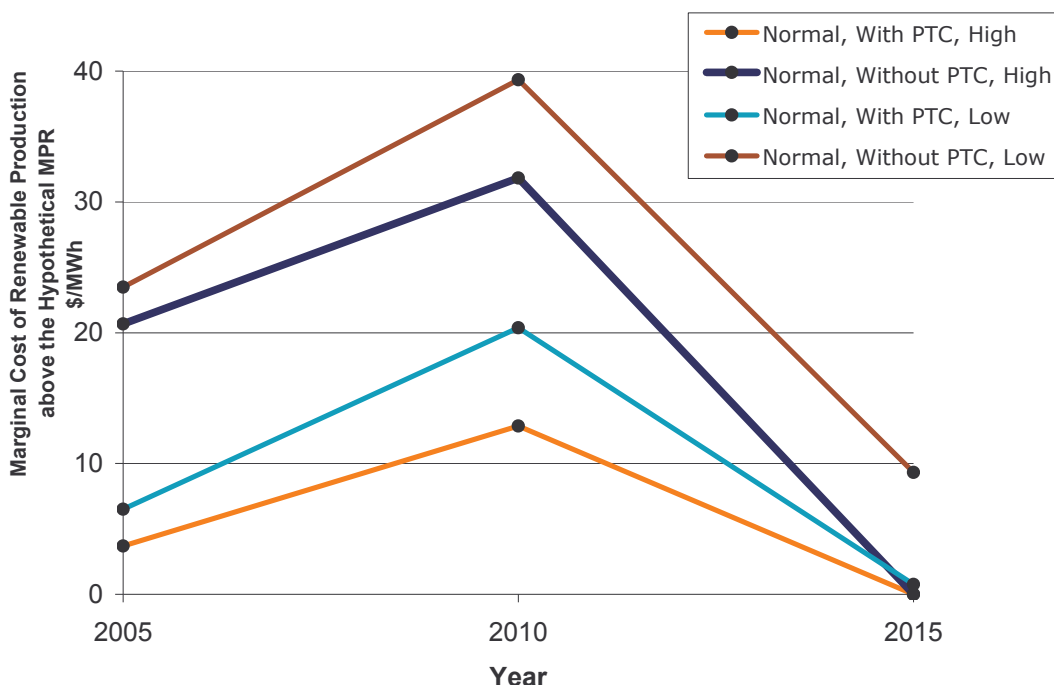
The horizontal line in Figure 4-1 is a point of reference that represents the size of the fund (\$70 million annually), and signifies the point at which the state can no longer afford to allocate SEP payments. The costs of the program that exceed this line will exceed the state's available funding, and represent years in which IOUs will only be responsible for procuring the fraction of their APT that can be reimbursed by SEPs. The only scenario that remains entirely within the limits of the \$70 million fund is characterized with a PTC and high natural gas prices. The model, therefore, predicts that the RPS will only have sufficient funding to meet its goal if the PTC is reinstated and if natural gas prices increase.

It is notable that when the model is run for 2015 with the high natural gas price forecast and the PTC, the amount of renewable electricity procured jumps to 25% (even though the requirement is only 20%). See Appendix E for a table of the natural gas price forecasts used in the model. This is attributed to the fact that when there is a PTC in addition to high natural gas fuel prices, Class 6 wind becomes more cost-competitive than combined-cycle natural gas generation.

The model-generated shadow prices for the various scenarios during the normal RPS ramp-up schedule are presented in Figure 4-2.

²³ The Energy Commission's *Renewable Resource Development Report* contains projections for future O&M and capital costs for a select group of renewable technologies, but does not include all renewable technologies chosen for this study. In addition, projections for conventional technologies were unavailable. Therefore, this study utilizes constant prices for the various model years studied.

Figure 4-2: Expected Shadow Prices of Normal RPS



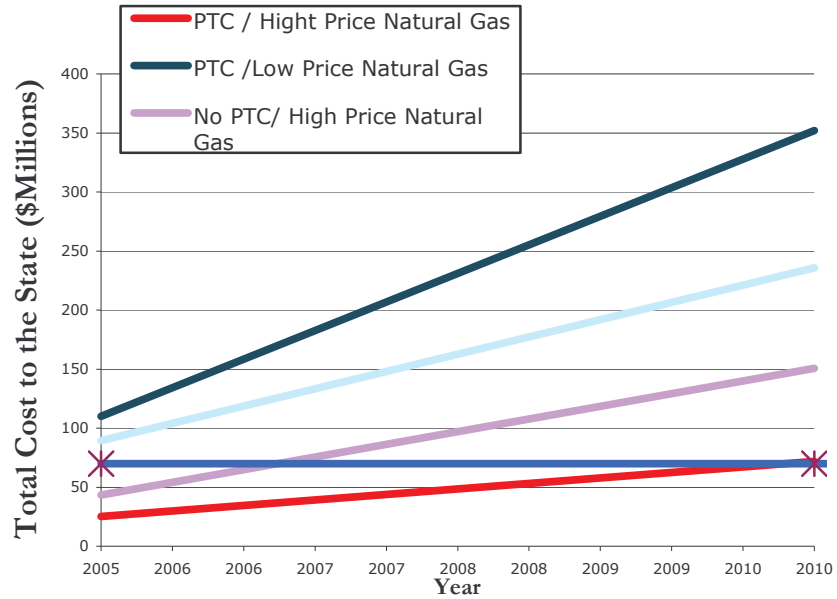
As explained earlier, the shadow price is the above-market cost to the state if one additional megawatt-hour is required by the RPS. The shadow price is equal to the above-market marginal cost of renewable production in a market where the RPS drives the demand for renewable resources. In a competitive market, this shadow price would theoretically be the market price for the good (in this case it is the premium for renewable electricity). The highest shadow price produced by the model was \$40 per MWh during 2010. The lowest shadow price was \$0 per MWh during years when the marginal cost of producing renewable energy was at or below the MPR.

4.1.2 Accelerated RPS

The model was also run with the RPS requirements accelerated such that the IOUs are required to procure 20% renewable electricity by 2010 instead of 2017. Recent conversations with the Energy Commission indicate that the Accelerated RPS is being considered seriously.

The expected costs of the Accelerated RPS program are presented in Figure 4-3 and the associated shadow prices are in Figure 4-4.

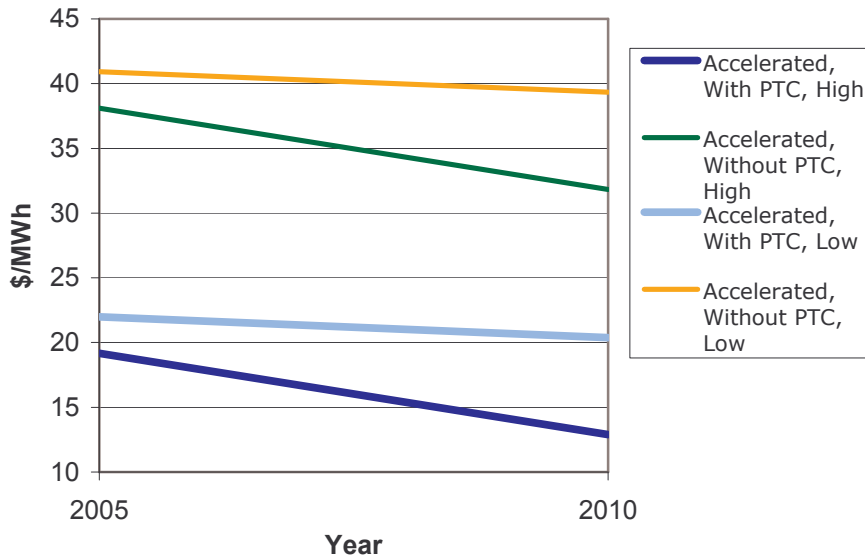
Figure 4-3: Totals Costs to the State of an Accelerated RPS 20% by 2010



Under the Accelerated RPS, the costs to the fund are expected to increase steadily from year to year until the overall goal has been met in 2010. The curve is straight because there are only two points (2005 and 2010). Had there been more points along the graph, the curve would have been steeper until 2008, at which time SCE would have met its procurement target. After 2008, the line would have flattened slightly to reach the same cost in 2010, as depicted in Figure 4-4.

Again, the only scenario that remains below the \$70 million fund limit is characterized with a PTC and high natural gas prices.

Figure 4-4: Expected Shadow Prices for Accelerated RPS



4.1.3 $Cost_{min}$ and $Cost_{max}$

The following three graphs and discussion are presented in order to capture two concepts that are critical to understanding the analysis of the results: $cost_{min}$ and $cost_{max}$. In brief, $cost_{min}$ is the minimum cost to the state as calculated by the model and $cost_{max}$ is the maximum cost. As explained earlier, these costs do not include the cost of transmission service.

Figure 4-5: Supply Curves for Renewable Energy Supply Based on Normal RPS Requirements, 2010

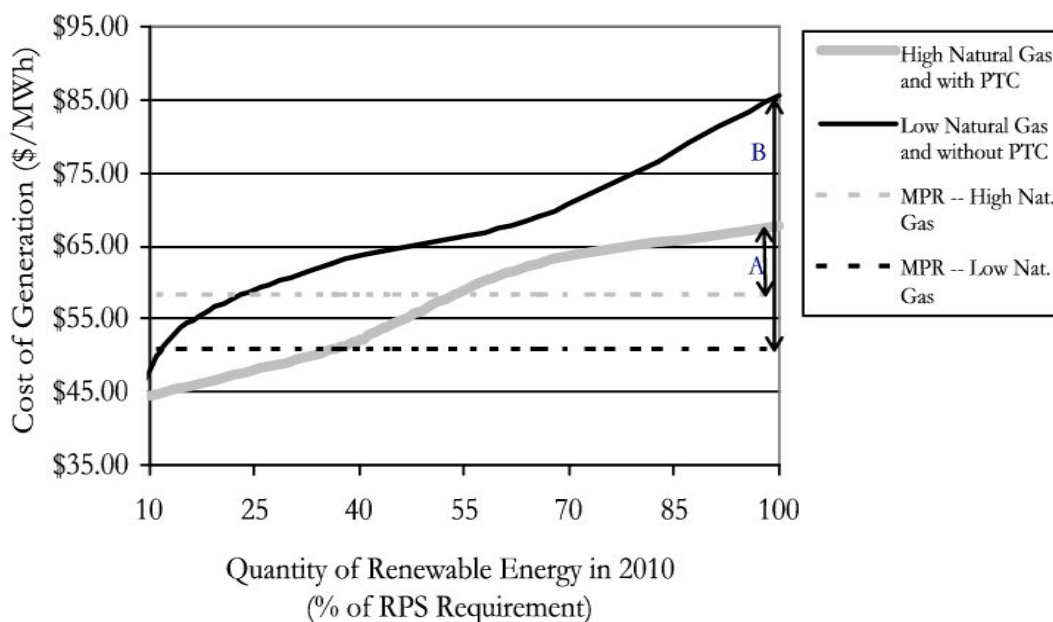


Figure 4-5 shows two supply curves for renewable energy in 2010 (year chosen arbitrarily) given two different scenarios: (1) a high price of natural gas and inclusion of the federal PTC, and (2) a low price of natural gas and exclusion of the federal PTC. These two scenarios were chosen because they represent the two extremes in forecasting the expected cost of the RPS: the least costly and most costly model scenarios. However, the likelihood of the CPUC approving either contract scenario remains unknown, as the agency's case-by-case evaluation of a renewable energy resources solicitation is based on its consistency with the renewable procurement plan. The solid curved lines represent the supply curves for renewable energy for each respective scenario; the dashed horizontal lines represent the expected MPR associated with the respective natural gas price. All costs to the state include the area above the MPR line since the IOUs are responsible for paying all costs below the MPR. The cost difference between the marginal cost of production (where renewable energy supply equals 100%) and the MPR is equal to the shadow price as explained in the previous section. Arrow A and B represent the shadow prices of scenario (1) and (2), respectively. The costs of renewable bids that fall above the MPR (dashed line) will be eligible for SEP funding.

Although Figure 4-5 shows the generator's costs, it does not predict the actual price of the generator's bid. This analysis assumes that generators will bid as low as their cost of production and as high as the marginal cost of renewable generation.

Figure 4-6: $Cost_{min}$ Based on Renewable Energy Supply for the RPS, 2010

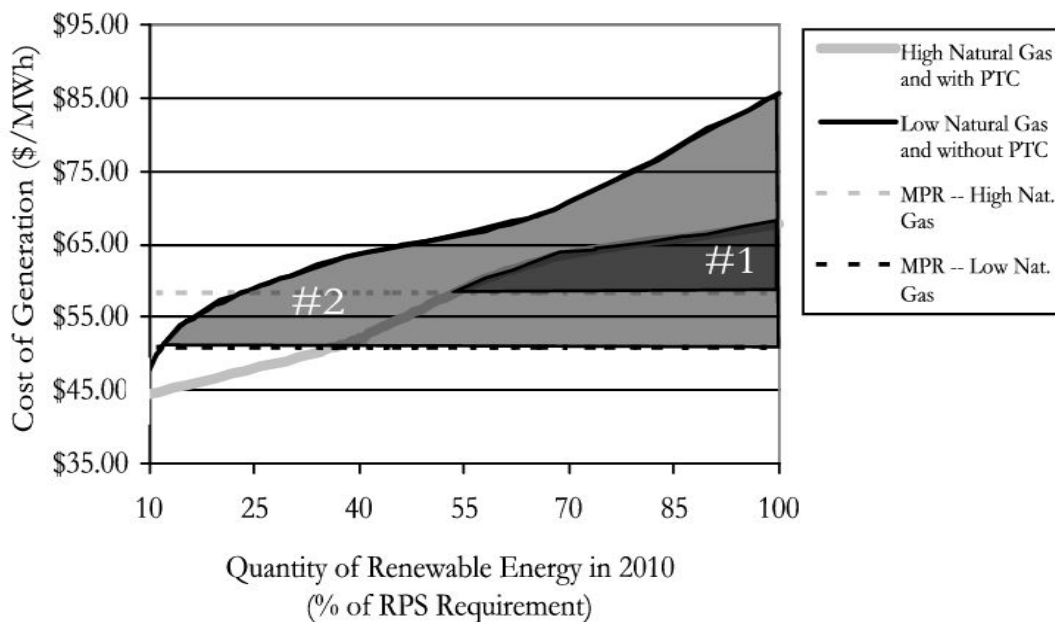
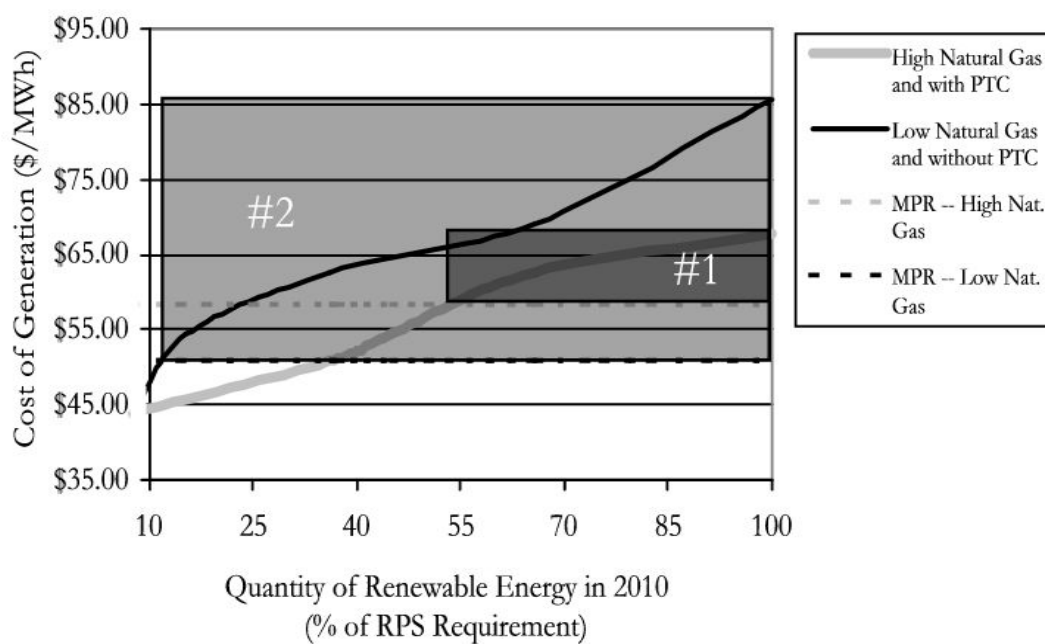


Figure 4-6 illustrates $cost_{min}$ based on the supply of renewable energy for the RPS in 2010. The shaded areas, Area #1 and Area #2, represent the $cost_{min}$ for scenarios (1) and (2), respectively. The areas are the minimum expected costs of the RPS program to the state for each respective scenario in 2010. These costs are only expected to occur if the competitive bidding process succeeds in driving all renewable generator bids down to their costs of production.

Figure 4-7: $Cost_{max}$ Based on Renewable Energy Supply for the RPS, 2010



Similarly, Figure 4-7 is an illustration of $cost_{max}$ based on the supply of renewable energy for the RPS in 2010. The shaded areas, Area #1 and Area #2, represent the $cost_{max}$ for scenarios (1) and (2), respectively. These are the expected costs to the state, for each respective scenario, if all generators bid at the marginal price of renewable production. This will occur if the bidding process fails to drive down bids. Again, the confidential bidding process limits the generators' knowledge regarding other submitted bids (and thus the marginal cost of production) and the applicable MPR, intending to increase the likelihood of marginal cost bids.

Figure 4-8: $Cost_{min}$ and $Cost_{max}$ based on Renewable Energy Supply for the RPS, 2010

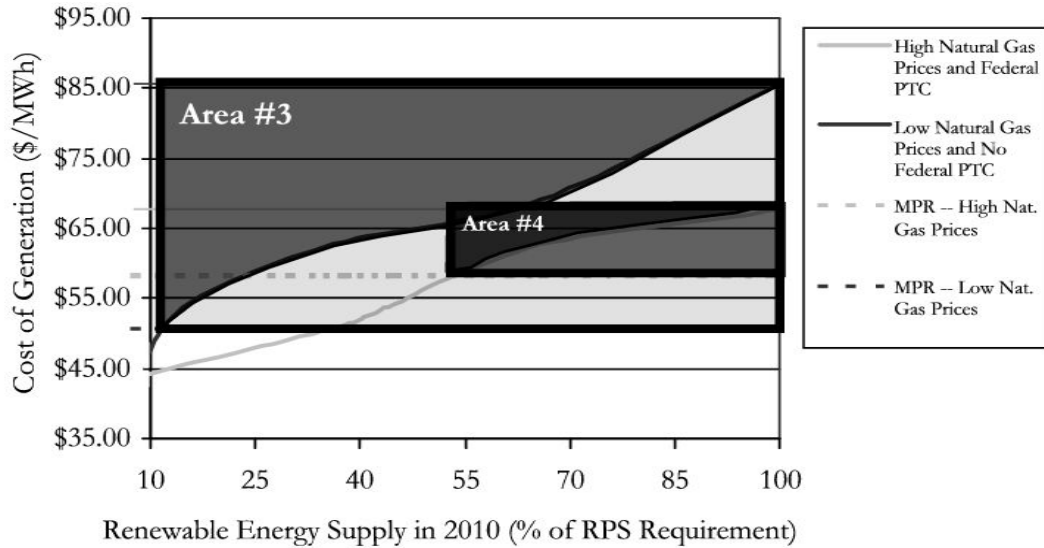


Figure 4-8 represents the relationship between $Cost_{min}$ and $Cost_{max}$. In Figure 4-7, Box #1 and Box #2 represent the total potential cost to the state ($Cost_{max}$) and in Figure 4-6, Area #1 and Area #2 represent the minimum potential cost to the state ($Cost_{min}$). In Figure 4-8, the area above the curve and within the box (Area #3 and Area #4) for each scenario represents the range of potential costs, as generators bids will most likely fall somewhere between their actual costs of production and the marginal cost of production.

Table E summarizes the findings of the model in 2003 dollars. For these results, it was assumed that the costs used to calculate the results would remain constant within each model run year (2005, 2010 and 2015). Recall that the model was designed to produce $cost_{min}$, while $cost_{max}$ was calculated based on the shadow price for each run multiplied by the renewable generation required by the RPS.

