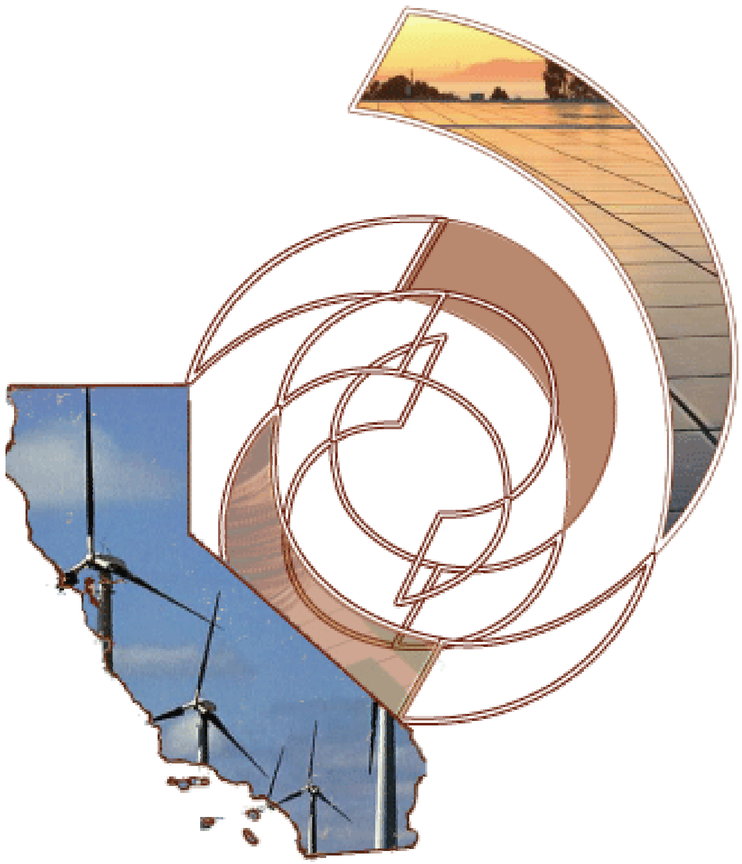
ACHIEVING A 33% RENEWABLE ENERGY TARGET

November 1, 2005



Prepared For:

California Public Utilities Commission

Prepared By:

The Center for Resource Solutions Team

ACKNOWLEDGMENTS

We very much appreciate the work of all the co-authors on this report. Ryan Wiser and Kevin Porter co-authored Section I and V; Ray Dracker authored Section II; David Clement authored Section III; Jennifer Martin authored Section IV; Mark Bolinger prepared the Natural Gas Price Impacts Assessment; Jan Hamrin authored Sections VI, VII and VIII, the Document Summary and served as the overall Project Manager. All the authors contributed to Section IX.

We would also like to thank David Wooley of the Energy Foundation for his guidance with this project as well as CPUC Commissioners and staff for their generous contributions of time and opinions on the project. Theresa Cho of Commissioner Grueneich's office was particularly helpful in setting meetings and ensuring we received the information we needed when we needed it. Thank you also to the CEC Commissioners and staff that made sure we had access to the data we needed as soon as it was available. We also want to thank the many people we buttonholed who graciously agreed to be interviewed on various aspects of the report (they are listed in specific section notes).

ACHIEVING A 33%
RENEWABLE ENERGY TARGET

November 1st, 2005

Prepared for:

California Public Utilities Commission

Prepared by:

Jan Hamrin
Ray Dracker
Jennifer Martin
Ryan Wiser
Kevin Porter
David Clement
Mark Bolinger

Preface

This report was requested by the California Public Utilities Commission (CPUC) and funded by the Energy Foundation. It was developed to assist the CPUC in its responsibilities as part of the California Climate Action Team (CAT), and as an input to the CAT January 2006 report to the Governor on implementation of the state greenhouse gas reduction target,[1] The purpose of the report is to **assess how to accelerate and expand the current CPUC Renewable Portfolio Standard (RPS) and related programs to achieve the Governor's goal of meeting 33 percent of statewide electric power supply with renewable energy by 2020**.[2] This report identifies what the CPUC can do within the scope of its current jurisdiction and what changes in law are needed to expand renewables to meet the Governor's goal. This report also focuses specifically on necessary implementation steps, barriers that must be overcome and a step-by-step schedule for implementation and adoption of policy changes needed to accelerate California's RPS program to the 33 percent level. Wherever possible this project relies on existing research, analysis and modeling results.[3] The period of interest for this investigation is 2010 to 2020.

The tasks identified in the scope of work include:

- Review the status and structure of the current CPUC RPS program;
- Review and summarize existing technical information and programs on renewable resources;
- Identify necessary modifications to ISO procedures, utility transmission expansion decision making, tariffs and protocols to accommodate additional renewable resources;
- Identify incentives and programs to encourage development and use of distributed renewable resources, and to increase renewables in voluntary renewable energy markets;
- Analyze how the RPS and other related programs mesh with a greenhouse gas reduction program; and
- Examine the costs and benefits of the 33 percent goal from a ratepayer perspective.

The project was begun in August with the final draft to be finished November 1, 2005.

---

[1] The California GHG target was announced by the Governor on June 1, 2005 and contained in Executive Order #2-3-05. For more information see: http://climatechange.ca.gov/.

[2] California Energy Commission and California Public Utilities Commission (2005): *Energy Action Plan II - Implementation Roadmap for Energy Policies;* California Energy Commission (2005): *2005 Integrated Energy Policy Report - Committee Draft Report* CEC-100-2005-007-CTD.

[3] For example, this report relies on research funded under the Public Interest Energy Research Program (PIER) and developed for the Integrated Energy Policy Report (IEPR).

Because of the very fast timeline and the primary reliance on existing information, this report should be viewed as a scoping document that provides a snapshot of the technical and economic feasibility of moving from a 20 to a 33 percent RPS target given the information available at this time. This report identifies a number of areas where additional in-depth analysis is recommended to better understand the dynamics of operating a supply system with 33 percent of its energy coming from new and emerging renewable technologies. Nevertheless, we believe the overall results reported here are valid, and though they will be refined over time as more specific analysis becomes available, we do not expect them to change substantially in either their underlying direction or in the magnitude of the impacts.

We want to particularly thank the staffs of both the CPUC and the California Energy Commission (CEC) for their cooperation in this effort. Much of the resource data was developed by the CEC in their Integrated Energy Policy Report (IEPR) process and was conveyed to us in real time as we conducted our analysis. Trying to conduct these two processes in parallel was challenging and could not have been accomplished without the generous cooperation of the CEC staff.