Table E: Summary of Model Results ($Cost_{min}$) and Inferred $Cost_{max}$								
			2005		2010		2015	
			$Cost_{min}$	$Cost_{max}$	$Cost_{min}$	$Cost_{max}$	$Cost_{min}$	$Cost_{max}$
Normal	High Natural Gas	With PTC	\$5,638,756	\$21,926,027	\$71,946,965	\$162,414,222	\$0	\$0
		Without PTC	\$32,722,094	\$123,013,572	\$133,860,538	\$401,329,761	\$0	\$0
	Low Natural Gas	With PTC	\$17,432,483	\$38,708,002	\$49,582,861	\$257,039,781	\$5,971,706	\$4,477,015
		Without PTC	\$46,954,845	\$139,795,547	\$222,147,655	\$495,955,320	\$48,693,317	\$55,543,169
Accelerated	High Natural Gas	With PTC	\$25,269,734	\$114,065,251	\$71,946,965	\$162,414,222	X	
		Without PTC	\$89,447,228	\$226,827,059	\$235,832,073	\$401,329,761		
	Low Natural Gas	With PTC	\$43,381,250	\$130,847,226	\$150,580,076	\$257,039,781		
		Without PTC	\$110,083,234	\$243,609,034	\$352,128,137	\$495,955,320		

4.1.4 Caveats

There are innumerable complications that impact the cost of electricity. Appendix E discusses some of the model’s limitations (e.g., transmission service charges, changes in demand, and price of fuels), but several factors that influence the model’s results significantly are mentioned here.

- *Market Price Referent* – As discussed already, the heights of the cost curves for each scenario are in part a function of the level of the MPR. The MPR that will be calculated by the CPUC may or may not be greater than the MPR generated by the model. However, this calculation does not incorporate unplanned downtime and other outages that are not reflected as the published capacity factors. In reality, the actual market price for electricity is potentially higher. If a more accurate market referent is used (which should be greater than the model’s MPR) then the overall cost to the state in this analysis would be overestimated.
- *Bidding Levels* – The results produced by the model represent the above-market costs of producing renewable energy (previously referred to as “ $cost_{min}$ ”). However, in reality it is possible that generators will bid above this level in an attempt to maximize profits, not just recoup costs. As a result, the actual costs to the fund could be greater than the $cost_{min}$ curves represented in the results graph Figure 4-1. The degree to which they are greater depends, among other

things, on the efficacy of the bidding process in keeping bids on par with costs and the liquidity of the market.

- *Compliance Flexibility* – The model does not incorporate flexible compliance mechanisms into its calculations, although to do so would present opportunities for spreading out the costs of the program over time and minimizing costs to the program by increasing market efficiency. Flexibility mechanisms include extending deferment of procurement deficits, loosening APT schedules, rolling over unspent funding, and introducing a TREC market.

4.2 Implications of Model Results for California

As described in the previous section, the RPS costs to the fund are expected to peak rather significantly in the middle of the program’s life. The size of the fund is expected to be sufficient at the beginning and end of the program but insufficient during the middle of the program. It would be advisable, therefore, to either “flatten” the curve to better match demand on the fund over time or to redistribute the funds to match the peaking pattern of the curve. Flexibility mechanisms such as extending deferment of procurement deficits, loosening APT schedules, rolling over unspent funding, and introducing a TREC market could present opportunities for optimizing available funds

- *Flexibility in the APT Schedule* – Increasing flexibility in the IOU’s APT schedules would allow the Energy Commission to shape the IOU’s required “ramp-up” schedule based on the anticipated demand on the fund. Such flexibility could “flatten” the cost curve such that the demand on the fund during peak years will be shifted to the earlier and later years of the program.
- *Banking* – Banking would have the impact of shifting the demand on the fund by paying for compliance that is done ahead of schedule. Banking should be encouraged at the beginning of the program when the cumulative costs have not yet built up to the point of depleting the fund. Banking should be discouraged, however, during years when the fund is expected to be strained (e.g. the middle third of the program). A strong-arm approach, although not necessarily recommended, would be to only allow banking during the early stages of the program.
- *Borrowing* – Borrowing has essentially the opposite effect of banking. With banking, excess compliance is applied to future years. However, with borrowing, there has been under-compliance, causing the IOU to “borrow” compliance from subsequent years, under the obligation of paying it back later. Borrowing could represent an advantage to the fund by shifting demand on the fund to a later period when the fund should not be as strained. As a result, borrowing should be encouraged during the peak of demand on the fund. Under the current structure of the RPS, utilities are permitted to incur a maximum APT deficit of 25%, to be met within three years. Again, a stronger regulatory

approach would be to *only* allow borrowing during the expected peak demand on the fund.

- *Fund Rollover* – Allowing the fund to roll over annually could also reduce the expected strain to the fund in future years. The amount of funds that could be captured from such a rollover is not certain, as it will be a function of the demand on the fund during the previous year.
- *TREC Market* – A TREC market would allow utilities to purchase credits from the least-cost renewable technologies to satisfy their APTs. Cost savings under a TREC market would potentially ease the strain on the fund throughout the life of the program.

The implications of the model’s results indicate the goals of the RPS would not be met during the middle of its life because the demand would exceed the supply of funding. The flexibility mechanisms mentioned above could have the effect of easing the strain of a concentrated demand on funding in certain years. While first four items are not focus of this study, and therefore not recommendations, they are options to be considered for managing the peak demand.

With an understanding of the model’s results and behavior, the discussion now turns to how these results compare to existing renewable energy markets. To do this, the following section addresses how shadow prices were generated from the model and how they compared to TREC data from three markets.

4.3 Comparison of Shadow Price and TREC Data

In calculating the total direct cost of the RPS, the model generates a shadow price for each scenario that represents the above-market marginal cost of renewable generation. In open and competitive markets, the price of a good generally equals the marginal cost of production of that good. Hence, the shadow prices produced by the model represent the price of a TREC in a hypothetical open TREC market.

In order to put the model into context, the shadow price results were compared to TREC prices in existing markets to determine the likeness of the results to existing markets. The Texas, Massachusetts, and PJM REC markets were selected for comparison because each state allows TREC trading for state RPS compliance and has been trading credits since at least last summer. See Appendix J for a further discussion of these markets and their applicability to California. Table F provides a summary of the average “last price” for the three TREC markets from July 2003 through January 2004 traded at an environmental brokerage. Last price represents the selling price for the last TREC transaction for each month. Because last

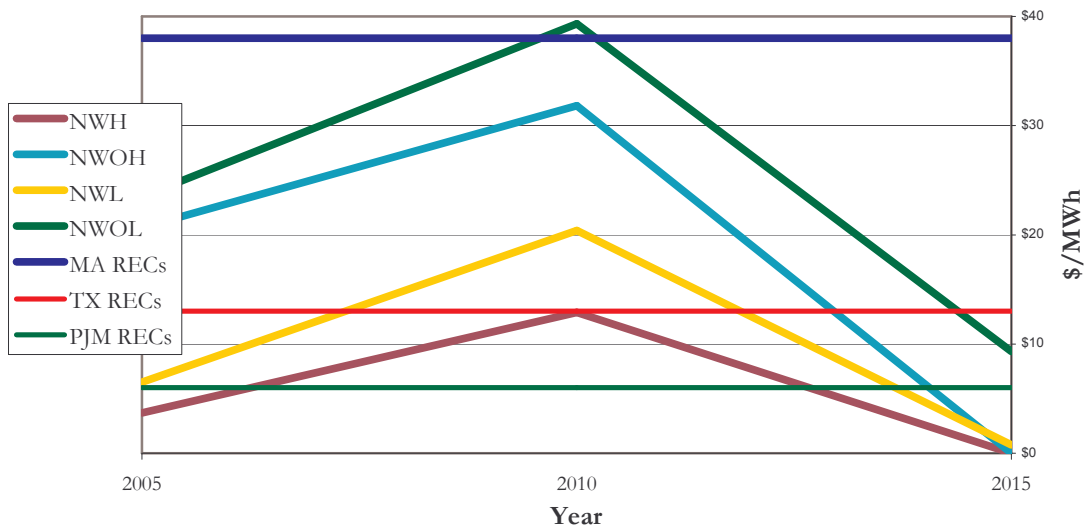
Table F: Average TREC Sale Prices, 2003	
Texas	\$13.10
Massachusetts	\$38.45
PJM Class I	\$5.92

Source: Evolution Markets LLC

prices are provided for several TREC vintages, this analysis averaged all of the last prices for all vintages in order to calculate a representative price for each TREC market over the seven-month period of available data. TREC vintages that were included in this average varied depending upon their activity within that market. For example, the Texas market includes 2002 and 2003 TREC vintages. The Massachusetts market includes 2003 and 2004 TREC vintages, while the PJM Class I market includes 2003 through 2006 TREC vintages. For additional market price data, refer to Appendix I.

The 2003 TREC prices listed in Table F were compared with the model’s shadow prices for four scenarios in 2005, 2010, and 2015 to determine whether the model’s results reflect observed market behavior. Figure 4-9 shows that, indeed, the model’s results fall within the range observed in existing TREC markets.

Figure 4-9: Normal RPS Shadow Prices and TREC Market Prices



The model’s variance of shadow prices is similar to the price variability between existing TREC markets. That is, the forecasted TREC prices as produced by the model fall within the same range of prices demonstrated in real TREC markets. The fact that the shadow prices generated from the model are comparable to existing market prices lends support to the results of the model as being comparable to real markets. Scenarios that were characterized without the PTC, for example, exhibited shadow prices similar to Massachusetts TREC prices, regardless of whether natural gas prices were high or low. The scenario characterized with the PTC and low-priced natural gas exhibited shadow prices similar to Texas TRECs. This may be attributed to Texas’ low natural gas prices and the fact that wind comprises most of the state’s renewable resources and therefore benefits the most from the PTC. The scenario characterized with the PTC and high-priced natural gas exhibited shadow prices similar to both Texas and PJM TREC prices.

4.4 TREC Assessment Results

Based on this study's assessment of available TREC policy and pricing data, it has been found that TRECs present an opportunity, with a well-constructed policy design, to lower compliance costs, facilitate market entry, increase the selection of renewable resource options, enhance compliance flexibility, and contribute to greater administrative flexibility. These benefits have important implications for California's RPS program, as they could better enable the program to meet its goals.

In summary, several of the more theoretical lessons learned from the literature include the following points.

- *Additional Market Participants* – It is expected that the creation of a tradable credit market will encourage more players to enter the new commodity market over time. New participants could include generators, aggregators, or other electric utilities.
- *Program Flexibility* – Increased flexibility offers utilities another method for complying with the RPS.
- *Removal of Additive Costs* – Tradable credits can eliminate temporal and spatial components from the utility's purchase transaction.
- *Development of Best Resources* – Decreasing spatial constraints could further encourage the development of the least-cost renewable resources. That is, without the delivery requirements, project development decisions could be more heavily based on energy potential than proximity to load demand.

Lessons drawn from real experience do not diverge much from the theory, but rather supplement the reasons listed above. While the reasons for adopting TRECs into a state RPS vary across states, there is substantial overlap and are reflected below. States have adopted TRECs:

- to hedge against a general concern for a short supply of renewable resources;
- to decrease compliance costs, and thus program expense;
- to simplify verification efforts;
- to provide incentives for further development of new renewable projects;
- to add compliance flexibility; and
- to value the renewable attributes as tradable commodities.

All of these reasons appear to be attractive incentives for California to adopt tradable RECs.

4.5 Implications for a California TREC Market

Because of the novelty of TREC markets, there is little data available upon which to quantitatively determine the future impacts of the California TREC market. However, similar markets such as Texas have demonstrated early success in their TREC programs and have provided insight into the future behavior of these markets. For example, one observed market behavior is that the majority of Texas TRECs are sold in the form of long-term contracts with their electricity, which is similar to a BREC transaction. Nevertheless, market participants within Texas have expressed a preference for TRECs due to their inherent flexibility to respond to price fluctuations [39].

In general, integrating TRECs into the California RPS would not be expected to alter the bidding process for renewable energy in the short-term. In fact, a TREC market in California could develop in the same manner as Texas, resulting in most of the TRECs being purchased through long-term contracts. As well, the Energy Commission anticipates that TRECs would continue to be bid with their electricity [20],[42]. However, the primary advantage of TRECs would be the increased liquidity of a California, potentially regional, TREC market.

4.5.1 California Market Area

The ideal size for the California TREC market depends upon the goals of the RPS. For example, some RPS programs are targeting issues of national or global concern such as climate change (e.g. Connecticut's RPS). Consequently, the goals of these programs can be met regardless of whether tradable RECs are purchased and traded locally or nationally. The California RPS, however, is designed to not only displace many of the environmental externalities associated with conventional generation, but also to provide economic benefits through the development of local and regional renewable resource markets. A national TREC market could not guarantee that the residents of California would enjoy the economic and local environmental benefits from renewable energy. Consequently, a national TREC market would not serve the purposes of the California RPS program as defined today.

In order to ensure that California ratepayers receive the anticipated benefits from renewable electricity, the Energy Commission may prefer to limit the size of a future California TREC market. Two options for the Energy Commission include either constraining a TREC market to a "super-market area" such as WECC, or limiting TRECs to a smaller market area such as the state of California. However, choosing between these two market sizes would have implications for the success of a future TREC market. First, the larger sized WECC market would serve to stabilize and reduce TREC prices over time through greater resource supply and more market participants. Such benefits from large TREC markets have already been observed in the NEPOOL market. For example, ERCOT has benefited from its access to a plentiful supply of wind energy, while states such as Massachusetts have opted to take advantage of a larger

market by allowing their RECs to be traded throughout NEPOOL, given eligibility requirements are met.

In contrast, a smaller TREC market size that is constrained to the state of California may better ensure that state ratepayers are the primary recipients of the benefits from renewable resources. However, as stated earlier in Section 3.3.1, the smaller size of a state market may also contribute to greater TREC price volatility. In addition, there are specific RPS regulations currently in place that permit certain out-of-state generators to be eligible for California RPS compliance (see Appendix B). Future regulations regarding the use of out-of-state generated TRECs cannot conflict with existing RPS eligibility requirements. Consequently, the Energy Commission would not be permitted to restrict a TREC market entirely within the state of California without making provisions for these out-of-state generators.

The Energy Commission may consider that, as a member of WECC, California would still enjoy the benefits from increasing its renewable resource supply from anywhere within the western grid. Therefore, the Energy Commission may choose to define TREC eligibility as generation that originates within, or is transferred to, the WECC, which is similar to the requirements for TREC eligibility within NEPOOL.

4.5.2 California TREC Property Rights

Defining the size of the California TREC market would also have implications for determining eligibility for SEP payments. As mentioned above, one of the goals of the California RPS is to ensure that ratepayers enjoy the benefits of the renewable energy that is supported by their surcharge revenue. In order to satisfy this goal, the Energy Commission may need to restrict ownership of TRECs from projects that receive SEPs. The Center for Resource Solution's *Regulator's Handbook on Tradable Renewable Certificates* recommends that the administrator of a state's PGC fund should "consider and make explicit whether and when it is appropriate to prohibit certain projects from having their [TRECs] used to comply with RPS mandates (in their state or other states) while simultaneously receiving [PGC] support....to ensure that renewable energy policies have the greatest positive impact" [43]. Consequently, the Regulator's Handbook suggests that if California TRECs are eligible for SEPs, then the Energy Commission must devise a method to prevent renewable projects that receive ratepayer funding from selling their TRECs out-of-state. Without such a restriction, California may be subsidizing the generation of TRECs that are eventually used for another state's compliance needs.

In order to regulate TREC property rights, the Energy Commission may choose to (1) restrict eligibility for SEPs, and (2) restrict TREC sales from generators who receive SEPs [32]. Under the first method, the Energy Commission has already determined that some out-of-state generators may be eligible for SEPs, provided that they are connected to WECC and have contracts with end use customers of California IOUs (see Appendix B). Therefore, in order to ensure that ratepayers' surcharges are not used to subsidize renewable generation outside of the California market area, the Energy Commission

should continue to require that out-of-state generators receiving SEPs use their funded generation to benefit California residents. Under the second method, the Energy Commission has the opportunity to limit the transfer of SEP-funded TRECs outside of California. For example, the Energy Commission could either require all TRECs originating from a subsidized project to remain in-state, as seen in Rhode Island, or it could place locational limits on a percentage of the total generated TRECs, as seen in Massachusetts (see Section 3.3.1). The Energy Commission could also choose to restrict the movement of TRECs while the generator is receiving SEPs, and then permit TRECs to trade outside of California once the SEPs expire.

4.5.3 TREC Banking

The CPUC has already determined that a form of compliance banking will be permitted under the California RPS (see Appendix B). Because the model has demonstrated that the fund will be overtaxed in some years and underutilized in others, the CPUC should also permit banking within a future TREC market. As explained in Section 4.2, banking would have the impact of shifting the demand on the fund by paying for compliance that is done ahead of schedule. Banking also serves to hedge against market fluctuations that are caused by inter-year variability and other market uncertainties. In general, flexible compliance measures such as banking that are implemented under a BREC market would also serve to enhance the liquidity of a TREC market.

5 RECOMMENDATIONS

Senate Bill 1078 created the California RPS with the intention of increasing the mix of renewable energy in the state's energy supply to realize the benefits of promoting stable electricity prices, protecting public health, improving environmental quality, stimulating sustainable economic development, creating new employment opportunities, and reducing reliance on imported fuels [6]. The law also introduced secondary goals such as promoting additional environmental stewardship beyond the increasing renewable generation and giving preference to projects that have tangible benefits to minority and low-income communities.

To realize these stated goals, the remaining RPS implementation rules must be carefully designed to foster the attainment of renewable procurement targets in the least costly way so that funds are not exhausted. However, as demonstrated by the model results, California's costs for meeting the RPS requirements could exceed available funding. Therefore, in order to ensure the success of the RPS program, the Energy Commission should identify a means to reduce the overall cost of the policy to the state.

5.1 Recommendations

Recommendation #1: SEP Eligibility for TRECs

We recommend that tradable credits that originate within California be eligible for RPS compliance. These credits should also be eligible for SEPs. That is, provided that the legal requirements for electricity delivery are met, as stipulated by the existing RPS language, generators should be eligible to receive ratepayer funds for their above market costs. Placing in-state delivery requirements on all funded generation projects ensures that California ratepayers receive the benefits of displacing conventional energy sources by greening the energy supply.

Recommendation #2: Out-of-State Eligibility

We recommend that credits originating outside of California be eligible for RPS compliance, provided three rules are met. First, the source of the credits must be compatible with the resource eligibility rules as prescribed by California's existing RPS. Second, no ratepayer funding may be used for TRECs generated outside of California (unless they meet delivery requirements currently stipulated by the law). Third, the electricity must be delivered to the western grid.

Establishing a TREC system that only allows generation from within the WECC could potentially come into question in regards to the Interstate Commerce Clause²⁴. However, there are several means to maintain the local benefits of renewable generation without raising any questions of constitutionality. Each places potential geographical boundaries on TREC generation as well as the import and export of attributes without actually prohibiting TREC transactions from out-of-state. Limiting RPS eligibility by technology, resource compatibility, and transmission requirements ensures the constitutionality of the requirement.

Recommendation #3: Banking TRECs

Banking of tradable credits should be allowed in order to displace the strain on the fund that is expected to occur during the middle years of the program, as explained earlier by the model results. Banking also serves to hedge against market fluctuations that are caused by inter-year variability and other market uncertainties.

5.2 Topics for Further Analysis

This analysis has concluded that TRECs have the potential to aid California in achieving its goal of 20% renewable electricity by the year 2017. The following describes areas of further research that could lead to more detailed and potentially more useful results.

The model created by this analysis provides a coarse simulation of the California electricity market. The utility of the model could be vastly improved by including a spatial analysis, including details on transmission pathways. Modeling the spatial dynamics of transmission infrastructure could lead to a better understanding of the cost difference for transmission service in a BREC versus a TREC regime. This would also permit each IOU and each renewable resource to be treated separately, allowing the model to predict the expected location of resource development given regional resource potential, technology development costs and regional transmission costs.

The TREC market analysis could be enhanced by examining the effect that competing markets might have on the demand for TRECs in California. Such competing markets include voluntary REC markets and future RPS mandates in other states that allow interstate procurement of TRECs for compliance.

Finally, it could be interesting to examine how future developments within the rules of the California RPS may affect the decision to allow TRECs. For example, it is expected that Electricity Service Providers, Community Choice Aggregators, and municipal

²⁴ Limiting the trade of TRECs for RPS compliance is governed by Interstate Commerce Clause (Article 1, Section 8 U.S. Constitution), which places all regulatory power of imports and exports between states and nations in the hands of Congress. Further discussion of the Interstate Commerce Clause and what states are doing to stay within the legal bounds of the law are included in Appendix K.

utilities will eventually be required to comply with the RPS. It is not immediately obvious whether these local entities should be allowed to participate in the WECC-wide (or statewide) trading program to achieve their RPS goals. Additionally, Senator Sher has proposed extending the accelerated RPS of 20% by 2010 to 33% by 2020 (SB 1478). A separate analysis would be required to determine the expected cost of augmenting the goals of the RPS.

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Appendix A: Glossary [43]

Annual procurement target: The quantity of eligible renewable resources that a retail seller must procure within a particular year as mandated by the RPS.

Attribute: Descriptive or performance characteristics of a particular generation resource. The characteristics of renewables and other generating types (both positive and negative) not reflected in the price of power are referred to as externalities and include environmental, economic, and social characteristics (also see Environmental Attribute).

Banking: Deposit of certificates for later application or trade.

Baseline: In this handbook, baseline refers to the quantity of eligible renewable resources that were procured prior to a RPS or other obligation taking effect. State or federal regulatory programs determine the parameters of what is included in a baseline calculation.

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

Borrowing: The use of a certificate that has not yet been generated, but for which there is a contract or intent to purchase, to meet a current obligation, e.g. using 2005 certificates to meet an obligation in 2004. Certificate borrowing usually occurs in conjunction with a regulatory program that has a multi-year compliance period.

Bundled REC (BREC): A bundled transaction is one where the renewable certificates and electricity are sold together.

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

Capacity Factor (“Availability”): A measure of the productivity of a generating facility, calculated by the amount of power that the facility produces over a set time period, divided by the amount of power that would have been produced if the facility had been running at full capacity during that same time interval. For the purpose of this study the capacity factor of existing facilities was based on comparing the existing capacity of a technology with its actual annual production. The capacity factor for new facilities was based on published values.

Conventional Energy Resource: A general term for any energy resource that is not an eligible renewable resource in the California RPS. This generally means power derived from nuclear energy, the operation of a hydropower facility greater than 30 megawatts or the combustion of fossil fuels, although cogeneration technologies provide some exceptions.

Cost_{max}: This is the greatest expected level of demand on program funds for a given year and given scenario. This value is based on the assumption that all renewable generators will bid at the marginal cost (i.e. the shadow price as produced by the model) of renewable energy that is forced by the RPS. The values presented do not include cost of transmission service.

Cost_{min}: This is the lowest expected level of demand on program funds for a given year and given scenario. This value is based on the assumption that all renewable generators will bid at the cost of generation of renewable energy that is forced by the RPS. The values presented do not include cost of transmission service.

Disaggregation: Separation of one or more attributes of the unbundled TREC to permit independent sale of such attributes.

Environmental Attributes: Environmental attributes include the environmental benefits and costs associated with the construction and operation of specific types of power generation facilities. For renewable facilities, their environmental attributes might include the benefits of such things as emissions avoidance or offsets, as say from wind-generated electricity. Several air pollutants (e.g. CO₂, NO_x, and SO_x) have separate markets today where the value of a pound of pollution is determined through sales and trade (also see Attribute).

Eligible Renewables: Sources of renewable electricity, such as solar electric, wind, geothermal, biomass and hydroelectric eligible to participate in a particular program.

Generation: Generation is the act of converting various forms of energy into electricity such as oil, gas, sunlight, or wind. Generation is the one part of the electric industry that has been opened to competition in some states.

Geothermal: Natural heat from within the earth, captured for production of electric power.

Investor Owned Utility (IOU, a.k.a. electrical corporations): For the purpose of the California RPS this refers to Pacific Gas and Electric Company, San Diego Gas and Electric Company, and Southern California Edison Company.

Kilowatt-Hour: A kilowatt-hour (kWh) is the standard unit of measure for electricity. One kilowatt-hour is equal to 1,000 watt-hours.

Least Cost, Best Fit: The decision process that the IOUs are required to use when selecting a renewable generation bid as designated by the CPUC. “Best fit” is designated as the renewable resources that best meet the IOU's energy, capacity, ancillary service, and local reliability needs.

Load: The time of day of electricity generation relative to the diurnal fluctuations in demand for electricity. This study has divided the loads into four categories: base, intermediate, daily peak, and seasonal peak.

Load Multiplier: Refers to a multiplier that calculates the amount of generating capacity that a non-base load needs to produce a given amount of electricity per day. The value is based on the fraction of the day that the load serves.

Market Price Referent (MPR): A price value that is intended to be representative of the market price of electricity. This price is calculated by a methodology to be published by the CPUC and will include separate values for baseload and peakload. The cost of the contract bids for renewable resources that are selected by the utilities to meet their RPS obligation will be compared to the market price referent. Costs for renewable products that exceed the referent, excluding indirect costs, will be covered by the SEP, subject to availability of program funds.

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

New England Power Pool (NEPOOL): Formed in 1971, the New England Power Pool is a voluntary association of entities engaged in the electric power business in New England. NEPOOL members include investor-owned utility systems, municipal and consumer-owned systems, joint marketing agencies, power marketers, load aggregators, generation owners and end users.

New Renewable Resource: A renewable resource that begins commercial operation on or after January 1, 2002 and meets the other eligibility requirements of SB 1038. The Committee has recommended that the date should be periodically updated as necessary.

Public Goods Charge (PGC): The California State policy that imposes a volumetric fee on ratepayers (on a per kWh basis) to support energy efficiency, renewable energy and public benefit programs through the Renewable Resource Trust Fund.

Production Tax Credit (PTC): The result of the Energy Policy Act of 1992, a tax credit that applies to wholesale electrical generators of wind energy facilities based upon the amount of energy generated in a year. As it exists today, the PTC for generators of wind energy is \$0.018 per kWh of electrical production for the first 10 years of wind power plant operation.

REC Banking: An administrative means by which RECs can be stored for later use or sale. For example, Texas RECs have a 3-year life. If a REC is not used in the year of its creation, it may be banked and used in either of the next 2 compliance periods (years). The issue date of the RECs coincides with the beginning of the compliance year in which the RECs were generated.

REC Retirement: Certificate retirement can be a voluntary or mandatory activity, usually the result of the, (1) delivery and consumption of a certificate to the end-use consumer; (2) application of the attribute value of a certificate the environmental impact of a consumer's use of electricity, or (3) the use of the certificate to comply with a statutory or regulatory requirement. Retirement of a certificate generally has the intent of removing the certificate from the market for subsequent sale, purchase, or use toward meeting a regulatory

requirement or voluntary application. Certificate retirement may have a very specific legal meaning in the context of a regulatory program.

Renewable Energy Certificate or Credit (REC): The term “REC” is generally synonymous with Green Tags and Transferable Renewable Energy Credits (TRECs). A REC is not electricity. It represents the renewable or “green” aspect of electric power generated through the use of renewable fuels, such as wind, hydro, solar, and biomass that produce one MWh or KWh of electricity from a certified renewable generator. Depending on the program under which they are generated, RECs can be bought and sold separate from the power from which they are derived. REC buyers include power generators and users that are required, or elect, to provide or use a certain percentage of green power. REC sellers include power generators and traders that hold more RECs than they require.

Renewable Energy Resource (Renewable Resource): A resource or fuel that produces energy derived from renewable energy technologies.

Renewable Energy Technology: A technology that exclusively relies on an energy source that is naturally regenerated over a short time and derived directly from the sun, indirectly from the sun, or from moving water or other natural movements and mechanisms of the environment. Renewable energy technologies include those that rely on energy derived directly from the sun, on wind, geothermal, hydroelectric, wave, or tidal energy, or on biomass or biomass-based waste products, including landfill gas. A renewable energy technology does not rely on energy resources derived from fossil fuels, or waste products from inorganic sources.

Renewable Portfolio Standard (RPS): A government policy that requires electricity retailers to purchase a specific percentage of sales from renewable energy generators.

Service Area or Service Territory: The geographical territory served by an electric service provider.

Time of Delivery Requirement: The requirement that an amount of electricity be delivered within a specified time period for use to meet load or other contractual agreements. TRECs are free from the time of delivery requirements needed to supply electricity.

Repower(ed): Refers to a facility that replaces 80% of the value of existing generating equipment with new capital investments.

Small Hydro: A facility employing one or more hydroelectric turbine generators, the sum capacity of which does not exceed 30 megawatts.

Supplemental Energy Payments (SEP): Incentive payments to eligible renewable generators for the costs above the MPR of energy procured to meet the RPS. Indirect costs, such as imbalance energy charges, sale of excess energy, decreased generation from existing resources, or transmission upgrades, are not eligible for SEP.

Tradable REC (TREC): A generic term for a bundle of attributes that does not include the actual electrical energy associated with the generation of electricity at a renewable energy facility. TREC can be awarded, traded, tracked, and submitted towards RPS compliance. Depending upon the facility, the TREC will embody various attributes with varying quantitative values. Values – such as avoided emissions – are quantified according to some baseline metric, engineering estimate, or a value deemed by private or government bodies. A renewable or green ‘tag’, green certificates, and tradable renewable certificate (TRC) are the equivalent of a TREC.

Transmission: The towers and high voltage lines that transport energy from power plants to the distribution company.

Unbundled: An unbundled transaction is one where the renewable certificates may be sold separately from the associated commodity electricity.

Utility: In a regulated electric market, the utility is the entity that owns and/or operates facilities for the generation, transmission, and/or distribution of electricity. In a restructured market, this entity becomes an electric distribution company responsible for transmission and distribution only, and provides default electrical service to consumers that elect not to switch to an ESP.

Appendix B: California's Renewables Portfolio Standard

Purpose of Statute

On September 12, 2002, California's Governor Gray Davis signed two complementary pieces of legislation into law to support the state's renewable energy development: Senate Bill (SB) 1078, which established the Renewables Portfolio Standard [6], and SB 1038 [8], which extended the existing Renewable Energy Program. A Committee Order, issued March 17, 2003, initiated a multi-phased RPS and established administrative procedures, a working schedule, and collaborative guidelines for the Energy Commission and the CPUC.

Building on previous legislation, SB 1038 establishes the framework for the Renewable Energy Program of which the RPS is a component. SB 1078 "requires retail sellers of electricity, such as investor owned utilities, to increase the renewable content of their energy deliveries by one percent per year...over a baseline level...[and] annual incremental procurement continues until renewable energy comprises 20% of the IOU's energy portfolio, a target that must be achieved by December 31, 2017." Recent discussion proposes an "Accelerated RPS" that would require the same percentage to be achieved by 2010.

As noted in the legislation, the purpose of the RPS is to: [6]

- Increase the diversity, reliability, public health, and environmental benefits of the energy mix;
- Increase California's reliance on renewable energy resources to promote stable electricity prices, protect public health, improve environmental quality, stimulate sustainable economic development, create new employment opportunities, and reduce reliance on imported fuels;
- Potentially ameliorate air quality problems throughout the state and improve public health by reducing the burning of fossil fuels and the associated environmental impacts; and
- Complement the Renewable Energy Program administered by the State Energy Resources Conservation and Development Commission.

Stakeholders

For the present time, the RPS requirements are limited to the three major California IOUs: Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E). Pursuant to SB 1078, each IOU must prepare a renewable energy procurement plan that will outline its long-term strategy to comply with the RPS. Since the IOUs serve 75% of California's electricity consumers [44], a large proportion of consumers will be directly or indirectly affected by the RPS as the utilities diversify their energy portfolios. At this time, publicly owned electric utilities are encouraged, but not yet mandated, to comply with the law, which states that these utilities are merely "responsible for implementing and enforcing a renewable portfolio standard that recognizes the intent of

the Legislature to encourage renewable resources” [6]. During Phase 3 of the implementation proceedings, consideration will be given to extending the RPS obligation to include Electricity Electric Service Providers (ESPs) and Community Choice Aggregators (CCAs).

Active public and corporate participation has been encouraged by the state throughout the implementation process. As written in the initial Committee Order, “Participation in this RPS Proceeding is encouraged and shall be open to all stakeholders and members of the public” [9]. The long list of those who have submitted briefs or testimony for consideration in the rulemaking process thus far illustrates the involvement and range of interested parties. For example, the Rate-setting Rulemaking procedure received feedback from numerous IOUs, non-governmental agencies, energy companies, energy associations, and other interested parties.

Funding

The Energy Commission was directed by SB 90 to distribute the Renewable Resources Trust Fund through five separate accounts: the Existing Renewable Resources Account, the New Renewable Resources Account, the Emerging Renewable Resources Account, the Customer-Credit Renewable Resource Purchases Account, and the Renewable Resources Consumer Education Account. The funding for the SEP comes from the New Renewables Resources Account (fund), which is funded through the public goods charge (PGC). The PGC is a product of the Renewable Energy Program and places a surcharge on all IOU electricity ratepayers. The PGC produces \$135 million annually, of which SB 1038 allocates 51.5% (or about \$70 million) to the fund.

The IOUs are only obligated to procure renewable energy at a level that can be covered by available funds [6]. Therefore, it is possible that the size of the fund will ultimately determine the level of renewable procurement by electrical corporations and consequently the level of state renewable procurement. The availability of SEP payments will be a function of demand and fund size. Whether the level of funding will be sufficient for meeting RPS obligations is not known at this time [45].

Governing Bodies

As established by the RPS legislation and Committee Order, the Energy Commission and the CPUC will work independently and collaboratively following explicit administrative guidelines to implement the RPS rules.

The Energy Commission’s responsibilities include:

- Certifying eligible renewable resources (including those generated out-of-state);
- Developing and implementing an accounting system to verify compliance; and
- Allocating and awarding supplemental energy payments to renewable generators to cover costs above the MPR for energy that is procured to meet the APTs.

The CPUC's responsibilities include:

- Establishing the methodology for determining the MPR, setting the criteria for least-cost best-fit ranking of renewable projects, and establishing flexible compliance rules, penalty mechanisms, and standard contract terms and conditions;
- Establishing the renewables portfolio baseline and determining the APTs for each IOU; and
- Factoring transmission and imbalance costs into the RPS process.

The *Committee Order on RPS Proceeding and CPUC Collaborative Guidelines* identifies and groups the implementation items into three phases, each with a respective deadline, and assigns each item to a specific agency. Phase 1 and Phase 2 were completed in 2003 and Phase 3 is expected to commence in 2004. Phase 1 addressed issues of defining eligible renewable resources, incremental geothermal, and the eligibility of out-of-state power. Phase 2 addressed decisions on distributing SEPs, certifying electricity generation facilities, and developing an RPS tracking accounting system. Phase 3 will address the creation of an accounting, tracking, and verification system; it will also examine the possible inclusion of TRECs into the RPS [46]. Each phase is discussed in further detail below.

The Energy Commission's Phase 1 & 2 Decisions

The Energy Commission finalized the following Phase 1 and 2 key decisions in June and August 2003, respectively [7]:

Eligible Renewable Resources

An eligible facility must use one of the following technologies: biomass, solar thermal, photovoltaic, wind, geothermal, fuel cells using renewable fuels, small hydroelectric generation of 30 megawatts or less, digester gas, municipal solid waste conversion using a non-combustion thermal process, landfill gas, ocean wave, ocean thermal, tidal current, and any additions or enhancements to a facility using that technology. This would include the repowering of older, less efficient facilities that meet repowering standards as defined by the RPS. In addition to facilities located within California, out-of-state facilities are eligible if located near the border with the first point of interconnection within the state, or if connected to the Western Electricity Coordinating Council (WECC) grid with guaranteed contracts to sell their electricity to a California IOU[8].

Baseline

The baseline for each IOU is the 2001 level of procurement of eligible renewable resources. IOUs will meet their RPS requirement by procuring renewable electricity above this baseline [47].

Supplemental Energy Payments

By law, IOUs are only required to pay generators the market price for the renewable electricity. The above market costs to the generator are paid with SEPs that are allocated by the Energy Commission.

Determining which facilities are potentially eligible for SEPs has proven to be a complex procedure. To this end, the Energy Commission has made a number of recommendations. First, the energy must come from a new or repowered source. In this case, “new” is defined as a resource that began commercial operation on or after January 1, 2002. “Repowered” is defined as a facility with new capital investments equal to at least 80% of the value of the repowered facility. Second, bilateral contracts between electrical corporations and renewable generators outside of a competitive solicitation are not eligible for SEPs. Finally, a single facility may receive more than one SEP award, provided that all of the generation is reported correctly to the accounting system for tracking purposes.

SEP award eligibility requires that the renewable contracts be a minimum of three years in length. The awards are paid for the lesser of 10 years or the duration of the contract with the electrical corporation. The SEPs will be terminated if projects fail to commence, to maintain operations, or to meet eligibility requirements. SB 1038 states that facilities may NOT receive SEPs if the electricity produced is [8]:

- Sold under an existing long-term contract with an existing in-state electrical corporation if the contract includes fixed energy or capacity payments;
- Used on-site or sold in a manner that is excluded from competitive transaction charge payments; or
- Produced by a facility owned by an electrical corporation or publicly owned utility.

A project that holds conditional funding under SB 90 may participate in an IOU solicitation for a power purchase agreement (PPA) but cannot receive SEPs in addition to the SB 90 award. To prevent double funding of a project, generators must declare any existing SB 90 awards and choose whether to relinquish them prior to execution of a new contract. If relinquished, the generator is eligible for SEPs like other bidders.

The Energy Commission may establish caps on SEPs; however, it may also waive those caps if a generator demonstrates that operation of the facility would provide substantial economic and environmental benefits to the end use customer. The Energy Commission may exhibit preference to projects that provide tangible benefits to communities with a multitude of minority or low-income populations [46].

It is expected that the Energy Commission will adopt a new guidebook in the first quarter of 2004 that will include guidelines for disbursing SEPs to renewable electricity generators for their above-market costs [48].

Certification Process

The Renewables Committee has recommended that “if a renewable energy resource sells energy to a retail seller to meet an RPS obligation, the renewable energy resource must be

certified by the Energy Commission as meeting the eligibility criteria” as defined by the RPS. Furthermore, projects that have been proposed, are under development, or are in construction, are eligible for provisional certification based on the owners’ self-certification of the project and subject to verification upon completion. A renewable energy resource that meets the definition of renewable for the purposes of the Renewable Energy Program or the Power Source Disclosure Program, but doesn’t meet the definition of an eligible renewable energy resource for the purposes of the RPS will continue to be “registered,” rather than “certified.”

Tracking and Verification System

The Committee has recommended that for 2003 and 2004 the Energy Commission use an interim contract-path accounting system to verify RPS compliance. It is expected that starting in 2005, an electronic-path accounting system will be operating in coordination with the Western Governors’ Association (WGA) that can record renewable generation and transactions. The tracking system should be capable of verifying compliance with the RPS by retail sellers, ensure that renewable energy output is counted only once, as well as verify retail product claims.

The CPUC’s Phase 1 & 2 Decisions

The following CPUC interim decisions are taken from *Order Initiating Implementation of the Senate Bill 1078{CPUC, 2001 #100}* and are a close approximation of what the CPUC will finalize as their Phase 1 and 2 decisions [49]:

Annual Procurement Target

The RPS law states:

“Beginning on January 1, 2003, each electrical corporation shall, pursuant to subdivision (a), increase its total procurement of eligible renewable energy resources by at least an additional 1% of retail sales per year so that 20% of its retail sales are procured from eligible renewable energy resources no later than December 31, 2017. An electrical corporation with 20% of retail sales procured from eligible renewable energy resources in any year shall not be required to increase its procurement of such resources in the following year” [6].

The CPUC has not deviated from this requirement. However, permissible levels of flexibility exist for meeting the APT, as described below.

Flexible Compliance and Penalty Mechanisms

The CPUC is charged with the task of creating flexible compliance rules for the RPS. A few examples of these flexible compliance mechanisms include allowing excess procurement in one year to be applied to subsequent years (“banking”) or allowing inadequate procurement

in one year to be achieved in following years [6]. The CPUC's interim decision is to permit IOUs to fall short of their APTs by 25%. This deficit will be permitted for a maximum of three years, by which time the IOU must be in compliance with all previous annual targets.

Although the 2017 deadline is absolute, with the exception of a first year exemption, annual shortfalls in excess of 25% of the APT will be permitted upon a demonstration of one of the following four conditions:

1. Insufficient responses to request for offers;
2. Contracts that have already been executed will provide future deliveries sufficient to satisfy current year deficits;
3. Inadequate PGC funds to cover the above-market renewable contract costs; or
4. Seller non-performance.

These flexibility mechanisms are adopted in order to allow the utilities to engage in good faith efforts to maximize ratepayer benefits and promote systematic renewable resource development. IOUs will incur penalties if they do not make a good faith effort to sign contracts with renewable generators in order to fulfill their RPS obligation. The penalty level as set by CPUC is currently \$50/MWh. The overall penalty cap is \$25 million annually per IOU.

Standard Contract Terms and Conditions

The CPUC must determine standard terms and conditions to be used by all electrical corporations in contracting for eligible renewable energy resources, including performance requirements for renewable generators. At this time the CPUC has not adopted a specific contract, although the type and level of detail that is required for fully developing standard terms and conditions is something that “falls better within the abilities of the parties to determine, rather than the” CPUC [9]. The CPUC will allow some bilateral contracts (contracts made outside of the competitive bidding process) only when such contracts do not require any PGC funds.

Market Price Referent

SEPs will be paid to contract-winning generators based on their above market costs of producing renewable electricity. These “above market costs” are relative to the MPR, which, in addition to being the maximum unit cost that an IOU is obligated to pay for renewable energy, is essentially the market price of electricity. When determining the methodology for setting the MPR, the CPUC must consider the long-term market price of electricity for fixed-price contracts, the long-term ownership, operating, and fixed-price fuel costs associated with fixed-price electricity from new generating facilities, as well as the value of different products including base load, peaking, and as-available output [6].

In examining the specified costs associated with a new generating facility, the CPUC expects to look at a hypothetical plant as a proxy. Based on general consensus by interested parties (see section on stakeholders below), the CPUC has recommended that the proxy for the benchmark price during the base load will be determined from a combined cycle natural gas

turbine plant. Similarly, a combustion turbine natural gas plant will be used as the proxy for establishing the benchmark price of peak load electricity.