Table of Contents

LIST OF TABLES

LIST OF FIGURES

SUMMARY REPORT
ACHIEVING A 33% RENEWABLE ENERGY TARGET

In June 2005, Governor Schwarzenegger adopted greenhouse gas emissions reduction goals for the state of California. A centerpiece of his plan is to increase the state's goal for renewable resources to 33 percent by 2020 from the existing standard of 20 percent by 2010. The California Public Utilities Commission (CPUC) is charged with the implementation of these goals for the state's investor owned utilities, energy service providers and community choice aggregators.

an initial assessment of the steps needed to meet the 33 percent goal and preliminary answers to three questions: (1) Is there enough renewable energy resource potential to meet a 33 percent renewable energy goal at a reasonable cost; (2) what additions to transmission capacity and changes in transmission policy are needed to procure that level of renewables; and (3) what regulatory steps are needed to put California firmly on the path to achieving 33 percent renewables by 2020? This report should be looked upon as a preliminary scoping document that provides a snapshot of the technical and economic feasibility of moving from a 20 to a 33 percent renewable portfolio standard (RPS) given the information available at this time. There are a number of areas where additional in-depth analysis is recommended to better understand the dynamics of operating a supply system with 33 percent of its energy coming from new and emerging renewable technologies (see Section IX). Nevertheless, we believe the overall results reported here are valid, and though they will be refined over time as more specific data become available, we do not expect them to change substantially in either their underlying direction or in the relative magnitude of the impacts. [4]

GENERAL RESULTS OF THE ANALYSIS

It is economically and technologically feasible to achieve a 33% RPS in California by 2020. Moreover, a 33% RPS is likely to result in net savings to California's electricity customers over a twenty year period. Using the best information available at this time, a 33 percent RPS would result in a small negative ratepayer impact in the first decade (2011-2020). This is more than offset by longer term ratepayer benefits over ten years in the 2021 to 2030 timeframe. These estimates are meant to be indicative rather than absolute since, as this analysis demonstrates, there is considerable uncertainty surrounding future rate projections and RPS costs. The two variables that most affect the results of this analysis are the natural gas forecast and the estimate of renewable energy

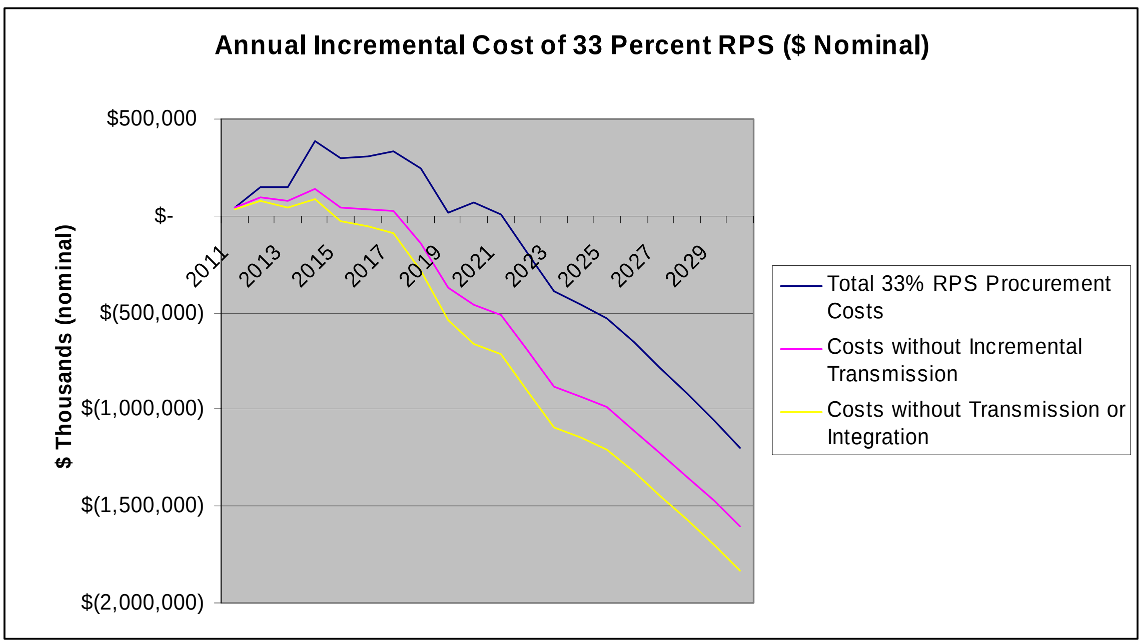
[4] / Following this summary report are supporting documents that contain greater detail on the analysis that was undertaken.

costs. Given the potential for future variability in these factors as well as transmission and greenhouse gas policies, it is important to adopt RPS policy mechanisms that allow the CPUC the flexibility to adapt to different future market scenarios as actual events unfold.[5]

Results of Cost Analysis [6]

The *33 Percent Renewables Base Case* analysis shows that the RPS will result in small average rate increases through 2021, and beyond that will produce long term rate savings. On a net present value basis (2011$, 9% discount rate), the RPS will increase costs to California IOU rate payers by $1.26 billion over the period 2011 to 2020, or roughly an average 0.57 percent rate increase over the period. However, these cost increases are offset by ratepayer savings that accrue in the years 2021 to 2030, after the initial capital investments of the RPS have been completed. The net present value of RPS rate payer impacts for the period 2011 to 2030 is - $175 million (2011$, 9% discount rate), in other words a net savings. The Figure 1 below summarizes the incremental cost impact of the RPS for IOU customers during the 2011 to 2030 timeframe for the 33 Percent Renewables Base Case.

Figure 1 - Annual Incremental Costs/Benefits of 33 Percent Renewables Base Case RPS Procurements



[5] / Although there is much uncertainty surrounding the development of a 25 year natural gas price forecast, we believe that the forecast used in this analysis is conservative. At the time this analysis was done, current natural gas NYMEX futures prices for the next year period range from $10-$14/MMBtu.[5] The natural gas price forecast used in this analysis does not reach a nominal price of $10/MMbtu until the year 2019, and does not reach $14/MMBtu until 2026.

[6] / A summary of the methodology used to develop these results is described in the Appendix to this Summary Report. A more detailed discussion of the methodology is covered in Section IV of the report.

Sensitivity Analysis

Sensitivity analysis was used to examine the affects of changes in natural gas prices as well as changes in renewable energy prices.[7] The results were as follows:

Natural Gas

The *33 Percent Renewables Base Case* scenario used the natural gas price forecast for electricity generators developed by the California Energy Commission as part of the 2005 Integrated Energy Policy Report. The recent run-up in natural gas prices (today at $12 to $14/MBTU in real 2005 prices) has brought into question all gas forecasts. However many of the underlying causes of today's high natural gas prices are tied to short-term issues of supply and demand that may or may not be reduced or mitigated over the next five years. This analysis focuses on 2011 to 2030 time period where it is assumed prices will have stabilized from today's supply/demand pressures and dropped somewhat due to the availability of liquefied natural gas (LNG) in the marketplace. This assumption about availability of low cost LNG supplies may be correct, however, as permitting and infrastructure development may not occur as fast as previously forecast, or at all if safety, security and financing obstacles are not resolved. Therefore, the natural gas price assumptions used in the *33 Percent Renewables Base Case* should be considered to be conservative.