Determining the MPR for as-available technologies (e.g., intermittent sources such as wind) is not necessarily analogous to determining the MPR for peak and base load technologies. As-available technologies may or may not operate at a particular time of day or year, and therefore, it is inappropriate to use a proxy plant for determining the value of as-available output. Until an alternative presents itself, the CPUC will use either the base load or peaking referent for the as-available proxy.

The CPUC expects to release a white paper on the methodology for setting the MPR in February 2004.

Least-Cost, Best-Fit

The least-cost, best-fit process is the method that the IOUs are required to use when selecting a renewable generation bid. Although least-cost and best-fit are separate concepts, the CPUC must consider the interrelationship between the two for the purposes of implementing the RPS program. While least-cost has a relatively standard criteria for all IOUs, best-fit is directly related to the needs of a particular IOU. Best-fit has been defined as the renewable resources that *best* meet the utility's energy, capacity, ancillary service, and local reliability needs. Although the renewable resources that are available may or may not be a perfect fit with the needs of the IOU, compliance with the procurement requirements of the statute will not be excused if an IOU claims that the available renewable resources are not an ideal match with its own projected needs.

In order to implement the least-cost, best-fit process, the CPUC expects to adopt an iterative ranking system (as recommended by SCE and PG&E). There are two steps in the process:

First Ranking

The purpose of the first ranking is to identify the bid price that will be compared with the MPR. Bids are ranked according to the product-specific MPR. The price referent reflects the value of two time-differentiated products: base load and peaking. Eventually, the CPUC will explore methods that more accurately reflect the value of energy and capacity on a time-differentiated basis.

Second Ranking

Bids will then be re-ordered based on integration and transmission costs. An Energy Commission Integration Study will be used to determine total integration costs for each short-listed contract. The study will reveal the integration impacts of present generation in specified areas. Intermittent resources utilize the Independent System Operator (ISO) Amendment 42 and internalize costs into bids; no further utility calculation of schedule deviations is needed, as discussed in the TURN/SDG&E Joint Principles [50]. Transmission costs will be assessed using the most appropriate process, depending primarily upon whether the project is in the ISO development queue.

The Energy Commission & The CPUC Phase 3 Issues

It is expected that Phase 3 issues will be addressed by June 2004. The issues to discuss include:

1. Determining the eligibility of renewable distributed generation (DG);
2. Ensuring resource diversity;
3. Commencing implementation of the RPS for ESPs and CCAs;
4. Developing criteria to determine competitive sufficiency; and
5. Finalizing plans for the RPS Tracking and Verification System.

Appendix C: California's Resource Base

Demand

The demand for electricity within the state of California varies from year to year (see Table C-1). After 2003, the demand within the state is assumed to increase by approximately 2.5% per year through 2017.

Table C-1: Demand for Electricity from California IOUs (2003 – 2017)		
Year	Total State Demand (GWh)	Total IOU Demand (GWh)
2003	244,139	151,523
2004	249,809	155,589
2005	255,549	159,776
2006	260,671	163,468
2007	264,276	165,943
2008	268,895	169,243
2009	272,165	171,410
2010	275,829	173,811
2011	279,551	176,265
2012	283,252	178,725
2013	286,139	180,399
2014	290,717	183,581
2015	295,368	186,818
2016	300,094	190,112
2017	304,894	193,465

Conventional Resource Discussion

Distribution of Conventional Resources

Geographically, the northern part of the state is dominated by hydroelectric generation and the southern part of the state is dominated by thermal generation, such as coal and natural gas. The distribution and source of electricity is an ongoing challenge for the state. For example, in the winter, thermoelectric power is transferred to the north when hydroelectric production is low, and in the summer, abundant and cheap hydroelectric power is transferred to the south when there is an increased demand. This transfer of electricity is often quite expensive as congestion along transmission lines constrains delivery.

Retirement Forecasts

The Energy Commission estimates that 25% to 50% of the state's thermal generators are more than thirty years old [51]. Assuming that the average lifetime is approximately thirty years for a typical natural gas power plant and forty years for a typical coal power plant, it is assumed that within the timeframe of the California RPS, a number of plants will be retired. At least in the short-term, the Energy Commission does not believe that retirement rates will be substantial. In fact, retirement rates through 2006 should be on the order of two to four percent of the IOU's capacity (see Table C-2).

On a longer time scale, estimating the retirement rate for existing plants is difficult. The decision of when to retire a plant is based on the profitability of the individual plant. The increasing age of a plant impacts maintenance and environmental control costs along with reliability concerns of the plant [52]. The information needed to assess each individual power plant is proprietary, confidential, or unknown [52]. Therefore, it is challenging to estimate the retirement rate beyond using power plants that have already been chosen for retirement. Forecasting retirement rates is further complicated by the fact that the decision of when to retire a plant also depends on the future costs of fuel and the price of electricity. If the price of electricity decreases in the future, many of the older plants still in operation will be too expensive to operate and will be forced to shut down [10].

Year	Expected Retirement (MW)	Percent of System Capacity
2004	1,191 MW	2%
2005	1,054 MW	2%
2006	2,385 MW	4%

Source: Aging Natural Gas Plants in California, Energy Commission

Based on the average retirements for the next three years, this analysis assumes that the rate of retirement for all technologies will be 2.5% of the system's total capacity per year.

Natural Gas Market

The market for natural gas power is inherently subject to fluctuations in the fuel price. Because of its prominence in the California electricity market, this price fluctuation can have wide ranging impacts on the entire market. The California Energy Crisis of 2000 highlighted the dependence of the market on natural gas and hydroelectric generation. In 2000, when the supply of natural gas dropped and a drought in the northwest caused hydroelectric generation to dwindle, the price of electricity skyrocketed within the state and caused widespread blackouts [53]. In response to this crisis, the Energy Commission commissioned a number of new power plants to be constructed, the majority of which were natural gas-fired plants, which served to further the state's dependence on this resource. The state's RPS is expected to alleviate some of this dependence by diversifying the California electricity portfolio.

The fuel price of natural gas directly impacts the RPS' cost to the state because the MPR is based on the market price of natural gas. If gas prices are low, the MPR will be set low and eligible facilities will receive large SEP payments. Under this scenario, the state would more readily exhaust the fund's resources, risking failure of meeting RPS requirements. Conversely, if gas prices are high, the MPR will be set high and facilities will receive relatively

small SEP payments [2]. The RPS goal, therefore, will be more easily met if gas prices continue to climb.

Renewable Resource Discussion

Repowering of Renewable Facilities

The act of “repowering” a generation plant involves the replacement of an existing facility with newer, upgraded technology. The repowering of aging renewable capacity, specifically old and less efficient wind turbines, is an important consideration under the RPS because wind farms already occupy many prime wind locations and utilize technology developed in the 1980s. Wind and other renewable technologies have improved to such an extent that it is sometimes more cost effective to replace the old turbines with newer, higher capacity, and more efficient turbines. Repowering a facility essentially upgrades the technology and increases the overall efficiency of the generation at a particular site. Currently, the decision to repower an existing facility is based on a number of the following legislative uncertainties:

- Whether the federal PTC will be extended to cover repowered facilities. As of now, the PTC only covers new wind projects [2].
- Whether the repowered facilities meet the requirements to be eligible for SEPs. Currently, only projects that reinvest at least 80% of the value of the repowered facility are eligible [2].
- Whether the acquisition of new air quality permits will be an impediment to repowering. The act of repowering will most likely force facilities to “re-open” their air quality permits and obtain new permits. This will only affect facilities such as biomass and landfill gas, since most other renewable sources do not release air emissions [2].

Repowering existing facilities will be an important factor in meeting the goals of the RPS. However, few estimates exist that delineate which facilities will likely repower and by how much. Such estimates would affect baseline figures. The Energy Commission estimates that as much as 450 to 900 MW of existing renewable capacity are candidates for repowering (see Table C-3), primarily from existing geothermal and wind capacity [2]. Further repowering efforts might be encouraged if repowered facilities are eligible for SEP payments [2].

Table C-3: Repowering Potential of Renewable Generation		
Technology	Potential for Repowering	Notes:
Wind	450 MW	Potential if the restriction on repowered facilities is removed from the Federal tax code and repowered facilities become eligible for the Federal PTC.
Biomass	0 MW	RPS provides no incentive to repower existing biomass facilities. With appropriate incentives, however, the efficiency of biomass technologies could be improved by 10%-30%.
Geothermal	Several hundred MW	Potential for repowering is mainly at The Geysers geothermal facility. Other geothermal capacity within the state has been built within the last ten years.
Concentrating Solar Power	0 MW	Even with incentives in place, the potential for repowering is minimal.
Landfill Gas	~100 MW	Because landfill gas is cost competitive, there is an incentive to repower. If SEP payments make it easy to do so, the potential to repower is high.

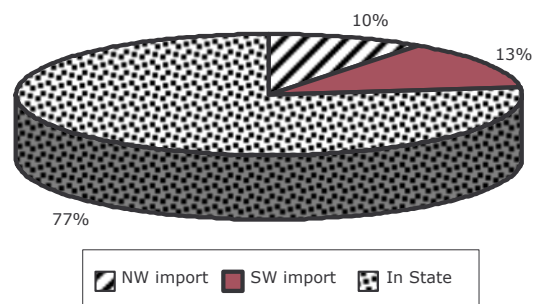
Imports

Electricity imports from the Northwest and Southwest regions of the United States have provided California ratepayers with up to 25% of their electricity at any given time [2]. With the reality of future peak and baseload demand increases, as well as the increasing pressure on utilities to provide renewable generated electricity to their ratepayers, it is likely that imports will play a significant role in RPS implementation.

Imports are wheeled into California through channels that already exist within the WECC grid. Three major interstate connections supply California with electricity from outside the state. From the southwest, Path 46 commonly called ‘West of Colorado River’ (WOR), imports power from southern Nevada and Arizona into San Diego and Los Angeles. Path 45, operated by the Comición Federal de Electricidad, imports power from Mexico to San Diego and the Imperial Valley. Path 66 is the California/Oregon line that connects the Malin Substation in Oregon to the Round Mountain substation in California, serving as the main line for imports from the northwest into California [54].

Technical potential data for WECC states suggest that California could import much of its required electricity for the RPS. However, current imports consist only of conventional electricity

Figure C-1
Imported Generation to California



[55]. In 2002, California imported 23% of its electricity from conventional sources located out-of-state. Ten percent originated from the northwest through the Malin substation in Oregon and 13% originated from the southwest and from Mexico (see Figure C-1) [56]. Because California imports such a large amount of electricity, imports have the potential to play a significant role in the RPS.

As previously stated, imports are not currently generated from renewable sources. The Phase II decision of the RPS implementation stated the eligibility rules for out-of-state renewable generators (see Appendix B). In effect, this decision opens the door for out-of-state projects to sell renewable energy to California's IOUs for RPS compliance. Costs associated with out-of-state RPS imports will likely be associated with transmission additions and accounting system verification. While imports are potentially eligible under the RPS, the Energy Commission has stated that it will prioritize in-state development since data indicate that California has abundant renewable potential within the state [2].

Transmission Issues

There is only one pathway through which electricity is transmitted between northern and southern California. From the north, it flows south along Path 15 between Los Banos and Midway, and then is transmitted along Path 26 between Midway and Vincent. Historically, this pathway has been a congestion point primarily during the summer when the capacity along these transmission lines is not sufficient to meet the supply shift from one part of the state to the other. Of the two sections, Path 15 is generally considered the major impediment to solving the state's congestion issues, especially when wheeling electricity from the south to the north. A large amount of electricity from Diablo Canyon and the San Joaquin Valley enters the transmission system at the northernmost point of Path 26 and subsequently can overload Path 15 to the north [54]. Currently, congestion is an issue along these lines, but with planned upgrades the system should be able to incorporate the increased transmission predicted for the future.

Seasonal transfers of thermal electricity from the south to the north along Path 15 have historically represented the biggest portion of congestion, rather than the transfers of hydroelectric generated electricity from the north to south [54]. A major transmission upgrade is currently underway that will add an additional 500 kV transmission line to the system [54]. This upgrade, scheduled to be completed in early 2005, is expected to alleviate current as well as future congestion along this route.

In the past, the congestion on Path 26 has not been an issue in either direction. Recently, however, the electricity being transferred from the north to the south has begun to overload the system and limits Southern California's access to relatively inexpensive hydroelectric generation [54]. With the exception of San Diego, there is an adequate supply of electricity in Southern California; thus, shortages are generally not an issue. Therefore, upgrading Path 26 is not as critical as upgrading Path 15. Nonetheless, Path 26 was recently upgraded and a second long-term upgrade is being planned. In mid-2003, a short-term upgrade was completed that increased the north to south capacity from 3,000 MW to 3,400 MW, effectively decreasing congestion by 31-50%. A second, long-term upgrade that will further increase capacity to 4,000 MW and decrease congestion to 77% of historic levels is in the

early planning stages and is expected to gain in priority once the Path 15 upgrade is complete [54].

In terms of RPS compliance, congestion along these pathways has the potential to limit SDG&E's ability to meet its RPS requirements in a cost effective manner. SDG&E currently has the lowest renewable electricity baseline, and therefore, will have the highest potential costs of coming into compliance. If the cheapest in-state renewable generation for SDG&E lies north of Path 15 and Path 26, this IOU, and ultimately the state, will be forced to bear the burden of the extra costs of transmitting through the potential congestion points.

Appendix D: Environmental Markets and TRECs

Environmental Economic Basics

Policymakers are generally interested in the current market equilibrium -- the point at which market price equals demand -- and whether this equilibrium results in the maximum welfare to society as a whole. It could be argued that the California electricity market is inefficient because the cost to society exceeds the private cost to electricity producers. This social cost indicates the presence of negative externalities that may include air pollution from fossil fuel combustion, price volatility, and dependence on foreign oil sources. A public policy such as the RPS could potentially internalize some of the externalities produced by the power industry and thus increase market efficiency. Reducing air pollution by switching to low or zero CO₂ emissions technologies, diversifying the energy portfolio to stabilize electricity prices, and reducing the state's dependence on foreign oil could alleviate some of these social costs.

California is just one of a handful of states to respond to electricity market externalities through a RPS [12]. Since electricity produced from renewable technologies often has a higher unit price than that of fossil fuel, the RPS mandate is expected to shift the unit cost of renewable procurement for utilities. While this specific cost should be offset by state SEPs, there are indirect costs associated with the purchase of renewable energy. These include transmission, remarketing and integration costs. It is very possible that these indirect costs will differ among the three IOUs, inducing the need for trade.

The development of the renewable energy market in the state of California will inevitably be shaped by the compliance mechanisms implemented by the Energy Commission. These mechanisms will also impact the marginal costs of renewable energy to each IOU. A bundled electricity requirement will force IOUs to procure and transmit renewable energy to their own region, introducing new relative cost differences among IOUs. For example, if the most abundant source of renewable energy for SDG&E is solar power while the most abundant for PG&E is wind power, but the cost of solar energy production exceeds the cost facing PG&E for wind energy production, SDG&E is faced with an inherently greater cost in meeting the RPS target than PG&E. Therefore, this command-and-control approach does not appear to cost-effectively implement the RPS because the marginal cost for each utility would not be equal.

Because the cost of achieving the RPS targets will be determined by the market price of renewable generation within the entire state of California, a tradable permitting scheme might be a more cost-effective means of implementing the RPS.

Sulfur Dioxide Trading Example

While a tradable permit system has the benefit of cost-effectively meeting targets and increasing technological innovation, it also has potential drawbacks. Lessons can be learned from examples of emissions trading precedents, one of the earliest being the sulfur dioxide market.

Title IV of the 1990 Clean Air Act Amendments (CAA) was the first implementation of a fully tradable emission-permitting scheme for sulfur dioxide [57]. Previous CAA Amendments in 1979 established a ‘bubble policy’ and an ‘emission offset policy’ to incorporate transferable emission credits for a given region. These policies allowed new and existing firms to increase their emissions as long as another firm in the same region reduced its current emissions by the same amount [58]. More than two decades later, Title IV established two phases of emissions reductions targets for coal-fired electric utilities. Phase I required annual emissions reductions targets for the largest and dirtiest facilities; Phase II involved further reduction of sulfur dioxide emissions for all generators by placing a cap on total annual emissions in the United States [57].

This cap was implemented with the annual issuance of emission allowances that permit a generator to emit a specified amount of sulfur dioxide per time period. In order to track these allowances, a generator is required to utilize monitoring equipment to report its total annual emission levels to the U.S. Environmental Protection Agency (EPA). At the end of each year, the generator must have enough allowances saved in an EPA account to cover its reported emission levels. Even though each allowance has a ‘vintage’ that specifies the year it is to be used, allowances can be banked for future use but not applied to any year preceding the vintage year recorded on the allowance [57].

The initial allocation of sulfur dioxide allowances was based on the historic emission rates of utilities. However, subsequent allowances have been allocated through annual auctions in which the EPA may sell two to three vintages per year. While the EPA has estimated that implementing this tradable allowance program in place of a command-and-control policy has saved utilities and consumers between \$700,000 and \$1 billion per year [58], there are two primary concerns regarding the potential social impacts of the sulfur dioxide market. First, the market may not be entirely efficient due to a lack of competition, attributable to the complex design of the trading rules. Second, unrestricted trading may contribute to the formation of ‘hot spots’ in which greater emission levels are concentrated in certain regions of the country. Consequently, with the implementation of a tradable allowances program, policy makers must consider the trade-offs between cost-savings and the local distribution of social impacts.

Appendix E: Model Methodology, Assumptions, and Limitations

Cost Methodology

The following is a discussion of the origin of each of the costs used in the model.

Capital and O&M Costs

Most data for capital and operation and maintenance (O&M) costs were taken from the Energy Commission's *Comparative Costs of California Central Station Electricity Generation Technologies* [59]. O&M costs were based on "variable costs" (\$/kWh), and levelized capital costs²⁵ were based on "fixed costs". Data from EIA's *Annual Energy Outlook Report 2003* were used for technologies that were not listed in the aforementioned report [60]. Because the EIA's overnight capital cost data were not pre-levelized, the model subjected those costs to a fixed charge rate (FCR) of 17%. This FCR was calculated by equating a given technology's overnight cost data to its fixed cost data [60].

Table E-1 contains the high and low natural gas price forecasts used in the model.

The cost of imported electricity was set equal to the MPR. The methodology for calculating the MPR is described further below. For both base and intermediate load imported electricity, the cost of imports was set equal to the level of the MPR that was anticipated for base load. The price of daily peak and seasonal peak imports was set equal to the level of the MPR that was anticipated for peak load.

Table E-1: Forecasts of Natural Gas Prices

	CEC	EIA
	\$/1000 ft ³	\$/1000 ft ³
2001	N/A	\$5.40
2002	\$4.55	\$3.85
2003	4.55*	\$5.73
2004	\$4.10	\$4.59
2005	\$3.94	\$4.26
2006	\$4.11	\$4.18
2007	\$4.29	\$4.22
2008	\$4.50	\$4.31
2009	\$4.72	\$4.19
2010	\$4.97	\$4.12
2011	\$5.25	\$4.27
2012	\$5.54	\$4.45
2013	\$5.83	\$4.63
2014	\$6.16	\$4.73
2015	\$6.50	\$4.87

* Assumed present day price of natural gas

Transmission Costs

In the model, transmission costs were limited to the developer's direct costs of connecting new projects to the existing grid. In other words, transmission costs refer only to the costs of building transmission lines and substations. The costs of transmission service and upgrades to the existing grid were not within the scope of this analysis. Part of the difficulty in predicting the future transmission service cost is due to the uncertainty of transmission congestion. It has been found that the probability of congestion does not exhibit a pattern for specific transmission links, because as loads change in the future, the power flow also changes both in magnitude and in direction [60]. Complicating the matter further, transmission service costs are site specific and are difficult to generalize for each technology.

²⁵ This capital cost data has been levelized by Navigant Consulting, a subcontractor to Xenergy Inc. In the case that such levelized cost data were not available a general fixed charge rate (FCR) was applied to the overnight costs of the technology in question.

The direct cost of connecting to the grid was estimated from data on historical power plant construction costs. Average transmission infrastructure costs were calculated on a dollar per MW mile (\$/MW mile) and were based on: (1) the total connection costs of each project divided by the distance of each power plant from the grid, and (2) the capacity of each project. Included in the cost of the transmission lines was a 20% markup to account for the cost of building substations. This data was only available for geothermal, combined-cycle natural gas, and simple-cycle natural gas plants, but the results were also used as the transmission costs for wind. The average distance of each technology from existing power lines was calculated from available data for combined cycle, single cycle, and geothermal projects [27]. The distance for the remaining technologies, excluding wind, was estimated from conversations with experts in the field.²⁶ Many of the remaining technologies, such as PV solar, landfill gas, and digester gas, were assumed to have negligible connection costs because they can be constructed within close proximity to the grid.

Table E-1 shows the calculated average distances of new projects from existing power lines.

Table E-1: Average Distance of New Generation Projects from Existing Power Lines

Technology	Average distance from grid (miles)
Combined Cycle	4.22
Single Cycle	0.06
Wind	8.28
Geothermal	26.00

The direct costs of connecting to the grid were expected to be greatest for wind projects based on the inherent remote location of wind potential. The average weighted distance of 8.28 miles from existing power lines was calculated based on data of wind potential [2]. The data was divided into “buffer zones” of wind quality. The average distance of each buffer zone to existing transmission lines was estimated from a map. The relative quantities of each wind type (Class 5 vs. Class 6 wind) were used to weigh the average distance of all wind projects from existing power lines.

The average transmission costs in the model do not capture the “first in” dynamic in which the first developer in a remote site must pay the initial, upfront cost of connecting the project to the grid. This omission was significant since this dynamic has, and will continue to be, an impediment to the development of certain areas with high wind potential.

A number of transmission costs were not included in this analysis. Among them were the costs to the IOUs for upgrading the existing grid due to unprecedented demand on certain paths resulting from increased renewable generation [61]. Although the model’s calculation of transmission capital costs is fairly crude, conversations with PIER revealed that the failure to fully capture the costs of transmission for renewable projects may be significant [28]. For example, natural gas plants are not required to pay for upgrades to existing lines incurred as a result of their project; instead, the cost is passed on to ratepayers. However, intermittent energy source developers, such as wind, are sometimes required to pay for the upgrades themselves. The justification for this inequity is that renewable energy sources are more unreliable than conventional sources.

Transmission Losses

²⁶ Personal communication with Christopher Namovicz, January 15, 2004.

The model matches the demand for electricity with the cost of production; therefore, it was necessary to account for the transmission losses that occur between the point of production and the end uses. Transmission loss data for specific technologies were taken from the aforementioned *Comparative Costs of California Central Station Electricity Generation Technologies* [59].

MPR Methodology

Since the CPUC had not published its intended methodology for calculating the MPR at the time of the analysis, the level of the MPR was based on the model output.

Base-Load MPR

The base-load MPR was based on the actual costs of a new combined-cycle natural gas plant while operating during base load.

$$MPR\left(\$/MWh\right)=\left[\frac{Total_Cost_of_New_Combined_Cycle_(\$)}{Total_Production_of_New_Combined_Cycle_ (MWh)}\right]$$

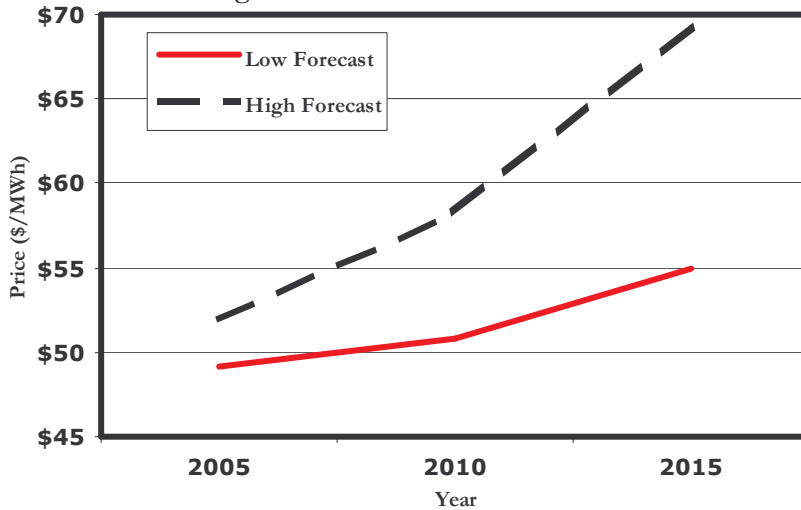
Peak-load MPR

The peak-load MPR was based on the actual costs of a new single-cycle natural gas plant while operating during daily and seasonal peak loads.

$$MPR\left(\$/MWh\right)=\left[\frac{Total_Cost_of_New_Single_Cycle_(\$)}{Total_Production_of_New_Single_Cycle_ (MWh)}\right]$$

The MPR levels that were calculated from the model are summarized in Figure E-1. The model estimated two MPR levels for each year, which were based on high and low natural gas price forecasts.

Figure E-1
High and Low Forecasted Level of the Base



Assumptions

Market Assumptions

The design of the model rests on a number of assumptions regarding the California electricity market.

1. No Market Powers Exist

The analysis assumes that the California electricity market is not influenced by market powers. According to Dan Adler of the CPUC, the market will be a “free-for-all” with little or no market power, based on the number of proposed projects in response to the RPS’s first round of RFPs for renewable projects. The California renewable electricity market is well developed in part because California has one of the oldest renewable markets in the world [49]. However, it is conceivable that a market power could develop via massive wind land acquisition.

2. No External Market Forces

This assumption states that no external markets will develop a demand for California renewable electricity that will significantly affect the price of renewable electricity.

3. IOU Compliance

It was inferred that demand for renewable electricity will match California’s RPS’ required ramp-up, based on the assumption that the major IOUs will comply with the RPS mandate.

4. Lack of Perfect Knowledge

The assumption of “perfect knowledge” of the marginal cost of a “good” is commonly made. Such an assumption explains the existence of a market price, which is set by the marginal cost of production. In this case, such an assumption is in fact contrary to the design of the bidding process for renewable contracts with IOUs. The confidential bids and unannounced level of the MPR is intended to encourage renewable sellers to bid their services at or near their cost of production. The goal is to avoid creating a market price where certain producers are able to profit at the expense of the fund. As a result, it was assumed that the generators will make bids that are at or near their costs of production, based on their *lack* of perfect knowledge.

Model Assumptions

Due to incomplete information or limited resources, the following assumptions were made in the model:

1. Near-Term Capacity Expansion Limits

In the short-term scenario (2005), the model assumes that capacity for both conventional and renewable projects will be limited to half of the capacity of the projects that responded to the Energy Commission’s first round of RFPs.

2. Long-Term Conventional Potential

The capacity limits for conventional projects for the long-term scenarios (2010 and 2015) were based on data taken from the Energy Commission’s “Energy Facility Status” website [27]. Combined-cycle natural gas plants were allotted very large potential (effectively limitless) since this is currently the technology of choice both from a market and political perspective. The expectation of combined-cycle plants to dominate the conventional electricity market is supported by projections from the WECC [19]. Coal and nuclear projects were not given any future potential based on a lack of RFPs issued by the Energy Commission, public safety concerns (specifically nuclear), and air quality laws (specifically coal). Large hydroelectric projects were also not given any future potential based on environmental concerns and the exhaustion of potential sites. Imported electricity was limited based on historic imports (per load) rather than based on a capacity limit.

3. Long-Term Renewable Sources

The capacity limits for renewable projects for the long term scenarios (2010 and 2015) were based on the total technical potential for those renewable technologies in California as found in the Energy Commission’s *Renewable Resources Development Report* [2].

4. Length of Renewable Contracts

An integral assumption to the calculation of expected direct costs to the fund is the length of time that renewable generators will continue to claim SEPs. Eligible generators are allowed to claim SEPs from between three years (the minimum allowable contract) and ten years (the maximum allowable duration of payments). The analysis assumes that the average length of contracts will be eight years based on generator’s motivation to be eligible for SEPs and the IOU’s motivation to remain compliant with the RPS. This assumption indicates that for any given year, the claims on the fund constitute all of the new renewable contracts for that year in addition to the claims made by all of the contracts for the previous eight years. This

assumption will result in a continuous accumulation of claims on the fund for the first eight years of the RPS. Therefore, the model dictates that after nine years, the contracts that were signed during the first year of the RPS are no longer eligible for SEPs.

5. Hydroelectric Generation Limits

Rather than limit hydroelectric production by capacity, the generation of electricity (GWh) was limited based on historical production data from 1983 to 2001 [62].

6. Load Factor

The “load factor” was based on results from integrating the Load Duration Curve (LDC) for the year of Aug. 2001 to July 2002 (see Appendix H). Although the load factor “multiplier” was chosen arbitrarily, the shape of each load determines the subsequent generation requirement. Essentially, the size of each load is not as important as the shape of the load duration curve [30]. The loads were separated into four since a fewer number of loads would not have adequately captured the capacity required by the seasonal peak, and a greater number of loads would have produced false precision.

7. Grouping Average Costs of Electricity Generation

Some technologies have been grouped and were assumed to have the same capital/O&M costs:

- All solar technologies, in addition to their costs, have been grouped into either solar sterling/thermal or photovoltaic technologies;
- Total wind potential in the *Renewable Resources Development Report* [2] was not divided into classes. Therefore, all wind potential was grouped into Class 6 (30%) and Class 5 (70%) based on visual approximation of each resource. Class 6 wind was assigned a capacity factor of 31% while Class 5 wind was assigned a capacity factor of 25% based on an approximation of commonly assigned values;
- Natural gas fuel cell costs were taken from cost data for fuel cell molten carbonate, as this was the least expensive capital cost for fuel cell technologies for which data were available. This has not affected the model outcome since fuel cell technology was more expensive relative to other natural gas technologies;
- The costs of both single and double geothermal flash technologies were grouped into one technology due to a lack of available data; and
- The cost of imported electricity was based on the MPR. For both base and intermediate-load imported electricity, the cost of imports was assumed to be equal to the levelized cost of the baseload MPR. The price of daily peak and season peak-load imports was assumed to be equal to the peak-load MPR.

State Regulation Assumptions

The model incorporates most of the Energy Commission’s decisions regarding RPS rules that have been finalized during Phase 1 and 2. Based on conversations with Dan Adler of the CPUC, the pending decisions addressed in the CPUC’s preliminary report [63] are assumed to be final decisions within the analysis even though this is not the case. Namely, the model excludes eligible out-of-state renewable generators and only accounts for in-state

renewable projects, since data for renewable resources outside of California were unavailable.

In addition, the model assumes that all renewable projects are owned and developed by non-electrical corporations and non-publicly owned entities. This is significant because SB 1038 states that facilities that are publicly owned or are owned by electrical corporations may not receive SEPs [8]. The model assumes that since non-IOU entities have a competitive advantage for developing renewable energy (through the eligibility of SEPs), electrical corporations and publicly owned utilities will not produce new renewable projects.

Model Limitations

Electricity markets, especially the large California electricity market, are enormously challenging to model. There are innumerable complications that impact the price and availability of electricity including, but not limited to, transmission service charges (bottlenecks), unpredictable changes in demand (such as due to weather), and changes in the price of fuels. The following is a list of improvements that would have enhanced the model's ability to more accurately mimic the California electricity market.

Least-Cost, Best-Fit

An IOU bases its PPA decisions primarily on the least-cost technology but also on “best-fit” considerations. The most obvious best-fit consideration is the need for peaking plants to provide electricity during peak load times. Other best-fit considerations are the capacity credit of an energy source, which is essentially a rating of its reliability. The model, admittedly, was limited to least-cost decisions.

Transmission

A crude estimator of capital transmission costs was incorporated into new projects costs; the cost of transmission service and upgrades were not included. All transmission costs were correlated to a plant's geographic location. The capital cost of transmission was calculable since it was a function of the average distance of a technology from existing transmission lines and such data was available [64]. The cost of transmission service and upgrades, however, was a function of a plants position relative to transmission bottlenecks and electricity demand. Such an approach would require a GIS-type model that was beyond the scope of this analysis. However, that approach was used by Sezgen et al. to model the cost of future wind generation in California [64]. Even had such a model been applied to this analysis, it is not clear if the costs could be accurately predicted since the Energy Commission has claimed that, “the probability of congestion of certain transmission links does not demonstrate a definite pattern. As load changes between the scenarios, the power flows usually change not only in magnitude but also in direction” [10].

Quantification of Ratepayer Benefits

Although the model quantifies the direct costs of the RPS to the state of California, the indirect costs and benefits to ratepayers has not been quantified.

Intermittency

Some renewable technologies, such as wind and solar sources, are intermittent in nature. That is, the source of energy, such as the wind or sun, cannot be controlled and therefore the electricity is produced “as available.” Although the capacity factors of these technologies can be generalized based on historical generation in certain regions, it is impossible to perfectly predict the performance of these technologies. The model uses capacity factors derived from both calculated and published sources [59].

Regional Considerations

The California RPS applies to the three IOUs: PG&E, SDG&E, and SCE. The model takes the average of their renewable production in 2002 (11.28%) and uses it as the baseline for the RPS. It is important to note that these three IOUs have significantly different renewable portfolio baselines. In 2002, PG&E produced 9.95% renewable energy, SCE produced 15.02% renewable energy, and SDG&E produced 0.74% renewable energy. This disparity in IOU renewable resource baselines is explained, in part, by differences in local resources. The disparity of locally available renewable potential, and the cost associated with procuring renewable electricity from a remote location, was not quantified in this analysis.

Flexibility Mechanisms

The model does not incorporate flexibility mechanisms, such as deferring 25% of an APT to the following year.

Appendix F: Data Compilation

Table F-1: Data used in Model Cost, Capacity, Availability and Transmission Losses

Technology	Type (t)	Costs ¹			Capacity (KW)				Availability (a)			Transmission Losses ⁵
		Overnight Costs	Capital (c) (\$/kW)		Existing ¹ MW	Near-term Proposed ² MW	Future Potential MW	Published ³ %	Calculated ⁴ %	Percent Losses		
			Levelized Capital Costs	Transmission ²							O&M (o) (\$/MWh)	
Coal Plants	Steam/Electric	\$1,154.00	\$0.00	-	550	0	0	-	33.3%	5.0%		
Hydroelectric	General	\$0.00	\$210.00	-	8,984	0	0	-	99.0%	-		
Hydroelectric	Pressure Release	\$0.00	\$210.00	-	11	0	0	-	99.0%	-		
Hydroelectric	Run of the River	\$0.00	\$210.00	-	645	38	2,099	39.8%	99.0%	-		
Total Hydroelectric		-	-	-	9,640	38	2,099	-	43.2%	2.5%		
General/Advanced Nuclear		\$2,117.00	\$0.00	-	4,310	0	0	-	37.8%	5.0%		
Natural Gas	General	\$0.00	\$100.00	-	4,331	0	0	91.6%	28.8%	5.0%		
Natural Gas	Combined cycle	\$0.00	\$90.00	\$2.83	9,370	8,522	10000*	91.6%	28.8%	5.0%		
Natural Gas	Combustion Turbine	\$0.00	\$78.00	\$0.27	5,334	51	1000*	94.0%	28.8%	5.0%		
Natural Gas	Fuel Cell	\$0.00	\$417.00	-	1	0	0	90.0%	28.8%	0.0%		
Natural Gas	Pumped Storage	\$0.00	\$210.00	-	1,834	0	0	90.0%	28.8%	2.5%		
Natural Gas	Steam/Other	\$0.00	\$100.00	-	12,852	0	0	90.0%	28.8%	5.0%		
Total Natural Gas		-	-	-	33,722	8,573	11,000	NA	-	-		
Solar	Photovoltaics	\$0.00	\$423.00	-	2	21	9,451	24.0%	26.0%	5.0%		
Solar	Thermal-Stirling Dish	\$0.00	\$489.00	-	406	85	66,161	30.0%	26.0%	1.5%		
Total Solar		-	-	-	408	106	75,612	-	-	-		
Wind	Class 6	\$0.00	\$174.00	\$79.46	1,808	964	4,782	31.0%	21.6%	5.0%		
Wind	Class 5	\$0.00	\$174.00	\$79.46	1,808	1,927	9,564	25.0%	17.7%	5.0%		
Total Wind		-	-	-	3,616	2,891	14,346	-	-	-		
Biomass		\$1,763.00	\$0.00	-	690	615	2,038	67.0%	64.8%	2.5%		
Landfill	Landfill gas	\$1,460.00	\$0.00	-	161	110	467	75.0%	64.8%	2.5%		
Municipal	MSW	\$1,460.00	\$0.00	-	384	70	467	75.0%	64.8%	2.5%		
Geothermal	Binary (35 MW)	\$0.00	\$628.00	\$138.72	126	0	0	72.0%	80.0%	-		
Geothermal	Double Flash	\$0.00	\$369.00	\$138.72	424	0	0	72.0%	80.0%	-		

Geothermal	Single Flash	\$0.00	\$369.00	\$138.72	\$1.30	30	0	0	72.0%	80.0%	-
Geothermal	Dry Steam	\$0.00	\$369.00	\$138.72	\$1.30	1,808	442	4,735	72.0%	80.0%	-
Total Geothermal		-	-	-	-	2,388	442	4,735	-	-	2.0%
Imports	Base	\$0.00	\$90.00	-	\$40.59	10000*	5000*	5000*	99.0%	99.0%	-
Imports	Intermediate	\$0.00	\$90.00	-	\$40.59	10000*	5000*	5000*	99.0%	99.0%	-
Imports	Daily Peak	\$0.00	\$78.00	-	\$62.11	10000*	5000*	5000*	99.0%	99.0%	-
Imports	Seasonal Peak	\$0.00	\$78.00	-	\$62.11	10000*	5000*	5000*	99.0%	99.0%	-

¹ Source: [65], [27]

² Source: [27], [2]

Note: The "proposed capacity" only represents half of the capacity presented in the original dataset since that data was based on responses to RFPs.

³ The decision to use half of the capacity was an arbitrary choice.

⁴ Source: [59]

⁵ See Table F-2 for details of calculation

⁶ Source: [59]

⁶This adjustment was an arbitrary percentage reduction of the near-term expected project construction based on the fact that the data was obtained by the CIEC from the total capacity of responses to the RPS's first round of RFPs.

⁷The capital cost of transmission for geothermal, single cycle and combined cycle natural gas were derived from the average capital costs of transmission for projects listed on the CIEC's "Siting Cases" website (www.energy.ca.gov/sitingcases). In the case of wind, these average costs per distance were applied to average distance of wind projects from transmission lines (assumed to be 8.3 miles).

* These capacity values were set at high values either because the new capacity was unconstrained (in the case of new natural gas plants) or was constrained by other factors (such as historical constraints on imports)

Table F-2: Calculated Availability of Existing Plants in California

Technology	Existing California Capacity in 1998 ¹ (MW)	Theoretical Generation Capacity ² (MWh)	Actual Production ³ (MWh)	Inferred Availability
Biomass + MSW	971.02	8,506,135	5,507,911	64.8%
Coal	572.59	5,015,888	29,036,867	578.9%*
Geothermal	2,428.80	21,276,288	12,681,333	59.6%
Hydroelectric	13,893.14	121,703,906	46,013,229	37.8%
Nuclear	4,310.00	37,755,600	39,578,250	104.8%*
Oil/Natural Gas	29,527.41	258,660,112	74,367,890	28.8%
Solar	363.14	3,181,106	827,239	26.0%
Wind	1,676.64	14,687,366	2,889,582	19.7%

¹Source: [26]

²Calculated by multiplying capacity by 8760 hours (per year)

³Source: [31]

*These anomalies can be explained by the fact that prior to 2001, utility-owned shares of coal and nuclear plants outside of California (such as Intermountain and Mohave) and, while their electricity production was included as part of utility-owned generation, the capacity of the plants was not included in this calculation.