Table 1 - Net Present Value of RPS Costs for California Ratepayers – Sensitivity Analysis (Negative number indicates rate reduction)

	10 year (2011-2020) NPV $million (2011$, 9% discount rate)	**2011-2020 Average Rate Impact**	**20 year (2011-2030) NPV $million (2011$, 9% discount rate)**
33 Percent RE Base Case	$1,264	0.57%	-$175
Gas Price 125% of *33 percent base case*	-$672	-0.42%	-$4,512
Gas Price 75% of *33 percent base case*	$3,200	1.77%	$4,162
High Renewables Costs	$3,517	1.75%	$4,188
Low Renewables Costs	-$230	-0.20%	-$3,068
PTC/ITC Continue	-$445	-0.26%	-$2,875

[7] / This analysis focused on the key variables associated with the RPS that could impact rates. There are many other variables that could impact rates significantly in this time period, such as regulatory treatment of existing utility owned generation, but such variables will create rate impacts regardless of the status of the RPS.

through 2015			
Transmission- 100% of incremental costs borne by RPS	$1,720	0.82%	$702
Transmission – 25% of incremental costs borne by RPS	$352	0.09%	-$1,929

As can be seen in Table 1, sensitivity analysis was undertaken using natural gas rates that are 25 percent higher and 25 percent lower than the 33 *Percent Renewables Base Case*. Under a scenario with 25 percent higher rates, the rate impact of the 33 percent renewable energy scenario would reach approximately $670 million net savings (NPV 2011 $, 9% discount rate) over the first ten years of the program and in excess of $4.5 billion in savings over twenty years. In a scenario where the natural gas rates are 25 percent lower than forecasted in the base case, the 33 percent renewable scenario would raise rates less than 2 percent over the years 2011 to 2020.

Cost of Renewables

The other variable with a high range of uncertainty is the cost of renewable energy facilities. Sensitivity analysis was done using prices that were, on average 28 percent higher and 15 percent lower for the renewable portfolio than were used in the *33 Percent Renewables Base Case.* Under the higher renewables price scenario, the rate impact was $2.25 billion higher in the first ten years than in the *33 Percent Renewables Base Case*. Using the lower renewable prices, there were ratepayer savings over the entire twenty year period of approximately $3 billion.

Natural Gas Rate Reductions

In addition to providing ratepayer and economic development benefits, as well as environmental improvements (particularly greenhouse gas reductions), a 33 percent California renewable energy scenario could result in lowering natural gas demand and concomitant reductions in natural gas prices for both residential and commercial gas customers. These savings could offset consumer RPS cost in the 2010-2020 time period.

We used simplified method developed by Lawrence Berkeley National Laboratory to evaluate the *incremental* impact of a "33 percent by 2020" California RPS on natural gas prices in California (relative to the 20 percent by 2010 target).

The net present value of the consumer natural gas bill savings from 2011-2020 (calculated in 2011, 9% nominal discount rate) amounts to just over $1 billion, while the net present value of gas bill savings from 2021-2030 (again calculated in 2011, 9% nominal discount rate) amounts to just under $1 billion. Over the entire period of interest, from 2011-2030, the net present value of gas bill savings in California consumers comes to roughly $2 billion.

Finally, it is worth reiterating that the Berkeley Lab "simplified method" employed above is intended to provide only a first-order approximation of the likely gas price and bill impacts. Considerable uncertainty remains. Specifically, the national equilibrium models used to calibrate the simplified method have not done a particularly good job of forecasting natural gas price movements historically, and are also often not geared towards regional or state-level analysis. A review of other studies employing more-disaggregated regional modeling capabilities suggests that, if anything, Berkeley Lab's simplified method could be conservative, and that the price and bill impacts reflected in Figure 2 could be even larger than shown.

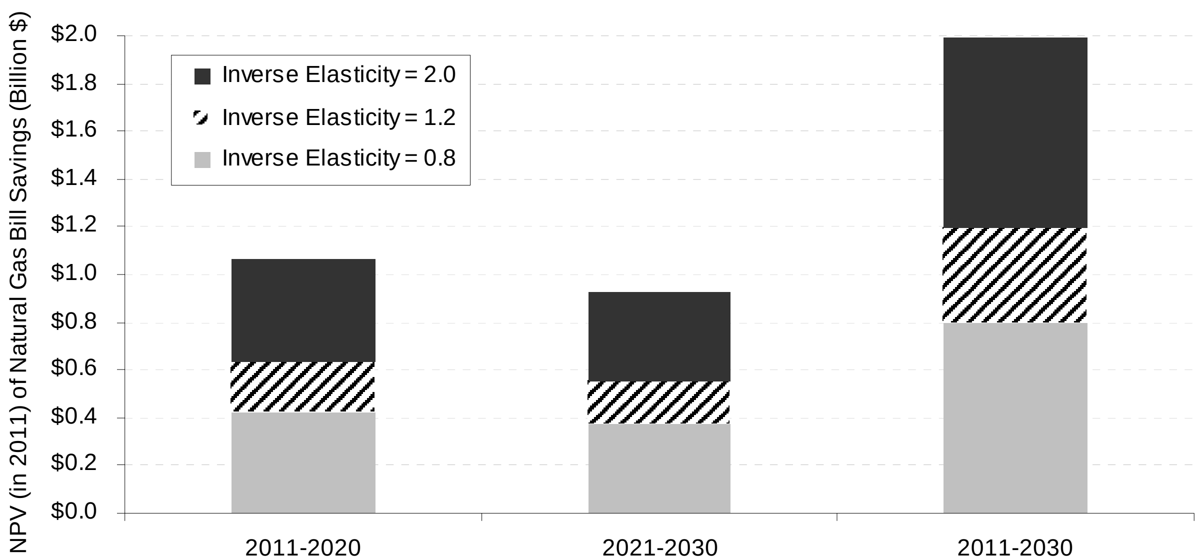


Figure 2 - Consumer Natural Gas Bill Savings Under a "33 percent by 2020" California RPS

Renewable Energy Supply[8]

While there are major concentrations of renewable energy in distinct geographic regions, these regions are reasonably well distributed around the state. With the development of transmission system upgrades and additions identified below, these renewable resources can be delivered to loads throughout California. While the projections of new renewable energy needs for a 33 percent RPS are quite large, they are well within the capacity development potential of California and neighboring state resources.

[8] / See Section II for more detail.