Table F-3: Forecasted California Electricity Demands and RPS Requirements-2001 to 2017

Year	Total State (GWh)	Total Utility (MWh)	Normal RPS ¹	Accelerated RPS ²
2001	242,861	164,967,000	NA	NA
2002	241,668	149,793,000	11.28%	11.28%
2003	244,139	151,523,000	12.28%	12.39%
2004	249,809	155,589,000	13.29%	13.47%
2005	255,549	159,776,000	14.30%	14.56%
2006	260,671	163,468,000	15.30%	15.65%
2007	264,276	165,943,000	16.29%	16.74%
2008	268,895	169,243,000	16.68%	17.82%
2009	272,165	171,410,000	17.40%	18.91%
2010	275,829	173,811,000	17.96%	20.00%
2011	279,551	176,265,000	18.52%	20.00%
2012	283,252	178,725,000	19.08%	20.00%
2013	286,139	180,399,000	19.20%	20.00%
2014	290,717	183,581,000	19.29%	20.00%
2015	295,368	186,818,000	19.39%	20.00%
2016	300,094	190,112,000	19.49%	20.00%
2017	304,894	193,465,000	19.58%	20.00%

¹ Source: [2]

²Weighted calculation of IOU compliance schedule

Table F-4: Total Electrical Demand per Load in CA¹					
	Load Factor (L_i) (% of day)	Percent of Total	2002 (MWh)	2010 (MWh)	2015 (MWh)
Base	100.0%	62.3%	93,321,039	108,284,253	116,387,614
Intermediate	83.3%	29.0%	43,439,970	50,405,190	54,177,220
Daily Peak	27.4%	7.4%	11,084,682	12,862,014	13,824,532
Season Peak	3.4%	1.3%	1,947,309	2,259,543	2,428,634
Total			149,793,000	173,811,000	186,818,000

¹Source: [2]

Table F-5: Demand for Imported Generation¹			
	Load Factor (L_i) (% of day)	Percent of Total	MWh
Base	100.0%	60.5%	27,793,253
Intermediate	83.3%	31.2%	14,333,049
Daily Peak	27.4%	7.3%	3,353,566
Season Peak	3.4%	1.0%	459,393
Total			45,939,261

¹See Table F-6 for calculation of starting point

Table F-6: CALIFORNIA ELECTRICAL ENERGY GENERATION, 1995 TO 2002⁽⁶⁾

TOTAL PRODUCTION, BY RESOURCE TYPE, in GWh														
	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001 ⁽¹⁾	2002 ⁽²⁾	Average
Total	252,355	242,343	245,535	242,026	256,719	256,367	253,621	255,080	276,412	275,803	280,496	265,059	272,509	106,767
California Generation:														
Hydroelectric	26,092	23,244	22,373	41,595	25,626	51,665	47,883	41,400	48,757	41,627	42,053	25,005	31,221	16,481
Nuclear	36,586	37,167	38,622	36,579	38,828	36,186	39,753	37,267	41,715	40,419	43,533	33,294	34,353	15,326
Coal	21,402	23,442	32,435	22,907	25,095	17,925	25,460	27,114	34,537	36,327	36,804	27,636	27,817	11,681
Oil	4,449	523	107	2,085	1,954	489	693	143	123	55	449	1,328	481	188
Gas	76,082	75,828	87,032	70,715	95,025	78,378	66,711	74,341	82,052	84,703	106,878	113,145	90,991	34,860
Geothermal	16,038	15,566	16,491	15,770	15,573	14,267	13,539	11,950	12,554	13,251	13,456	13,619	13,867	5,325
Organic Waste	6,644	7,312	7,362	5,760	7,173	5,969	5,557	5,701	5,266	5,663	6,086	6,185	6,261	2,334
Wind	2,418	2,669	2,707	2,867	3,293	3,182	3,154	2,739	2,776	3,433	3,604	3,242	3,546	1,284
Solar	681	719	700	857	798	793	832	810	839	838	860	837	851	333
Other	4	0	2	0	0	0	343	896	230	0	0	0	261	86
Energy Imports	61,959	55,873	37,704	42,892	43,354	47,514	49,696	52,720	47,563	49,487	26,774	40,768	62,859	45,939 ⁽⁴⁾
Utility-owned: Total	139,309	131,866	153,350	154,639	157,589	148,936	147,163	144,799	153,791	130,413	133,353	94,425	99,003	52,594
Hydroelectric	25,612	22,728	22,033	40,440	25,024	50,089	46,660	40,122	47,326	40,593	41,001	24,522	30,777	16,054 ⁽⁶⁾
Nuclear	36,586	37,167	38,622	36,579	38,828	36,186	39,753	37,267	41,715	40,419	43,533	33,294	34,353	15,326
Coal	17,710	20,392	28,806	20,358	22,440	16,788	22,590	24,838	31,836	32,726	33,620	23,676	23,635	10,485
Oil	4,449	523	107	2,085	1,954	489	693	143	123	55	157	381	38	104
Gas	45,262	42,353	54,338	46,738	61,474	39,448	31,856	37,048	27,699	14,995	13,747	11,547	8,891	9,262
Geothermal	9,684	8,700	9,441	8,435	7,842	5,855	5,540	5,302	5,009	1,543	1,252	997	1,150	1,332
Organic waste	0	0	0	0	0	65	59	71	80	73	34	0	152	27
Wind	0	0	0	1	26	13	10	6	3	7	7	7	4	3
Solar	2	3	1	3	1	3	2	2	2	3	3	3	2	1
Other	4	0	2	0	0	0	0	0	0	0	0	0	0	0

(1) Year 2000 data has been revised. Year 2001 & 2002 data are considered preliminary.
 (2) Prior to 2001, utility-owned shares of coal, nuclear plants outside of California, and some firm contracts were not included in the energy imports numbers; they were included as part of utility-owned generation categories.
 (3) If 2001 energy imports had been tallied the same way as the previous years, the utility-owned generation from hydro, coal and nuclear should increase by about 3,000 GWh, 13,000 GWh and 8,000 GWh respectively, while the energy imports from Southwest should decrease by about 24,000 GWh to about 10,000 GWh. The total energy imports would have been about 17,000 GWh, if it had been defined as in previous years. Similar adjustments for 2002 resulted in 38,400 GWh of imports.
 (4) This value is used as the limit on imports for the model and is based on the average of 1998 to 2002, excluding 2000 as an outlier.
 (5) This value is used as the limit on hydroelectric power by the model and is based on the average generation from 1983 to 2002 (some data not shown).
 (6) Source: [62]

Appendix G: Forecast of Natural Gas Prices

Table G-1: Forecast of Natural Gas Prices		
Year	CEC \$/1000 ft ³	EIA \$/1000 ft ³
2001	N/A	\$5.40
2002	\$4.55	\$3.85
2003	\$4.55*	\$5.73
2004	\$4.10	\$4.59
2005	\$3.94	\$4.26
2006	\$4.11	\$4.18
2007	\$4.29	\$4.22
2008	\$4.50	\$4.31
2009	\$4.72	\$4.19
2010	\$4.97	\$4.12
2011	\$5.25	\$4.27
2012	\$5.54	\$4.45
2013	\$5.83	\$4.63
2014	\$6.16	\$4.73
2015	\$6.50	\$4.87

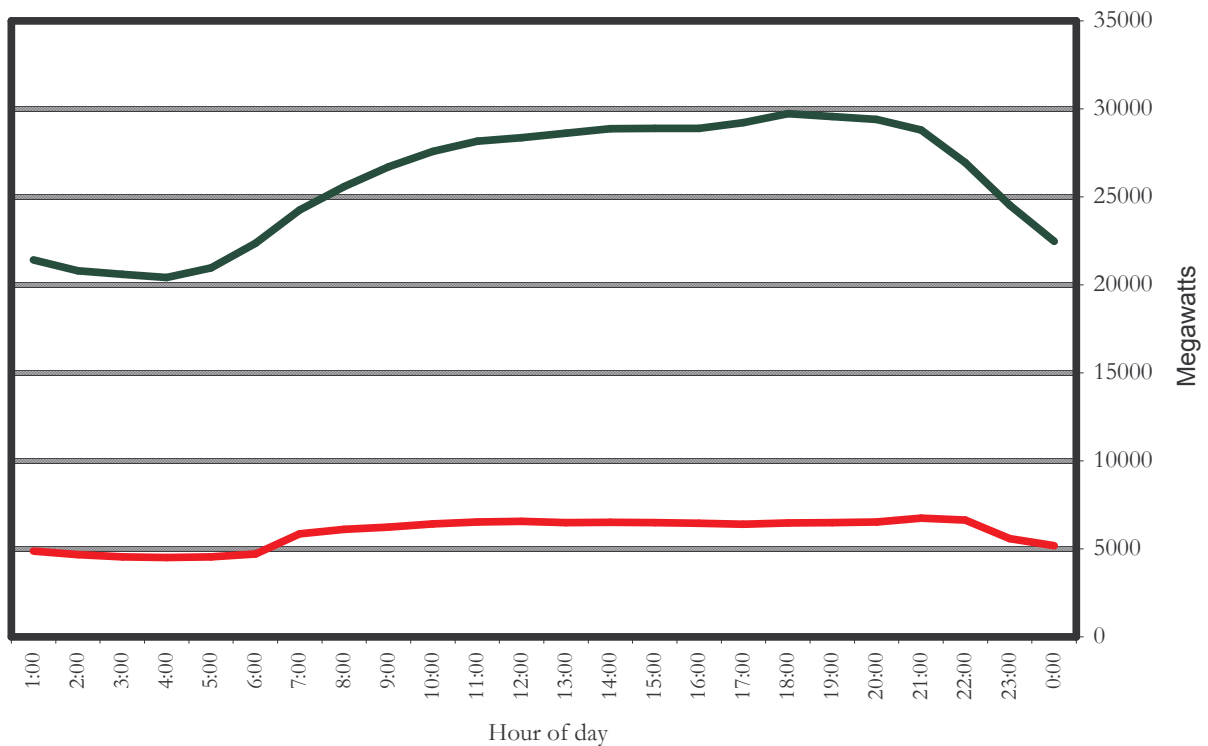
* Assumed present day price of Natural Gas

Source: [60]

Appendix H: Load Duration Curve and Load Factor Methodology

Demand for electricity changes constantly in response to annual activity patterns. Typical demand for electricity is lowest after midnight, until the early morning at which time it increases until mid-day, levels off, and then peaks again in the late afternoon before dropping back down to the baseline demand around midnight. A “load curve” is a representation of this diurnal demand pattern. An average daily load curve for California is shown in Figure H-1.

Figure H-1
Average Daily Load in California
Total Load (black) and Imported Load (red)



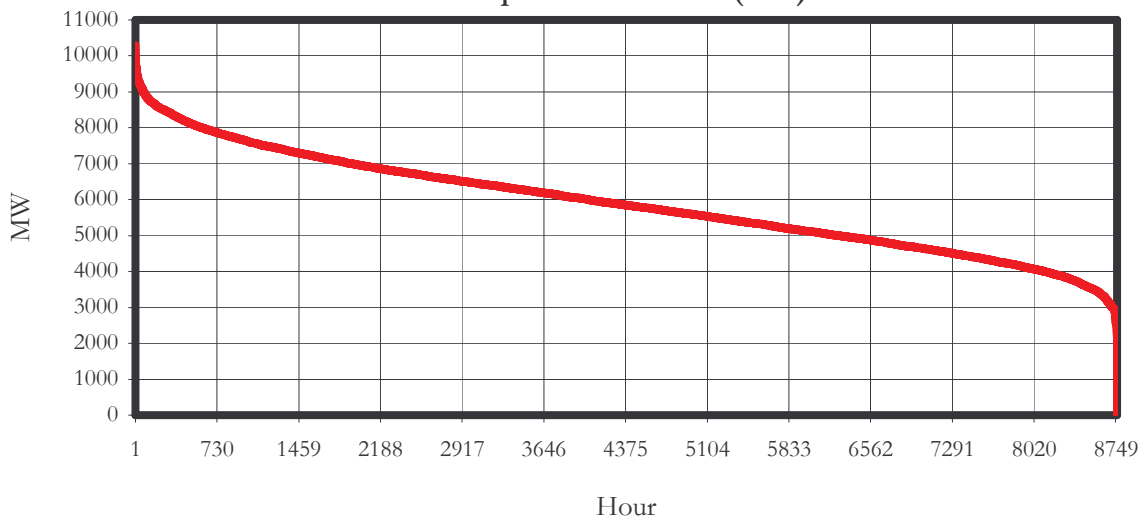
The capacity necessary to satisfy the demand for electricity is equal to the capacity necessary to satisfy the greatest load during the day. As a result, many energy generators must remain idle during a certain number of hours per day. The number of stand-by hours depends on the type of load that the facility serves. Certain technologies, such as combined-cycle natural gas plants, provide primarily “around the clock” service because, although their megawatt-hour operation costs are low, their start-up time is too long to start and stop production on command. These technologies are called “base-load plants”. Conversely, single-cycle natural gas plants are less efficient and have higher fuel costs, but also have a shorter start-up time and therefore are able respond quickly to serve peak loads. Facilities that specialize in serving the peak hours are known as “peaker plants”.

When deciding whether to build a generation facility, an investor must first determine if the project will be profitable. A facility can obtain market data on the price it expects to receive per megawatt-hour for serving a particular load. The other consideration, however, is the number of hours it expects to actually operate per year. A base-load plant investor can assume that there will be a demand for its product 24-hours a day, 365 day a year. A peaker plant, however, must calculate how many hours peak loads can be sustained per day. One approach to making this calculation is to find the “load factor” through a load duration curve (LDC).

The “load factor” is a multiplier that is used to calculate the amount of extra capacity that is needed to produce a given amount of electricity during a specific load. Such a calculation is done to ensure that demand does not exceed supply in any period. Although the load factor itself is essentially an arbitrarily chosen percentage, the amount of electricity generation that it represents is a function of the shape of the LDC. In other words, the size of each load (in time) is not as important as the shape of the LDC since this is what determines the distribution of production across loads [30]. For this analysis, the LDC was separated into four loads. This number of loads was chosen in order to accurately capture the seasonal peak, while not creating false precision.

A typical LDC takes the hourly load data from a given period and graphs each individual hourly load in descending order, as seen in Figure H-2.

Figure H-2
Load Duration Curve for Net Electricity
Imports to California (MW)



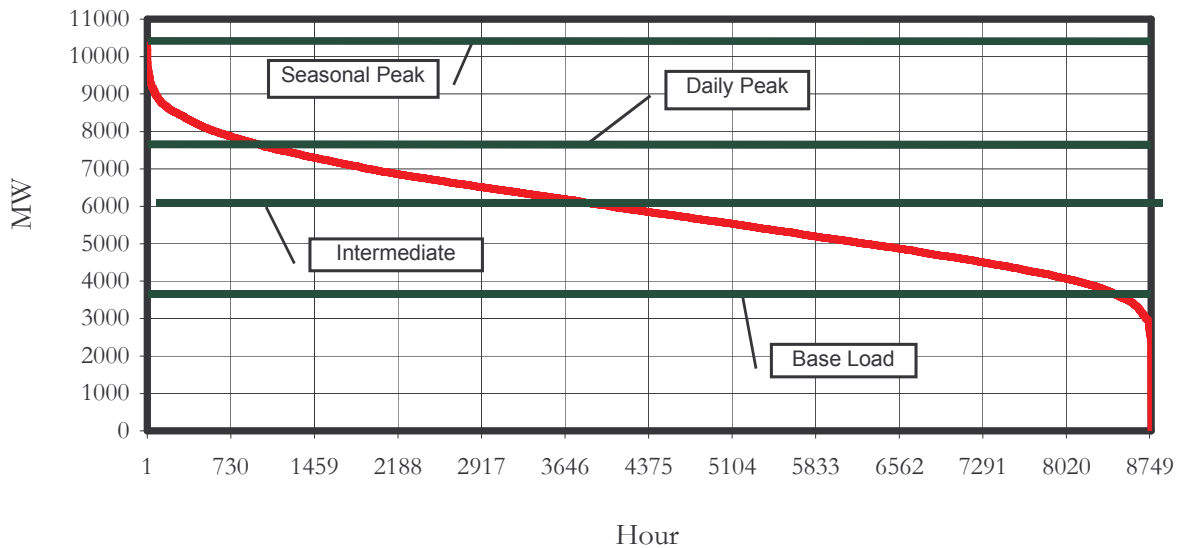
Source: UCEI collection of CAISO data

Hour 1 represents the hour of the period with the largest load while the final hour (hour 8,760 in this case) is the hour of the year that has the lowest load.

The LDC is divided into horizontal planes based on the shape of the curve. As previously explained, the number of loads is arbitrarily assigned. In this case, the LDC is divided into four separate loads: base (100% of year), intermediate (83.3% of year), daily peak (27.4% of year), and seasonal peak (3.4% of year).

By integrating the area under where each horizontal line crosses the LDC, a megawatt-hour demand for each load can be assigned. This demand can also be expressed as a percent of total demand. Figure H-3 shows the integration of the four loads based on data taken from CAISO from August 1, 2002 to July 31, 2003 [29].

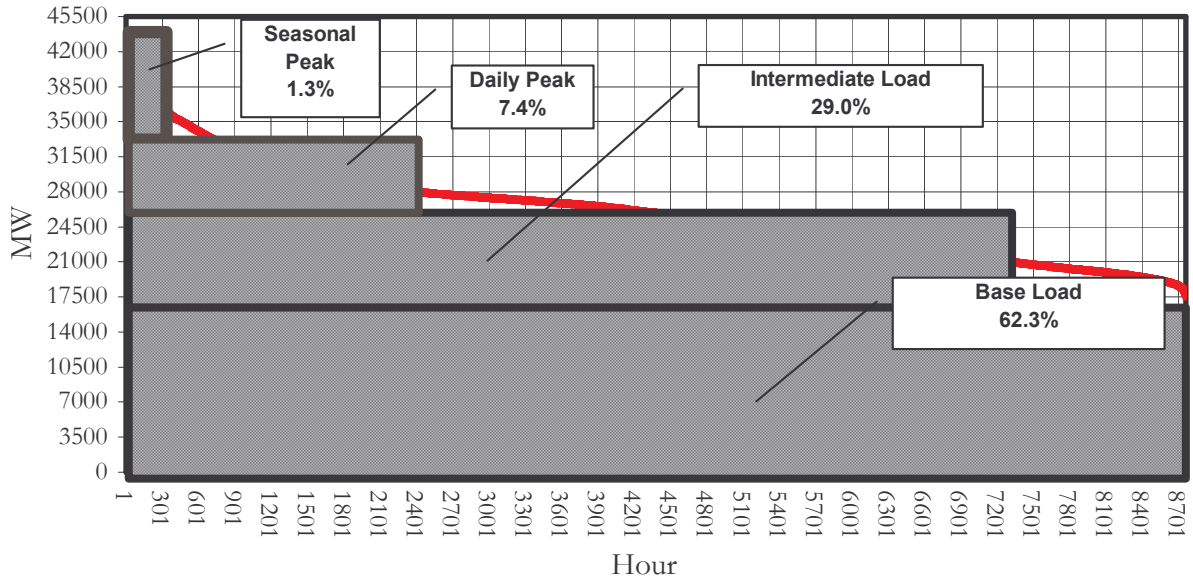
Figure H-3
Load Duration Curve for Net Electricity
Imports to California (MW)



Source: UCEI collection of CAISO data

As demonstrated in Figure H-4, 62.3% of total demand is in the base load, 29% is in the intermediate load, 7.4% is in the daily peak load, and 1.3% of the total demand is in the seasonal peak load.

**Figure H-4
Load Duration Curve for Total
Major Utility Electricity Generation (MW)**



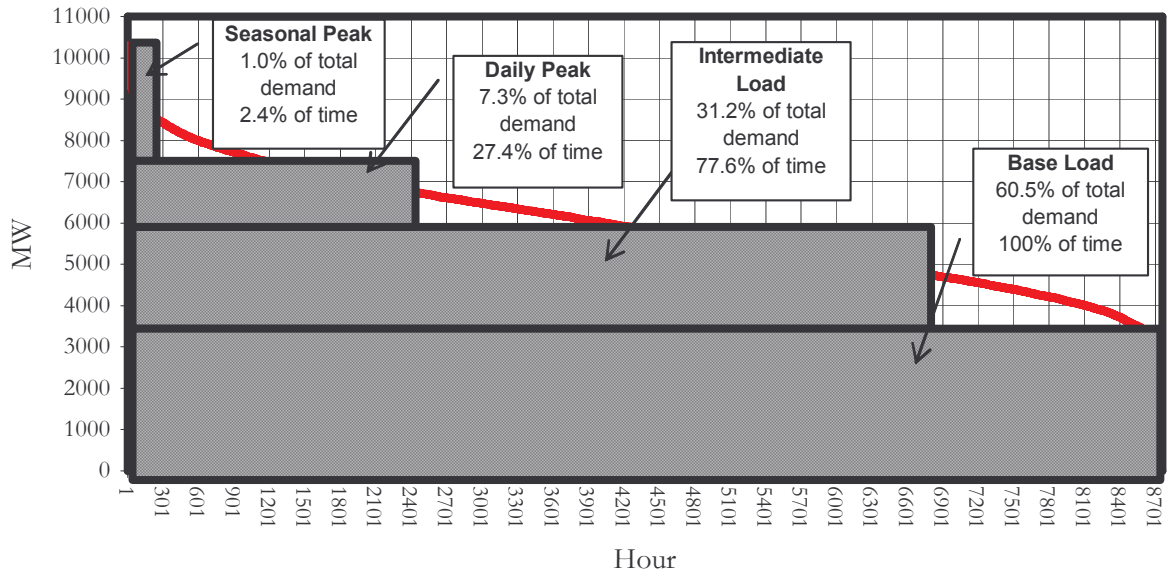
Source: CAISO

Table H-1 is a summary of the integration of the LDC of California electrical demand:

Table H-1: California Demand		
Load	Percent of Time	Percent of Demand
Base	100%	62.3%
Intermediate	83.3%	29.0%
Daily Peak	27.4%	7.4%
Seasonal Peak	3.4%	1.3%

For the purposes of the model, the LDC of electrical imports to California was also integrated (see Figure H-5). The data were taken from CAISO system-wide data for the same time period (August 1, 2002 to July 31, 2003) [29].

Figure H-5
Load Duration Curve for Net Electricity Imports to California (MW)



Source: UCEI collection of CAISO data

Table H-2 is a summary of the integration of the LDC of California imports:

Table H-2: Electrical Imports to California		
Load	Percent of Time	Percent of Demand
Base	100%	60.5%
Intermediate	77.6%	31.2%
Daily Peak	27.4%	7.3%
Seasonal Peak	2.4%	1%

Appendix I: Available TREC Price Data

Because REC markets are still young, there is little data available on price trends. Evolution Markets LLC has comprehensive data on REC trading from July 2003 through January 2004, and is perhaps the best public source of price information for the Texas, Massachusetts, and PJM markets. Additional sources of information regarding the expected behavior of these markets include the REC traders, program managers, and other market participants. This discussion includes interviews with these participants in order to understand the subtleties of REC market behavior.