Table 2 - Comparison of Resource Needs and Developable Resource

Resource	Projected Resource Need	Identified Resource Available
Wind	7,600 MW	11,800 MW High Speed Sites 19,000 MW Low Speed Sites
Geothermal	1,800 MW	2,400 MW
Biomass	600 MW	1,500 MW
Solar	2700 MW	14,000 MW

Source: Tehachapi Study Group; Imperial Valley Study Group; CEC SVA and Hetchy-PIER

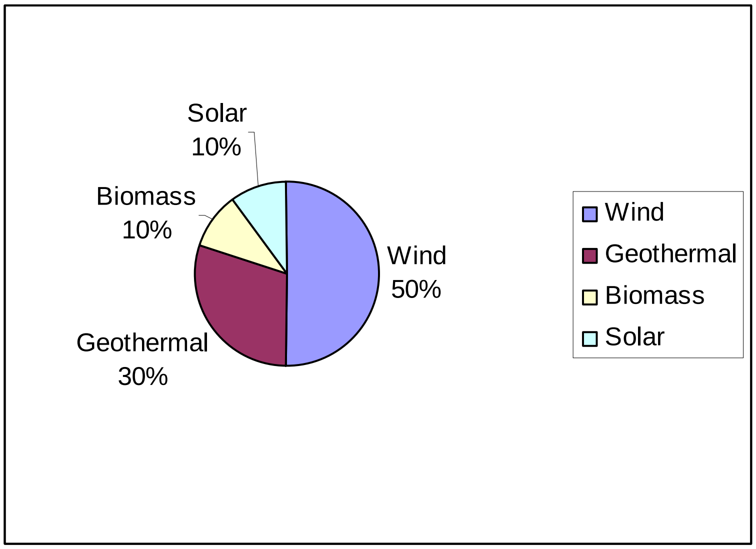


Figure 3 - Renewable Resource Portfolio Developed for this Analysis

Figure 3 shows the specific resource mix developed for use in this analysis based on the developable resources identified for the various technologies, the plausible transmission upgrades and additions during this period of time, and the economics and characteristics of each technology.

Transmission Resources[9]

Providing sufficient transmission capacity in a timely fashion is a formidable challenge for meeting a 33 percent renewables target. Transmission upgrade and expansion will be required across the state and region over the next two decades to accommodate load growth experienced over the past and current decade independent of an RPS. It is difficult to project a specific incremental transmission investment by the state that would be necessary to serve only an RPS need.

[9] / See Section II for more detail.

The primary transmission additions assumed to be needed to move from 20 to 33 percent RPS were taken from the series of utility, CEC and Study Group analysis conducted over the past two years. Projects beyond 2010 that appear to be focused on renewable energy supply have been identified as "33 percent RPS transmission projects." The costs of the transmission additions and system integration requirements needed for this level of renewable supply were added to the resource costs and are roughly half of the indicative rate increase mentioned Table 1 above (i.e. out of the 0.57 percent rate impact -- 0.28 percent is attributable to over market prices of renewable procurement and the other 0.29 percent is attributable to transmission and integration costs).

Conclusions of Cost and Rate Impact Analysis

Achieving a 33 percent RPS is shown to be possible with relatively small ratepayer impacts in the first decade of 2011-2020 (0.57 percent average overall rate increase) and longer term ratepayer benefits (NPV of $175 million in savings) in the 2011-2030 timeframe. The sensitivity analysis demonstrates that varying analysis assumptions, such as the level of future natural gas prices, the cost of renewables, and the burden of new transmission on the RPS, can have meaningful impacts on the overall costs of the RPS. However, the overall rate impacts of the variables addressed in the sensitivity analysis remain relatively small, and in none of the cases evaluated does the rate impact in the first 10 years exceed 2 percent.

Transmission Recommendations

Transmission System Operations Changes[10]

California is blessed with a rich set of renewable resources. However, with the exception of large hydro, much of the transmission system and the rules that govern its use were not designed with these resources in mind. Transmission's role in securing renewable resources is to first serve as a collector system from renewable generation plants and then a delivery system to move electrical energy to customers in population centers. Many of California's most important renewable resources are not found within the same areas as the oil and natural gas pipelines, and out-of-state coal resources that were the focus of the design for the collector portion of the system in the past. Often, renewable resources are distant from population centers and in areas that have limited electric transmission facilities. In general, rapid growth of renewable resources is occurring within a transmission system whose design, operating practices, tariffs, and market rules did not fully anticipate their increasing importance.

Accessing California's renewable resources to meet a 33 percent RPS will require expanding transmission capacity, increasing system operational flexibility, and changes to tariffs and rules governing use of the transmission system. Accomplishing this will need the coordinated efforts of the Federal Energy Regulatory Commission (FERC), the

[10] / For more detail see Section III.

California Public Utilities Commission (CPUC), the California Independent System Operator (ISO) and the California Energy Commission (CEC). The following table summarizes some of the key electric transmission actions to facilitate a 33 percent renewable portfolio standard and the agency(s) that could take action to address these issues. Different agencies have different jurisdictional options. Some issues may require action by all the agencies, while others may only require action by one agency depending upon what turns out to be the most feasible option. Following the table is a discussion of the key options.

Table 3 - Electric Transmission Actions for Facilitating a 33 Percent RPS[11]

		FERC	CAISO	CPUC	CEC
Expanding Transmission Capacity					
	Develop electric transmission capacity for renewables ahead of renewable generator interconnection requests.	✓	✓	✓	
	Adjust the transmission planning and expansion process to better reflect state policy for renewable resources.		✓	✓	✓
	Establish designated transmission corridors		✓	✓	✓
	Form additional stakeholder study groups for transmission projects in important renewable resource areas			✓	✓
	Reduce the risk associated with developing new transmission facilities	✓		✓	
Increasing System Operational Flexibility					
	Evaluate changes to operating practices for existing transmission and hydro assets		✓	✓	✓
	Evaluate whether a mixed portfolio of resource additions by area could reduce system integration costs		✓	✓	✓
	Encourage new transmission technologies that increase system operational flexibility		✓	✓	✓
Increasing the Receptiveness of Tariffs and Rules					
	Develop transmission rights and/or congestion revenue rights matched to renewable generator needs.	✓	✓		
	Ensure the compatibility of the California ISO's new market power mitigation rules with intermittent resources.	✓	✓	✓	✓
	Ensure fair and consistent capacity values for renewables within transmission market design and resource adequacy requirements		✓	✓	

[11] / For a more complete discussion see Section III -- Transmission.

Expand Transmission Capacity

Looking beyond 2010, growing renewable energy to 33 percent of California's resource mix will require concerted efforts to increase transmission capacity. Opportunities to increase the availability of transmission capacity for renewable energy could improve with policy changes addressing transmission interconnection, transmission planning, and transmission development. Probably the single biggest issue is developing a fair and equitable mechanism to finance grid upgrades for renewable resource areas where there are likely to be clusters of smaller renewable energy projects developed over time.

The CPUC recently opened an investigation (OII 05-09-006) in order to proactively take steps to ensure the development of adequate transmission infrastructure to access renewable resources for California. This proceeding will review structural and institutional barriers and address the issues identified in this report. It is expected that a decision will be issued in 2006.