Market Price Data

Table I-1 provides a summary of the average “last price” for the three primary TREC markets from July 2003 through January 2004 [66].

Table I-1: Average TREC Sale Price	
REC Market	2003 Average TREC Sale Price
Texas	\$13.10
Massachusetts	\$38.45
PJM Class I	\$5.92
PJM Class II	\$3.76

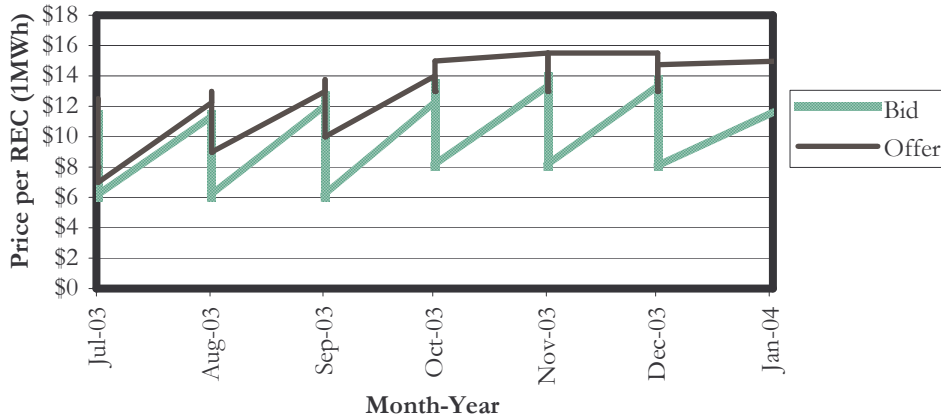
Source: Evolution Markets, LLC

Texas

The Texas TREC market has been characterized by a steady upward trend in prices. However, the bulk of TRECs are still held by a few number of sellers, and many TRECs remain bundled with their electricity when sold [67].

Changes in market price data for Texas can be seen below in Figure I-1. In July 2003, vintage 2002 and 2003 TRECs were priced at \$11.85, while the bids and offers for vintage 2004 through 2006 TRECs were \$4 to \$5 lower. This difference in price was attributed to the uncertainty regarding future supply and demand. In August 2003, REC market activity slightly increased. The market was very active in September with the asking price for 2003 TRECs increasing by \$1 to a total of \$13.75. Activity in the REC market again rose slightly in October, with vintage 2003 TRECs bid at \$13.50 and offered at \$14. Expected discounts in the price of future vintage TRECs demonstrated an uncertainty in the market due to plans for the increased development of renewable projects. November 2003 experienced a rise in TREC prices. The market was very slow in December, with bids ranging from \$13.75 to \$15.50. In January 2004, bids continued to drop to \$12 and \$13 due to an increased market supply. Weaker bids were also attributed to a reduction in the Capacity Conversion Factor for compliance years 2004 and 2005, which in turn reduced the mandatory TREC requirements for those years.

Figure I-1
Texas TREC Market Price Data
July 2003 - January 2004



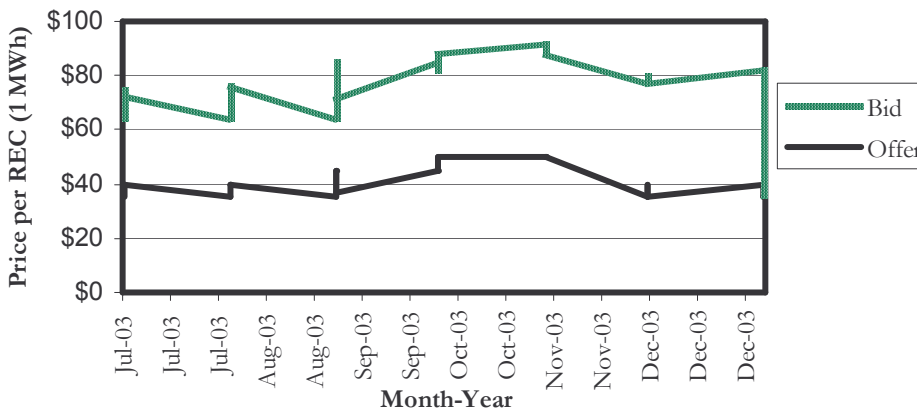
Source: Evolution Markets, LLC

Massachusetts

The Massachusetts TREC market is characterized by having the highest REC prices in the country. Changes in market price data for Massachusetts can be seen below in Figure I-2.

In July 2003 there was a strong interest in purchasing RECs, but there were very few offers. Vintage 2003 RECs traded at \$35.00. There was also great interest in vintage 2004 RECs throughout July and August, as well as RECs that were eligible for both the Massachusetts and Connecticut RPS programs. The price for vintage 2003 RECs ranged from \$38 to \$41.10 from November through December 2003. While there remained a strong interest for vintage 2003 RECs in January 2004, demand for vintage 2004 RECs was on the rise.

Figure I-2
Massachusetts REC Market Price Data
July 2003 - January 2004



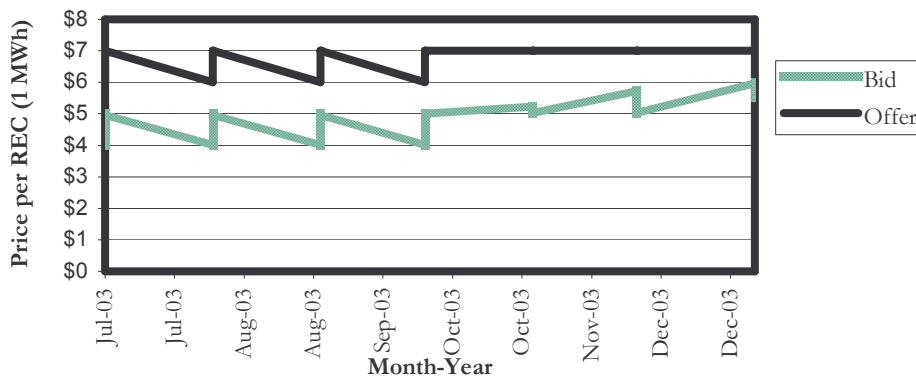
Source: Evolution Markets, LLC

New Jersey/PJM

The New Jersey/PJM REC market is characterized by the lowest REC prices of the four markets. Changes in market price data for New Jersey Class I and Class II RECs can be seen in Figure I-3 and Figure I-4, respectively.

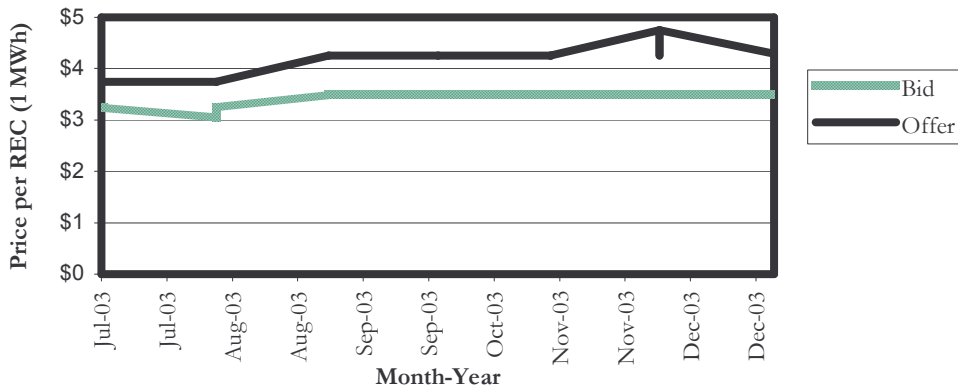
From August through October 2003, there was a strong buyer interest with few available sellers for both Class I and Class II RECs. November 2003 experienced an increase in REC trading for Class I and Class II RECs. The REC market in December was also active and exhibited the highest REC prices of the year, with recorded purchase prices of \$6.50 for Class I and \$4.50 for Class II RECs.

Figure I-3
PJM Class I REC Market Price Data
 July 2003 - January 2004



Source: Evolution Markets, LLC

Figure I-4
PJM Class II REC Market Price Data
 July 2003 - January 2004



Source: Evolution Markets, LLC

Appendix J: Description of Existing TREC Markets

This discussion reviews the current landscape of state RPS programs with a focus on states that permit REC trading for RPS compliance. First, it includes a detailed summary of the New Jersey, Massachusetts, and Texas TREC markets. The characteristics of these markets are compared with California in order to determine the suitability of applying their price market data within a California context. Second, these markets are summarized within a matrix-based system that serves to cross-compare all TREC markets.

State Evaluations

New Jersey's Renewables Portfolio Standard

The PJM is the regional transmission organization for Pennsylvania, New Jersey, Maryland, Delaware, Virginia, Ohio, and West Virginia, and includes the District of Columbia. Currently, New Jersey is the only state that has an active RPS program, which took effect in 2001.

Mandate Specifics

New Jersey is the first and only Mid-Atlantic state to adopt binding renewable energy requirements for all of its electricity providers. A final RPS law has yet to be drafted, but the Board of Public Utilities (BPU) has issued an interim RPS that is currently in effect. While there are no provisions for TRECs in the draft RPS, the BPU and the New Jersey Department of Environmental Protection may decide to include TRECs into the final draft rules.

The interim RPS requires 6% of electricity provided by all load serving entities to be from renewable sources by 2012. While the California RPS currently excludes municipal utilities from the mandatory state procurement requirements, and primarily targets IOUs, ESPs and CCAs, the New Jersey Interim RPS applies to all electric service providers within the state.

Procurement Requirements

The New Jersey Interim RPS requires statewide procurement of 3.25% renewable electricity by 2004, increasing to 6.5% by 2008, of which 4% must be from Class I energy technologies. While these procurement mandates are much smaller than California's 20% renewable requirements, New Jersey is still considering proposed amendments to the RPS and may require a 20% statewide procurement of Class I energy technologies by 2020 for all electricity providers. The New Jersey RPS is also specifically designed to encourage the development of solar energy and sets a goal of 120,000 MWh of new solar generation by 2008 [68].

Eligible Renewable Technologies

Both California and New Jersey allow the same renewable resource technologies to be eligible for their RPS programs. These resources include wind, geothermal, photovoltaic, solar thermal, biomass (which must be sustainably harvested for the New Jersey RPS),

landfill gas, ocean wave, tidal energy, fuel cells, and small hydroelectric generation. The New Jersey RPS classifies small hydro and “waste to energy” resource recovery facilities as Class II technologies, while the remaining technologies are classified as Class I. Although California does not distinguish renewable technologies by class, it does limit the amount of production that is eligible from resources such as small hydroelectric.

In order to be eligible for the New Jersey RPS, renewable energy generation must flow into the PJM or NY ISO interconnect.

Non-Compliance Mechanisms

According to N.J.A.C 14:4-8:8, New Jersey electric power providers who fail to meet their RPS target in a given year could satisfy their kilowatt-hour shortcoming during the following year. If the power provider continues to be in non-compliance, the quantity of missing kilowatt-hours that must be satisfied will compound over time. It is the discretion of the Board of Public Utilities (BPU) as to when appropriate penalties must be enforced. Non-Compliance penalties could consist of one or more of the following:

1. Suspending or revoking license;
2. Imposing financial penalties;
3. Disallowing the recovery of costs through higher rates; and
4. Prohibiting the acceptance of new customers [68].

The BPU will ultimately decide on the severity and relevance of the penalties based on its assessment of the situation of each electricity service provider.

Renewable Energy Credits Program

New Jersey allows only bundled transactions to meet RPS compliance goals. Instead of permitting TRECs, the state recognizes “green for brown swaps” trading as a method of transferring renewable attributes. In this system, a generator will sell green power and then immediately purchase an equivalent amount of brown power, thereby essentially transferring the green attributes to the retailer. Documentation is used to prevent double-counting of the green attributes.

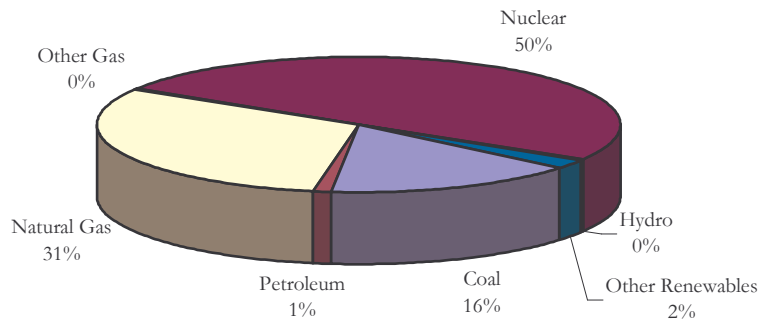
New Jersey is in the process of establishing a generation attribute tracking system (GATS) to facilitate the introduction of TRECs. Once operational, the tracking system will enable electric power suppliers, basic generation service providers, and the Board of Public Utilities to track the type and location of generation, and thus to better determine whether the RPS percentage requirements for renewable energy have been met [69].

Supply of Renewable Resources

There are many small and large renewable generators that contribute to the PJM grid, the majority of which are not located within New Jersey [70]. Consequently, New Jersey has an abundance of renewable electricity available to facilitate RPS compliance. California also has an abundance of in-state renewable resources, and it benefits from the eligibility of out-of-state generators within WECC. However, the degree to which these generators can contribute to the California RPS may depend upon the allowance of TRECs, which would bypass transmission constraints that limit out-of-state generation in a BREC market.

Figure J-1 is a further breakdown of New Jersey 2002 generation sources.

Figure J-1
New Jersey Electricity Generation by Fuel Type, 2002



Anticipated Effects of the RPS

The intent of the New Jersey RPS is to improve air quality and to expand the development of renewable technologies through flexible compliance mechanisms. However, these benefits may not be enjoyed within the state borders because New Jersey does not have a system benefits charge to support renewable development. It is possible that the bulk of renewable resource development would occur within PJM, but outside of New Jersey.

Massachusetts' Renewables Portfolio Standard

The northeast is comprised of six states: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. To date, only Connecticut, Maine, and Massachusetts have enacted RPS programs, and among these states, Connecticut and Massachusetts permit TRECs for RPS compliance. However, since the Connecticut RPS program is currently in a state of flux, this discussion will focus entirely on Massachusetts as the best example of a TREC market within NEPOOL.

Procurement Requirements

The Massachusetts RPS became effective in 2003 and sets a final procurement goal of 4% renewable energy by 2009, with a 1% increase per year thereafter under the discretion of the Department of Energy Resources. Retail Electricity Suppliers (RES) and the owners or operators of new renewable generation units serving load in Massachusetts are obligated under the RPS to comply with the interim renewable targets by the end of each compliance year. A retail supplier includes all entities that sell electrical energy to end-use customers in Massachusetts, which can include electric utility distribution companies supplying standard offer, default service, or any successor service to customers.

The Massachusetts Technology Collaborative (MTC) estimates the 4% requirement translates into 2,386 REC attributes (GWh) in 2009; the RPS purposely did not establish a baseline. In contrast, California must procure 272,165 GWh by 2009.

Eligible Renewable Technologies

A technology is eligible for the RPS if it is online after December 31, 1997 and uses one of the following fuels: solar photovoltaic or solar thermal electric energy; landfill methane or anaerobic digester gas; wind energy; tidal, wave energy, or ocean thermal; or biomass. However, only new facilities established after December 31, 1997 can qualify [67].

Non-Compliance Mechanism

If retailers do not meet their targets, they must make an Alternative Compliance Payment (ACP) to the Massachusetts Technology Park Corporation, administrator of the public funds for renewable development. For compliance year 2004, the ACP is set at \$54.41 per megawatt-hour [71]. Further penalties may include agency and public notifications, and requirements for improving future renewable resource planning.

Renewable Energy Credits Program

The market for all renewable energy in New England is facilitated by a regional Generation Information System (GIS) administered by APX, Inc. and under contract to the New England Power Pool (NEPOOL).²⁷ Since January 1, 2002, retail electricity suppliers are permitted to purchase REC contracts, which can be bundled or unbundled with the electricity. For Massachusetts RPS eligibility, TRECs are allowed, but the underlying electricity must be delivered to the ISO-NE grid and must include associated transmission rights for delivery. Eligible TRECs must have their generation certified and registered within the NEPOOL-GIS system. Upon receipt and verification of the electricity delivery, the green attributes cannot be claimed in any jurisdiction other than Massachusetts.

In December 2003, NEPOOL established an account to be used for banked RECs in order to allow REC holders to carry their RECs from one period to the next throughout a compliance year. Although it is a common flexibility mechanism in many RPS programs, the banking of RECs is limited within the Massachusetts RPS. Compliance banking is permitted in both of the two subsequent compliance years; that is, if a RET over-complies one year, it can apply the excess, up to 30% of that year's target, to the two following years. Banking of RECs is not allowed.

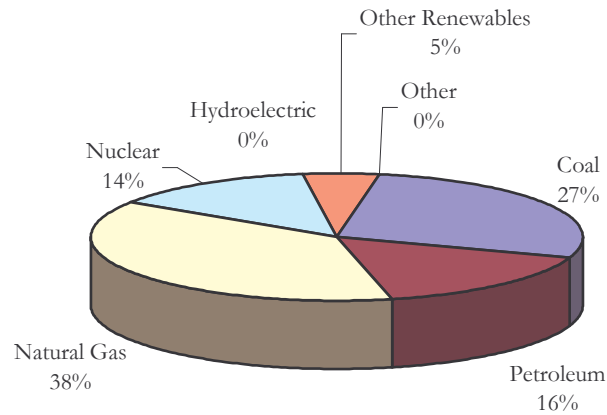
Supply of Renewable Resources

The EIA Annual Electricity Outlook reported that the northeast generated 11.76 billion kWh of renewable electricity (this includes conventional hydropower). The resulting attributes are eligible for Massachusetts' compliance.

Figure J-2 is a further breakdown of Massachusetts 2002 generation sources.

²⁷ The GIS is a sophisticated database that tracks the all the power generated and sold in New England, which is done by assigning each electricity generator as well as any imports into New England one GIS Certificate for every MWh of electricity production. All generators and retailers in New England maintain GIS accounts. The Certificates describe the mix of generation (e.g., the fuel sources, vintage) in their possession. If a GIS Certificate is assigned to a MWh of electricity generated from a renewable energy, that certificate is known as a Renewable Energy Certificate.

Figure J-2
Massachusetts Electricity Generation by Fuel Type, 2002



Other Differences

Massachusetts, similar to New England states, has high electric rates compared to the rest of the nation. Because it is situated in the northern region of the United States, Massachusetts has a seasonal climate with extremes of heat waves in the summer and below freezing temperatures in the winter. Since the majority of its population and industry is located in and around Boston, Massachusetts has centralized peak loads and demand for electricity, while the majority of the state has very little demand [72].

Anticipated Effects of the RPS

In the upcoming year, it is expected that the demand for 2004 credits will exceed supply. Because the market is still young, it has not yet established an equilibrium; consequently, supply and demand are very difficult to predict.

Texas' Renewables Portfolio Standard

Mandate Specifics

Texas is not only one of the oldest mandatory REC markets, it is also the sole example of an existing intra-state TREC market. The Texas RPS was contained within Senate Bill 7, the Public Utility Regulatory Act (PURA) of 2001 [73]. Entitled "Goal for Renewable Energy," the Texas RPS utilizes a capacity-based standard that requires the installation of 2,000 MW of new renewable generation by 2009 through 2019.

Similar to California, the Texas RPS applies to IOUs, ESPs, and CCAs, which it categorizes as "customer choice retailers". Any electricity provider that does not offer customer choice, such as municipal utilities and distribution cooperatives, is excluded completely from the Texas RPS mandates [74]. The state has established firm interim targets of new renewable

capacity, and each entity must calculate the percentage of its total load for that year, relative to the state's total electricity load. This percentage is then applied to the interim target to determine the entity's required annual compliance [75].

Both California and Texas permit out-of-state renewable generators to be eligible for the RPS. However, these generators must meet strict requirements in order for their generation to be applicable for a utility's compliance targets. In California, an out-of-state generator must meet one of the following criteria: either it is located near the border with the first point of connection to the WECC transmission system within California, or it is connected to WECC and holds guaranteed contracts to sell its generation to California IOU customers [7]. The CEC is still deliberating as to whether out-of-state generators will qualify for SEPs [2].

The Texas RPS has very similar requirements for out-of-state generators. Like California, the generator's first metering point must be within the state (of Texas). Additional criteria require all of the metered generation to come from the same facility and the generator to be certified by the PUCT [76].

Procurement Requirements

Perhaps the most significant difference between Texas and California is the total procurement goal of the state RPS. The original California RPS goal required a statewide procurement of 20% renewable electricity by December 31, 2017. However, the Energy Action Plan that was drafted by the CEC, CPUC, and the CPA accelerated this 20% RPS target date to 2010 [77]. Under either set of targets, once 20% renewable procurement is reached by each participating entity, it is to be maintained until the final year of the RPS in 2017 [2].