Develop Electric Transmission Capacity for Renewables Ahead of Renewable Generator Interconnection Requests

FERC standard interconnection policies were developed primarily to accommodate central station generation projects that were frequently larger than renewable projects. Requiring generators to finance grid upgrades needed to deliver their energy to loads helps ensure that transmission capacity will not be built until it is necessary. However, requiring small renewable generators to finance network upgrades can inhibit implementation of state energy policy.

A clear solution for the issue is building transmission ahead of renewable generator interconnection requests. Probably the most viable funding approach is to establish rolled-in rate treatment for these facilities, paid for by all users of the California ISO grid. Southern California Edison filed a proposal with the Federal Energy Regulatory Commission (FERC) to create a new class of transmission dedicated to serving renewable resources for which the costs could be rolled into ratebase even if the line is not fully utilized. However, this proposal was rejected. The Transmission Section of this document contains other options that might be considered including the following.

- Allow transmission lines that are not designated as "network resources" to be placed in distribution system ratebase.
- Explore alternatives to SCE's proposal that may be more acceptable to the FERC.
- Create state funding support for the transmission facilities necessary to connect large concentrations of renewable resources through tax-exempt bond or loan guarantee programs.
- The California ISO could issue bonds to construct transmission projects for renewable energy identified in the ISO planning process.
- Hold transmission "open seasons" for renewable plant developers.

- Design transmission projects to explicitly qualify as “network upgrades” under FERC transmission expansion policy.

Each of these options has advantages and disadvantages that require study and discussion to identify the most feasible options and those with the greatest potential benefits to the citizens of California.

<u>Adjust the transmission planning and expansion process to better reflect state energy policy for renewables resources</u>

The California ISO recently proposed a new, proactive transmission planning process (August 2005) under which it would identify projects that should be built for economic or reliability reasons. Implementation of state energy policy has not been an objective in the California ISO planning process. It is important to align the ISO’s planning processes with the state’s renewables goals as well as economic and reliability objectives. Options to consider include the following.

- Adopt “support of state energy policy” as criteria for ISO transmission planning and expansion processes.
- Develop new options to help speed renewable energy projects through the transmission queue.
- Consider lengthening the conceptual transmission planning horizon.
- Develop predictive performance indicators of transmission expansion for renewables to assist State transmission decision-makers.

Increase Operational Flexibility

In every transmission system, some generators must be able to vary their generation output to follow daily and seasonal changes in demand or load. Transmission system operators need the operational flexibility to dispatch an appropriate amount of generation as load increases, or call upon generators to ramp down their production as load falls. Since electricity is not easily stored, the system operator must continuously balance generation with the load on the system in real time. However, system operators are finding they are increasingly losing operational flexibility. A growing proportion of thermal generators have little ability to be ramped up and down as needed.

The changing mix of thermal generation has resulted in continued reduction of operational flexibility of the grid at a time when it is needed to accommodate increased renewable generation. The limited predictability of intermittent generation can at times create uncertainty for system operators in arranging operating reserves, voltage regulation, and frequency control. Open access transmission tariffs based upon FERC Order 888 often include strong financial penalties for intermittent generation, discouraging the use of wind and solar resources in some parts of the country. However, suppressing the development of wind and solar generation was not the intent of this part of Order 888. The intent was to promote reliability. Future efforts to promote reliability may benefit from focusing on enhancing and maintaining operational flexibility. Getting more generators with load-following capability into the mix and adopting new grid operating practices could improve operational flexibility and help to achieve public policy for renewable resources.

Evaluate changes to operating practices for existing transmission and hydro assets.

Further evaluation of operating practices for existing transmission and hydro assets may result in mechanisms that can facilitate reaching a 33 percent RPS. These include:

- Investigating opportunities to better utilize California's hydropower, pumped storage, and demand side management potential to address intermittency issues.
- Investigating opportunities to increase the utilization of existing transmission infrastructure.

Increase the Receptiveness of Transmission Tariffs and Rules

California's transmission tariffs and market rules are more advanced than many states in accommodating renewable energy. For example, transmission access charges are levied on load-serving entities, not generators. The participating intermittent resource program provides a mechanism for renewable generators to avoid penalties for not being able to follow fixed generation schedules. Yet, there are still areas where changes may be needed to facilitate renewable generation.

The California ISO is planning a new market design based upon locational marginal pricing (LMP) for implementation in 2007. The market features will include a reliability-constrained economic dispatch, congestion management based upon economic principles, a spot market, a day-ahead market, a market for congestion revenue rights, and markets for ancillary services. New ways to price these rights could increase their usefulness to wind and solar generation. The following are two potential pricing options:

- Consider volumetric charges or other approaches to pricing congestion revenue rights that are not driven by capacity-based pricing.
- Develop new long-term versions of congestion revenue rights.

Ensure the Compatibility of the California ISO's New Market Rules with Intermittent Resources

The new market design in 2007 will play a key role in the viability of wind and solar resources in California well beyond 2010. This is a critical time to work with the California ISO to ensure that intermittent resources are not disadvantaged in the new market design.

Maintain the availability and benefits of the participating intermittent resource program (PIRP) in the new market design based upon locational marginal pricing (LMP).

Electric transmission will play a critical role in expanding the use of renewable resources in California. Removing unintended obstacles to developing new transmission capacity for renewable resources, increasing the operational flexibility of the grid to accommodate growth in renewable generation, and removing transmission tariff and non-tariff barriers to developing renewable resources are all three necessary to achieve a 33 percent renewable energy target.

Process and Policy Changes[12]

Developing a workplan for meeting a 33 percent renewables target is dependent first upon California's utilities meeting the current 20 percent RPS target. Based upon conversations with CPUC Commissioners and staff, a number of changes are already planned to improve and streamline the 20 percent RPS process. However, there are three critical actions that we believe should be taken right away that are important for meeting the 20 percent as well as a 33 percent RPS.

1. Clarify penalties for non-compliance. We would like to reinforce the need for the CPUC to clarify the specific conditions under which penalties would or would not be applied in order to help eliminate any uncertainty and misperceptions that presently exist. We see evidence of differences in perception between the CPUC and some stakeholders about the likely willingness of the CPUC to actually apply such penalties that undermines credibility and efficient actions by participants. We believe it is very important that the utilities and stakeholders believe the CPUC is serious about meeting the 20 percent RPS compliance deadline in 2010. Given that the highest forecasts of natural gas prices are for the 2005 to 2013 timeframe,[13] delay in the implementation of the 20 percent RPS could result in ratepayers paying billions of dollars in unnecessary costs associated with the operation of fossil plants necessary to replace the energy that would otherwise come from renewable facilities. For this reason alone it is imperative that the CPUC do everything possible to meet the 20 percent RPS as soon as possible.

2. Address potential contract failure. We strongly encourage the CPUC to anticipate and address this risk now, instead of addressing it after the fact by either imposing burdensome noncompliance penalties on utilities or essentially granting the utilities a "free-ride" and forgiving their lack of compliance. Addressing the issue in the near term will ensure that the state's utilities do not fall behind in achieving their renewable energy purchase requirements, an especially important goal if the procurement target is raised to 33 percent.

3. Open discussions with the FERC. Resolving the problems of expanding California's transmission grid in a manner that facilitates new renewables mandated by RPS legislation and CPUC policies must be a priority if the 20 percent RPS is to be met let alone a 33 percent target. Though the FERC turned down the SCE Trunk Line proposal, there may be other options for achieving the desired results that are acceptable to the FERC but have not yet been explored.

---

[12] / For more detail see Section V – Process and Policy Changes.
[13] / In the new CPUC gas forecast used for the MPR.

We believe opening a dialogue as soon as possible between the FERC and the CPUC, ISO and possibly the Governor's Office could lead to an important breakthrough in resolving this important transmission problem.

The recommendations presented in this section are informed by stakeholder views of the present RPS design as revealed by a recent CEC report (which focused on the 20 percent-by-2010 goal), CEC IEPR documents and filings, and the Energy Action Plan II. To be clear, our focus is not on identifying near-term actions that are necessary to achieve a 20 percent renewable energy target, but instead on highlighting actions that may be critical to achieving the 33 percent goal. Nonetheless, in part based on conversations with CPUC staff and as shown in Table 3, we believe that at least some of these recommendations are likely to be addressed in order to meet the 20 percent goal.

We also recognize that many of the recommendations summarized in Table 5 and discussed in the text that follows would require legislative change. New legislation is necessary if the state is to be sure of achieving a 33 percent goal; existing CPUC jurisdiction may allow the state to exceed a 20 percent target, but cannot assure achievement of 33 percent goal. We therefore identify those recommendations that would likely require legislative action, as distinguished from those that appear possible under current law.

Table 4 -- Preliminary Policy Actions for Achieving a More Aggressive RPS

Recommended Actions[14]	Assumed to Be Implemented for 20 % Target*	Necessary for 33 % Target	New Legislation Needed
Firmly Establish the 33 % Target in Legislation			
Codify 33 % target for the state's IOUs, ESPs, and POUs		✔	✔
Incorporate legislative or regulatory flexibility to alter 33 % target		✔	✔
Better integrate renewables into general procurement planning	✔	✔	
Regulatory Process Changes			
Augment staffing and provide consistent focus on RPS	✔	✔	
Continuously prioritize items most critical to target achievement	✔	✔	
Increase transparency of certain information		Consider	**?**
Develop an RPS that Works for ESPs and CCAs			
Provide procurement flexibility to ESPs/CCAs	✔	✔	**?**
Develop central procurement agent for ESPs/CCAs		Consider	**?**
Speed and Streamline the Solicitation Cycle			
Streamline the current regulatory requirements and processes	✔	✔	
Allow less frequent but larger formal RPS solicitations, with greater allowance for bilateral contracts		Consider	
Establish RFO-cycle deadlines for IOUs		Consider	
Further standardize contracts, and RFO requirements	✔	Consider	
Other measures (see text)		Consider	**?**

[14] / Many other items might also be useful to address in the achievement of the 20 % goal; here we identify only those that we believe are very likely to be addressed by the CPUC under current statutory authority.

Recommended Actions[14]	**Assumed to Be Implemented for 20 % Target***	**Necessary for 33 % Target**	**New Legislation Needed**
Address Contract Failure			
Encourage over-contracting by clarifying the application of penalties and flexibility mechanisms	✔	✔	
Evaluate how bid deposits, credit requirements, and bid evaluation protocols can minimize the risk of contract failure	✔	✔	
Require over-contracting for renewable energy		Consider	
Provide Delivery Flexibility, and Allow Unbundled RECs			
Allow shaped products if energy delivered to state	✔	✔	
Allow generator delivery to out-of-state hubs, with purchaser delivery into state		✔	**?**
Standardize evaluation of projects with out-of-territory delivery		Consider	
Allow in-state unbundled RECs, possibly with restrictions		Consider	**?**
Allow out-of-state unbundled RECs, possibly with restrictions		Consider	✔
Consider applying SEPs to RECs		Consider	✔
Develop Appropriate Mix of Carrots and Sticks			
Regulatory vigilance and application of current penalties	✔	✔	
Clarify or revise system of penalties and flexibility mechanisms		Consider	
Additional procurement flexibility if new transmission expected for major renewable additions		Consider	**?**
Utility profit incentives for renewables procurement		Consider	
Eliminate MPR-SEP Structure		Consider	✔

The most important actions that need to be taken in order to achieve a 33 Percent RPS and more fully discussed in Section V are the following:

Firmly Establish the 33 Percent Target in Legislation -- New legislation codifying the 33 percent renewable energy target is necessary if the state is to be assured of achieving this aggressive goal. New legislation is crucial if the more aggressive target is to apply on a *statewide* basis, covering not only CPUC-jurisdictional IOUs, ESPs, and CCAs, but also the state's publicly owned utilities. Though some additional flexibility might be warranted for the state's smallest electric utilities, achieving a *statewide* renewable energy target will require *statewide* application of the purchase requirement. A broader application of the policy to all of the state's electricity providers may also ease concerns about unequal cost burdens.

Regulatory Process Changes -- The regulatory obligations imposed on the CPUC and the CEC are substantial, and should be matched with a sizable, professional staff dedicated to renewable energy issues within each of these state agencies. Currently, the CPUC faces a critical shortage in positions and it is essential to the achievement of the 33 percent target to add staffing to oversee and implement the programs. Moreover, given these regulatory demands, it is essential for the state's energy agencies to continuously prioritize the regulatory issues that are most critical to the achievement of the state's renewable energy goals. Less significant issues can and should be left for future decisions.

Develop an RPS that Works for the State's ESPs and CCAs -- The CPUC is presently working to develop an overall compliance framework for the state's ESPs and CCAs, and we assume that (despite the complexity) these issues will be largely resolved prior to achieving the 20 percent RPS. Specifically, we assume that some degree of procurement flexibility will be offered to the state's ESPs and CCAs, which could include some variances. We understand that each of these "variances" has advantages and drawbacks, and that hard tradeoffs may be required. As a result, each of these measures may need to be conditioned on certain other requirements as the RPS rules progress.