In contrast, Texas has a capacity-based standard that requires the installation of 2,000 MW of new renewable capacity by the year 2009, to be maintained as a minimum through 2019. The total quantity of in-state generation required by the Texas RPS is anticipated to be approximately 3% of total retail sales in 2009 [78], which is 17% less than California's final target, relative to retail sales. However, Texas is already demonstrating a development of renewable energy sources that has far exceeded the requirements of the RPS interim targets, and was expected to fulfill the final state target of 2,000 MW by the year 2004 [79]. It is anticipated that the RPS program will be extended beyond 2019 with a new capacity target [39]. Consequently, the Texas RPS has proven to be quite successful in meeting its goals for new renewable in-state capacity.

Eligible Renewable Technologies

Similar to California, existing and new renewable facilities can be used for compliance under the Texas RPS. However, only new facilities in service on or after September 1, 1999 qualify for Texas TRECs, with the exception of small producers of less than two megawatts [80]. Facilities greater than two megawatt-hours that were constructed before September 1999 can still be used for RPS compliance, but their generated RECs cannot be traded [80].

Texas shares many of the same eligible technologies as California; the RPS allows wind energy, geothermal, solar energy, hydroelectric, biomass, biomass-based waste products such as landfill gas, wave energy, and tidal energy. Although the Texas RPS does not limit the size

of eligible hydroelectric facilities, this may not be significant given their small capacity within the state, relative to California. Similar to California, eligible Texan generators must be certified by the PUCT [76].

Renewable Energy Credits Program Administration

In order to facilitate the utilities' efforts to meet their procurement targets, the Texas RPS allows the use of TRECs for annual compliance. PURA §39.904 charged the Electric Reliability Council of Texas, Inc. (ERCOT) with the role of establishing and implementing a Renewable Energy Credits Program.

While less involved with the implementation, the PUCT has been charged with receiving, evaluating, and responding to certification applications from renewable energy generators. The PUCT is also the primary agency for developing and administering non-compliance penalties [76].

Generally, Texas is credited with having established an excellent TREC tracking system that incorporates effective enforcement measures [80].

RPS Accounting System

Analogous to the electronic-path system being developed by the Energy Commission, Texas established a web-based accounting system that tracks the issuance, registration, trade, and retirement of RECs [80]. While the buying and selling of RECs is still within the private market, the transfer of RECs from the buyer to the seller does not take place until ERCOT distributes the RECs into the seller's account, which occurs a minimum of 59 days after the end of each quarter [75]. In order to calculate and distribute the appropriate number of RECs to renewable generators throughout the year, ERCOT operates on a quarterly schedule.

To verify annual compliance, the California RPS requires utilities to submit their filings on February 1st of the following year, thereby documenting whether APTs were met. The filings must include information on any past deficits, anticipated future deficits, and the reasons for these deficits [2]. The Texas RPS provides utilities with two additional months, requiring that utilities submit their compliance RECs by March 31st of the following year.

TREC Eligibility

The California Energy Commission is still considering whether TRECs will be permitted under the RPS, although it notes that TRECs may help avoid congestion in transmitting electricity from WECC to California [2]. If California does not permit TRECs, utilities will be required to procure their APT through either direct generation or direct contracts with renewable generators.

Texas allows TRECs for 100% of a utility's RPS compliance. However, a large percentage of these RECs are actually tied up through long-term contracts. In spite of these contracts, companies still prefer TRECs because of their flexibility for responding to changing market prices [39]. REC offsets can also be used to satisfy compliance targets, but these cannot be traded. A REC offset is defined as any renewable generation that reduces the demand for electricity at a site where it can be consumed, and is equal to one megawatt-hour of renewable electricity from a facility that was in operation before September 1, 1999 [76].

Flexibility Mechanisms

California and Texas allow comparable flexibility mechanisms such as banking excess renewable procurement and permitting temporary deficits in a utility's RPS compliance. Under the California RPS, utilities receive credit for any procurement that exceeds their current APT, which can be applied to a future year's APT [2]. Similarly, the Texas RPS extends the life of a REC to three years, allowing a REC to be used either in the year it is generated or to be banked for an additional two years [76].

The California allows utilities to incur a maximum APT deficit of 25%, which must be met within 3 years. In order to qualify for deficits, utilities must meet one of the following criteria: an insufficient response to "requests for offers", proof that existing contracts will compensate for the deficit, insufficient PGC funds for SEPs, or a failure of the generator to fulfill contracts [2].

Texas' regulations regarding deficits are much more stringent. The RPS permits a smaller procurement deficit of 10%, which must be satisfied within the following year to avoid a non-compliance penalty [75].

Penalties

Both states have included the same non-compliance penalty level within their RPS. California will charge utilities 5 cents per each kilowatt-hour that is short of the APT, with a maximum cap of \$25 million per utility. Comparably, utilities that fail to comply with the Texas RPS must pay the lesser penalty of \$50 per each megawatt hour that has not been met, or 200% of the average market value of the missing RECs from that compliance period [81]. As no penalties have been levied in Texas to date, these penalty levels may be considered fairly effective [39].

Funding Sources

Texas and California differ in their funding structures for the state RPS programs. While the state of Texas does not directly fund renewable generators, California generators can qualify for funding from one of two programs. First, the California RPS allows the CEC to provide funding from the PGC fund to assist new renewable generators in covering above market costs. A second funding program was established by SB90 in 1998, which provides eligible facilities with a maximum of 1.5 cents per kilowatt-hour for their first five years of generation.

While all eligible renewable technologies are equally considered for siting projects under the Texas RPS, California ranks funding for projects based on best-fit criteria. Best-fit describes the technology's ability to meet the utility's energy, capacity, ancillary service, and local reliability needs [2].

The Texas RPS does not allocate ratepayer funds for renewable generators. However, ERCOT stakeholders have agreed to pay a renewable generator's "out of merit" operation expenses incurred from a forced curtailment of generation due to transmission constraints. These expenses are eventually charged to the load entities [39]. In direct contrast to the Texas program, the California RPS will not reimburse generators for curtailments, but will only pay for actual generation by a renewable resource [46].

Other Incentives

Federal and state incentives have benefited the development of renewable energy resources within California and Texas. For example, both states have seen a rush in wind development resulting from the anticipated expiration of the PTC, most recently in 2003 [79]. The Federal Renewable Energy Production Incentive also gave annual payments of 1.5 cents per kilowatt-hour to new renewable generators from October 1, 1993 to September 30, 2003 that were owned by state or local governments or non-profit organizations [2]. Additional state programs are listed below in Table J-1.

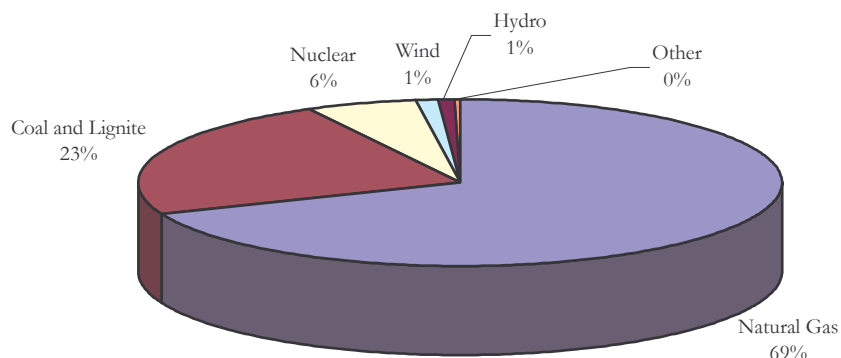
Table J-1: State Incentive Programs for Renewable Resource Development	
California	Texas
<ul style="list-style-type: none"> • Emerging Renewable Program: Gives rebates to IOU customers with grid-connected small wind systems or photovoltaics of 30 kW or less • Self-Generation Incentive Program: Gives rebates to IOU customers with photovoltaics greater than 30 kW • City bond initiatives for development of renewable technologies • Customer Credit Program: Rebates of up to 1 cent/kWh for 2001 customers of ESPs • CPA financing of significant renewable generation projects • Municipal subsidies for photovoltaics 	<ul style="list-style-type: none"> • Green Pricing Programs: Arrange long-term contracts with customers for renewable electricity at fixed prices • Franchise tax exemption for companies that manufacture, sell, or install solar energy devices • Corporate tax credit for purchase of solar energy device [82]} • Property tax exemption to homeowners who install wind or solar energy technologies • Net metering rules allowing customers to receive credit for energy sent into the power grid

Sources: [2], Texas Homeowner Incentives for Renewable Energy, DESRI

Supply of Renewable Resources

In 2002, California reported an in-state renewable electricity procurement of 11%, while Texas was at 1.8%. According to these percentages, both states had already fulfilled more than half of their total RPS targets by 2002. Figure J-3 illustrates the 2002 Texas fuel source portfolio.

Figure J-3
Texas Generating Capacity by Fuel Type, 2002



Source: {Texas Public Utilities Commission, 2003 #88}

As seen in Figure J-3, Texas relies predominantly on natural gas as the primary fuel source for the state, which is similar to California. The secondary fuel sources differ with coal in Texas and nuclear in California. Primary renewable technologies also differ for each; Texas' largest percentage of renewable capacity is wind, while California is dominated by geothermal, with wind being the third most developed resource.

Differences in Energy Costs

The cost of implementing each state's RPS will depend primarily on the types of renewable resources that are developed, and the relative cost of each technology.

The Texas RPS is primarily supported by the development of wind energy, which is the least expensive renewable technology. Consequently, while Texas is meeting the RPS with a least-cost approach, the RPS is not making any provisions for renewable resource diversity [80].

In contrast, California has already developed a variety of renewable resources, and its RPS was designed to ensure the use of both least-cost and best-fit technologies. However, because wind energy from Kern County alone could meet statewide APTs through 2008, wind will certainly have a significant role in the California RPS. Other technologies that are expected to contribute to APTs include a significant amount of geothermal; smaller amounts of LFG, anaerobic digester gas, and solid fuel biomass; and a small amount of concentrating solar power [2]. It can be assumed that an increased development of non-wind technologies will also increase the cost of RPS compliance, relative to Texas.

Regarding the cost of conventional technologies, both California and Texas depend heavily upon natural gas. As a second source of conventional energy, Texas utilizes coal, which is much less expensive than California's use of nuclear energy. However, California also utilizes a large supply of hydroelectric power that can be very inexpensive. Consequently, California and Texas may have similar costs of conventional energy.

Transmission Constraints

A significant factor in the development of renewable energy is current transmission congestion and available funding for future transmission projects. Both California and Texas struggle with transmission constraints that may limit the delivery of renewable generation.

In California, 75% of renewable resources identified for state RPS compliance are located in four major areas that would require transmission upgrades to allow access. The CPUC has developed a renewable transmission plan that considers the added transmission pressures of an accelerated RPS. Specific transmission constraints include the Salton Sea and Tehachapi, which may delay renewable energy procurement and the state's ability to meet its APTs [2].

Texas has experienced an overdevelopment of wind capacity in the western part of the state. Although current transmission is limited to approximately 400 MW, an estimated 1,058 MW of new wind capacity was planned for the end of 2003 due to a lack of incentives for generators to develop in less congested regions. The PUCT has recently revised its approval guides to facilitate the siting of future transmission lines [79]. However, it is much quicker to build new wind capacity versus new transmission facilities, and ERCOT has not been able to keep pace with the new capacity. Future transmission projects are also expected to increase the transmission rates to ERCOT customers [79].

Differences in Market Knowledge of Buyers

California has benefited from the existence of a previous voluntary REC market, which has provided participants with a framework for predicting the future behavior of a mandatory market. On account of such prior experience, these states may be better suited to shaping effective RPS programs. Although Texas has not enjoyed these benefits, the RPS program has been very successful. This may be attributed to the state's commitment to training market participants in the available tools, compliance rules, and operating protocol, in order to develop a familiarity with the program. ERCOT also attributes the success to its stakeholders, who have the freedom to question and challenge the RPS process as it develops [39].

Anticipated Effects of the RPS

To date, the RPS has succeeded in reaching its procurement targets. In fact, early 2004 estimates indicate that Texas currently has 1,186 MW of new capacity [39]. In preparation for the 2005 interim target of 450 MW, many retailers are currently purchasing RECs in order to bank them over the next two years.

Some analysts have considered the Texas RPS to be a prototype for other states. According to Ryan Wiser of the Lawrence Berkeley National Laboratory, the success of the Texas RPS can be attributed to the "ease of wind project siting, outstanding wind resources, and conducive transmission rules" [83].

ERCOT has some concerns regarding the effects of out-of-state generators on in-state renewable development. Eligible out-of-state RECs are not included in the annual calculations of Texas' installed renewable capacity. Consequently, it is possible that there will be a sufficient quantity of RECs for retailers to meet their RPS targets, while the state remains short of its in-state development goal [76]. However, there has been no evidence to

suggest that out-of-state generation is currently limiting the development of new in-state capacity.

Matrix Comparison of Mandatory TREC Markets

The following matrix provides a comparison of the three existing mandatory TREC markets with the developing California REC market.

	California	Texas	Massachusetts	New Jersey
RPS goals (quantity and time)	20% of retail sales by 2017 for each investor owned utility	2,000 MW of new capacity by 2009, to remain constant through 2019.	4% new eligible renewable energy by 2009, with a 1% increase per year thereafter. Systems installed after December 31, 1997 can qualify as "new". Standard took effect in 2003 at 1% of sales.	6% renewables (at least 4% from only Class 1 Renewables) by 2012
Eligible technologies	Solar thermal, photovoltaic, wind, biomass, landfill gas, digester gas, geothermal, small hydro (30 MW or less), ocean wave, ocean thermal, tidal current, fuel cells using renewable fuel.	Solar, wind, geothermal, hydroelectric, wave energy, tidal energy, biomass, biomass based products (ie. landfill gas).	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Fuel Cells, Tidal Energy, Wave Energy, Ocean Thermal	Class 1- solar, wind, fuel cells, geothermal, wave, tidal energy, landfill gas, sustainable biomass. Class 2- MSW or hydro that meets high environmental standards.
Flexibility mechanisms	Considered deficit banking for up to 3 years, but undecided	RECs have a useful life of 3 compliance periods: the year it is generated plus 2 years that it can be banked.	Electricity suppliers can submit an Alternative Compliance Payment (ACP) to the Massachusetts Technology Park Corporation. For CY 2004, the ACP is set at \$51.41 per MWh. Unbundled REC transactions are allowed, but electricity must be delivered to ISO-NE grid. Compliance banking allowed (2 years), but TRECs can't be banked	Provisions for credit trading and banking, but not established in interim RPS.
Out-of-state eligibility	Only if connected directly to the WECC transmission system	Can be certified and eligible for TRECs if first metering point is in TX.		Open general, Class II technologies must come from states open to retail competition.
Penalties	5 cents/kWh, with cap of \$25 million per utility.	Lesser of \$50/MWh or 200% of average market value of missing RECs.	\$50/MWh fine	Draft Rule would require non-complying retailers to be subject to fine or license revocation or suspension

	California	Texas	Massachusetts	New Jersey
Accounting system	Short-term: contract-path based. Long-term: electronic-path based.	Web-based accounting system managed by ERCOT that tracks the issuance, registration, trade, and retirement of RECs.	NEEPOOL G.I.S.	Compliance filings due April 1 for previous year, with independent verification from an auditor. PJM electronic database monitors participants.
RPS funding	SBC funding , \$135 million/year for 4 years beginning 1998; additional funds provided for renewable energy R&D; fund extended at \$13.5million adjusted for inflation and load growth through 2012.	No ratepayer funding sources	Public Benefits Fund, administered by Massachusetts Technology Collaborative. \$25 million per year for an undefined period beyond 2002	Approx \$32 Million from 2000-2007 with review after 8 years. Funds given by BPU under CA SBC program model
Other incentives for renewables	SB-90	PTC, Green Pricing Programs, tax exemptions, net metering rules.		none
Supply/demand of renewables		Sufficient supply of wind. Demand currently matches supply.		High supply since out-of-state RECs apply. Only subject to transmission supply constraints which are hourly.
Primary conventional technologies	1) Natural gas 2) Nuclear 3) Coal/Hydro	1) Natural gas 2) Coal 3) Nuclear	1) Natural gas 2) Coal 3) Petroleum	1) Nuclear 2) Natural gas 3) Coal
Transmission constraints	Constraints in Salton Sea and Tehachapi.	Overdevelopment of wind in West Texas.		LMP through PJM
Pre-existing voluntary REC markets	Yes	No	Yes, but lack of credits	

Appendix K: The Interstate Commerce Clause

Rules regarding the trade of TRECs are subject to the Interstate Commerce Clause, which places all regulatory power of imports and exports between states and nations in the hands of Congress. Amendments have expanded the language to define *per se*²⁸ discrimination against imports from other states as unconstitutional. Any state that harbors electrical generation facilities bears the costs associated with development, maintenance, any necessary transmission additions and interconnection fees. Also, “absent geographic location the costs (If TRECS) are imposed within the state but benefits can flow out allowing any receiving state to free ride from the renewable energy generating state’s investment. This is a potential political problem in California since California ratepayers are funding SEPs through the PGC” [4].

Maintaining in state benefits by direct *per se* restriction of TRECs or BRECs across state borders is legally subversive. Based on the case *Philadelphia v. New Jersey*, 437 U.S. 617, 624, which invalidated New Jersey’s ban on imports of garbage from Philadelphia, “any prohibition of imports of any kind from out-of-state is considered discrimination by a state from out-of-state resources and is considered ‘per se invalid’ [4]. The garbage import case relates to electricity transfer as it addresses the obligatory allowance of out-of-state resources. An in-region restriction suffers the same legal invalidation.

Unless there are significant changes made to the Supreme Court application of the Commerce Clause in the United States, restricting generation or sale of TRECs to only within California will be found unconstitutional. Therefore, leaving trade unrestricted, but only allowing SEP funding for projects that directly deliver to California is the safest route around the legal issues surrounding the Interstate Commerce Clause.

The California RPS is designed to increase the benefits of renewable electricity generation realized within the state. This can be accomplished by restricting ratepayer funding to projects that keep benefits of renewables in California. Subsidizing TREC generation outside of California presents the potential for loss of in-state economic benefits of renewable generation to out-of-state TREC generators. Restricting the flow of TRECs is intended to prevent other states from “free-riding” on California ratepayer investments in new renewable projects. If the use of TRECs can be achieved while preserving in-state benefits, the RPS compliance strategy will be a success.

International TREC and BREC trade issues also will trigger legal violations with NAFTA. A border state such as California will doubtlessly be faced with the potential for international as well as inter-state imports of electricity. Limiting renewable procurement to within California and not allowing transfer of either bundled or unbundled transactions across national borders will produce benefits that will amass within the state. Like the Commerce Clause, NAFTA does not allow *per se* discrimination against resources imported from Canada or Mexico.

²⁸ The term *per se* as used in this context means specifically discriminating against interstate trade as written in the state law. Often times this violation of the interstate commerce clause is avoided by finding ways to disincentivize trade or make in-state resources more attractive through the use of taxes or subsidies.

How other States have handled the Commerce Clause

Some states with renewable programs have found methods of avoiding legal roadblocks that are inevitable with placing geographic limitations of renewable resource imports or exports (either bundled or unbundled). Texas, for example, has in no way prohibited inter-state trading of RECs. However, it has assured that generation remains in-state by creating a stipulation that “all participating (tradable credits) in the trading program represent actual megawatt-hours of renewable energy for consumption by Texas retail customers” [74]. Although this is indirect prohibition of out-of-state resources *per se*, interstate trade in Texas is unique in that it is limited by proximity and availability of transmission that is within ERCOT. Texas has created a rule that requires all generation sources from outside ERCOT to be subject to prohibitive wheeling charges.

New Mexico has implemented a state production tax credit equal to one cent (\$.01) per kilowatt-hour for the first four hundred thousand megawatt-hours of electricity produced by the qualified energy generator using a qualified energy resource in the taxable year [84]. This type of incentive would be beneficial for use in California, as it would lower cost of production for in-state renewable generation. This will likely reduce the price to California ratepayers and promote more in state development of renewables, thus creating more TRECs (as well as bundled transactions) from in-state generation.

An example of where state law compatibility comes into play is in Nevada²⁹. The intention of the Nevada RPS is to create jobs in-state as well as to promote the benefits of renewable generation regionally. However, state law in Nevada requires that Nevada utilities be required to only buy in-state RECs. The state has also limited eligible technologies to “renewable energy system”, defined as one that is tied in with Nevada transmission system or is wheeled in as the only system on an inter-state line. This serves as a legal limitation to inter-state trade by requiring that any state must have an overlap of eligibility requirements (which is unlikely). Nevada is, however, cooperating with California because of resource limitations within its state. California can follow a similar model by providing SEP funding only for projects that are defined as ‘eligible in state renewable resources’ by the rules outlined in the Phase 2 Implementation guidebook [6].

²⁹ This information is taken from a conversation with Anne Marie Ballard of the Nevada Board of Public Utilities. Anne Marie is the REC administrator for the state of Nevada.