Speed and Streamline the Solicitation Cycle -- Achieving a 33 percent renewable energy target will require frequent and sizable renewable energy solicitations. Even to achieve the 20 percent RPS, some streamlining of the solicitation cycle is necessary. We understand that the CPUC plans to tighten the solicitation cycle in future years by, for example, simplifying, speeding, and consolidating regulatory processes, filings, and decisions, and by incorporating long-term renewable energy procurement plans within the general procurement plans of the IOUs. We further assume that the state's electricity suppliers will learn to more rapidly proceed with their solicitations in order to achieve the 20 percent goal, building off of experiences gained in the first set of RFOs. We are hopeful that the above actions will be all that is needed to speed and streamline the solicitation cycle. If these changes prove insufficient, however, the CPUC may want to consider less frequent but larger RFOs. Alternatively, the CPUC might consider establishing deadlines by which utilities must submit contracts under each RFO, or further standardizing procurement practices and contract terms and conditions to minimize the time consuming process of negotiating with short-listed bidders.

Address Contract Failure -- An emerging concern in California and other states is that of contract failure: the nearly inevitable situation in which signed contracts with renewable projects do not *all* yield operating facilities on the schedule originally envisioned. We strongly encourage the CPUC to anticipate and address this risk now, instead of addressing it after the fact by either imposing burdensome noncompliance penalties on utilities or essentially granting the utilities a "free-ride" and forgiving their lack of compliance. Addressing the issue in the near term will ensure that the state's utilities do not fall behind in achieving their renewable energy purchase requirements, an especially important goal if the procurement target is raised to 33 percent. We recommend that the CPUC provide up-front guidance on the *specific* conditions that would have to be met for penalties to be waived in the event of contract failure. We further expect and recommend that the CPUC will continue to evaluate how bid deposits, credit requirements, and bid evaluation protocols might be used to minimize the risk of contract failure, while at the same time not overly limiting the number of project bidders. Finally, the CPUC should consider *requiring* utilities to "over-procure" renewable energy by a specific margin, in anticipation of some level of contract failure.

Provide Delivery Flexibility, and Allow Unbundled Renewable Energy Certificates (RECs) -- California's renewable energy delivery requirements were recently modified to allow for a broader range of delivery locations. This change is encouraging, but additional modifications should be considered to further promote supply competition, *especially* if a more aggressive 33 percent target is implemented. With an aggressive 33 percent target, we also believe that it may ultimately be necessary to provide additional delivery flexibility to out-of-state generators by permitting the use of unbundled RECs from outside the state. This may be especially the case in the event that resource, permitting, or transmission constraints hinder in-state development. In so doing, however, the state will lose at least some of the "in-state" benefits of renewable energy development such as the hedge benefits renewables can provide against natural gas price volatility.[15] On the other hand, allowing greater competition from out-of-state renewables can exert downward pressure on renewable prices.

Develop an Appropriate Mix of Incentives and Penalties -- The CPUC has already developed a set of penalties and flexibility mechanisms that apply to utility RPS compliance obligations. We recommend that the PUC continue to be vigilant, and willing to apply penalties in cases of clear non-compliance. The Commission should send clear signals to this effect to utilities at every opportunity. At the same time we also see evidence of significant differences in perception between the CPUC and many stakeholders concerning the willingness of the CPUC to actually apply such penalties. Clarification of the specific conditions under which penalties would or would not be applied would help to reduce some of the uncertainty and misperceptions that presently exist. Given that the highest forecasts of natural gas prices are for the 2005 to 2010 timeframe, delay in the implementation of the 20 percent RPS could result in ratepayers paying billions of dollars in unnecessary costs associated with the operation of fossil plants necessary to replace the energy that would otherwise come from renewable facilities. For this reason alone it is imperative that the CPUC do everything possible to meet the 20 percent RPS as soon as possible.

Eliminate MPR-SEP Structure -- As the state seeks to achieve a more aggressive 33 percent RPS, we recommend that the legislature consider the elimination of the present MPR-SEP structure. Such a change would clearly require legislation, and should in no instance jeopardize current utility procurement activities conducted to achieve the 20 percent requirement. SEPs can create perverse incentives. The existence of the MPR-SEP structure: (1) may negatively affect bid prices and thereby inflate the cost of the RPS to the state's electricity ratepayers; (2) leads to questions over the certainty and financeability of state-administered SEPs to renewable generators; (3) complicates the issue of unbundled RECs (specifically, whether such transactions can receive SEPs); and (4) creates potential coordination challenges between the CPUC and CEC. While each of these concerns can be addressed, to some degree, we question the fundamental value of the MPR-SEP construct, especially in an era of high natural gas prices where renewable energy contracts appear cost effective. The primary stated advantage of the current MPR-SEP structure – the establishment of a cap on overall program costs – can easily be accommodated through other means (many other states, for example, have developed

[15] / Though this can be mitigated through the use of Contracts for Differences.

cost caps without a MPR-SEP structure). To avoid interruption of a program that is beginning to show signs of working, we recommend that the state legislature revisit the MPR-SEP structure during deliberations on a 33 percent RPS. We also recommend that should such a change be made, the present system remain in place until the new system is fully operational, and that all care is made to ensure a seamless transition.[16]

Other Renewable Benefits

Greater overall system flexibility can result if the California electricity grid is reconfigured over time with operationally flexible natural gas units to better integrate renewables. The in-state renewables are likely to displace natural gas imports and electricity production from out of state fossil generation resulting in a net gain in employment, landowner lease income and local and state tax revenues. While we have not quantified these benefits they are valuable attributes of a 33 percent RPS policy. Even with the loosening of the deliverability requirements and allowing out-of-state unbundled RECs, we believe the majority of the renewable energy supply will come from in-state renewables that will deliver substantial benefits to the citizens of California.

Distributed Photovoltaics and the Voluntary Renewables Market[17]

<u>Distributed PV:</u> Based on our analysis, it is possible for California to achieve 3 to 6 percent of its electricity supply from distributed renewable generation (primarily from photovoltaic --PV installations) during the 2010 to 2020 timeframe. Some portion of this could be incorporated into the RPS target, although we have not done so in our analysis. We have heard some discussion of a production-based PV incentive program in which the renewable certificates produced by these facilities would go to the local utility for RPS compliance purposes. Another option favored by the PV industry is to create a PV/DG carve-out in the 33 percent RPS or as an addition to the 33 percent RPS that would support the development of additional solar supply. Either of these is a possible option.

PV offers a range of valuable public benefits even though it is not currently cost competitive with retail electricity rates. It can be installed without need for transmission investment, avoids line losses associated with central station generation, adds to diversity of the generation system and is often correlated with peak load (avoiding the highest cost fossil peak generation and reducing a wide range of pollution associated with fossil generation including greenhouse gas emissions).

According to the PV experts interviewed for this report, PV is expected to be *cost competitive with retail electricity rates* within ten to twelve years. Drivers for cost reduction include incremental improvements in the technology, manufacturing and

---

[16] If the present MPR-SEP structure is maintained to achieve a 33 percent target, it may be necessary to increase the funding pool for the SEP payments.
[17] / For more detail see Section IV.

installation scale-up, and the potential for a major technology breakthrough. Evidence of industry confidence in that timeframe is found in the industry's support for a declining rebate program like that proposed by the Governor's Million Solar Roofs Initiative and research by third parties.[18] Escalating fossil fuel prices, leading to higher retail electricity prices are also expected to close the gap between retail electricity rates and the cost to the consumer of installing PV. Moreover, PV offers a useful "hedge" against not only fossil fuel price increases, but also more stringent future environmental regulations that could increase the cost of electricity from the grid where that is supplied by fossil plants.

Recommendations

Maintain Stable DG Support

Over the next five years, develop and maintain stable state support for DG/PV (e.g. help keep PV growth at ~30 percent) in order to maximize the amount of cost-effective PV available 2010 to 2020.

Maintain Net Metering

Maintain the existing net-metering program to support a stable market environment. Adjust the program and the use of a program cap as appropriate to changing circumstances.

Implement PV Tariff

Develop a state-wide PV tariff (analogous to the PG&E A-6 tariff) that is based on the value of the time of delivery) that can supplement or replace the present tariff structure. There could also be a regulatory reward side for IOUs that develop innovative programs that take advantage of DG/PV to reduce system costs of transmission and distribution grid operation while stimulating greater use of PV.

Inter-agency Working Group

Include the PV industry in the inter-agency working group for self-generation.

Clear Rules for DG Customers[19]

Continue to allow customers with DG to have clear property rights to renewable energy certificates unless they explicitly deed them through contracts to another party. This will allow customers with distributed generation systems in the future to

[18] / Maya Chaudhari, Lisa Frantzis, Tom Hoff; "*PV Grid Connected Market Potential under a Cost Breakthrough Scenario*, "The Energy Foundation, September 2004. Marvin S. Keshner, Rajeeswa Arya; "*Study of Potential Cost Reductions Resulting from Super-Large-Scale Manufacturing of PV Modules.*" NREL, October 2004.

[19] / Though the CPUC attempted to clarify this position in D.05-05-011, May 5, 2005, there unfortunately remains a significant disagreement and confusion concerning what the decision actually meant.

make informed choices regarding the disposition of the renewable energy certificates (REC) from their systems under various incentive scenarios. This clarification will also provide present owners of DG systems a clear understanding of the market choices available to them without the risk that they have misinterpreted the CPUC rules.

Aggregated DG RPS Priority or Alternative DG/RPS Target

Consider giving priority to aggregated power from distributed generation in one or more of the utility RPS solicitations or, as an alternative, establish a separate DG/RPS carve out.

Voluntary Market: Voluntary renewable markets are only eight years old, but experience to date demonstrates their promise in supporting substantial renewable development. Initially, voluntary renewable energy markets were limited to states that allowed direct access (i.e. restructured states) and to utility green pricing programs. With the advent of RECs, voluntary renewable energy markets are growing rapidly in many regions, and are expected to be a larger driver for new renewable energy additions in the future. These markets have increased by 1000 percent in the past five years, and we expect them to continue to increase by 50 to 60 percent each year in the near future. In 2004, national voluntary renewable markets resulted in more than 2200 MW of new renewable capacity.[20]

Even with a 33 percent renewable energy target, there are electricity customers who would be willing to pay extra, if necessary, to go beyond that target (the City of Palo Alto's green pricing program currently has 13 percent residential enrollment). Add to that the value of renewables if offered as a hedge against volatile natural gas prices, and financing options for PV/DG, and Green Pricing Programs could become very popular in California. It is possible that if California's investor owned electric utilities offered well designed Green Pricing programs or Green Tariffs this could add 1 to 3 percent additional renewable sales above the state RPS mandate.

In looking at data from the national voluntary market, we believe another 1.5 percent renewables could be produced from green pricing program sales. Though no investor owned utilities in California presently offer green pricing programs, several municipal utilities in California and elsewhere have had significant success with green pricing (e.g. Sacramento, Palo Alto, and Austin, Texas.).

In total, 6 percent of additional renewable energy from the voluntary market could be added to the 33 percent renewable energy target. From our analysis it appears renewable resources in the western states are adequate to supply both the voluntary as well as the compliance markets. This means with leadership and political will, California could reach 39 percent renewable penetration by 2020. There are many caveats that go along with

---

[20] / *Green Power Marketing in the United States: A Status Report.* Lori Bird & Blair Swezey, NREL/TP-620-38994, October 2005.

these projections of voluntary market contributions, but they are possible to achieve under the right circumstances.

Recommendations

Carbon Benefits for Renewable Generators

Support voluntary renewable energy markets by ensuring that renewable energy generators are able to pass along the carbon benefits associated with their power generation to their customers. This includes ensuring renewable energy and RECs from projects located in other states but sold into the California market are able to transfer their carbon benefits to the California purchaser.

Additionality of Voluntary Market

Ensure renewable energy sold in voluntary markets is additional, accounted for separately and not counted toward compliance with mandatory targets.

Green Pricing

Encourage or require State IOUs to offer green pricing/tariff programs that incorporate best practices:

a. Are based on new renewable generation facilities;
b. Are additional to utility mandates;
c. Allow customers to hedge against fuel price fluctuations;
d. Allow the use of regional RECs as appropriate;
e. Encourage the use of contracts for differences for RECs; and
f. Keep any above market prices consistent with actual renewable energy costs and only include reasonable fees for services

ROADMAP FOR THIS REPORT

Following this summary is a series of supporting documents from which this summary was derived. Section I describes the status and structure of the current CPUC renewable portfolio standard (RPS) program. Section II summarizes the technical information on existing and potential renewable sources, as well as characterizing existing and potential transmission sources and integration strategies required to assimilate 33 percent renewable energy into the California grid. Section III describes transmission and system operation modifications necessary to support additional renewables under current deliverability rules. Section IV presents the rate impact of various 33 percent scenarios. Section V examines the changes that might be necessary to meet an expanded scope of work for a 33 percent goal. Section VI characterizes the distributed generation and voluntary market sectors that might provide additional renewable capacity above what would be provided by a 33 percent RPS. Section VII discusses how a 33 percent RPS program can be integrated with the State’s greenhouse reduction target and related programs. Based on the results from the analysis presented in previous chapters, Section

VIII provides recommendations for a CPUC workplan and schedule for achieving the 33 percent goal based on the most feasible rate scenario. Finally, Section IX contains recommendations for further study.

APPENDIX A

METHODOLOGY FOR COST AND RATE IMPACT ANALYSIS

The incremental costs of the 33 percent RPS are calculated by comparing the projected procurement costs of the RPS, including any incremental transmission and wind integration costs (the *33 Percent Renewable Base Case Scenario*), to a projection of the otherwise applicable costs the IOUs would incur to purchase the same amount of energy at market prices. These otherwise applicable costs are characterized in a business as usual (BAU) scenario that assumes that the current 20 percent RPS is achieved by 2010, and that energy procurements that would have been provided by 21-33 percent RPS procurements are replaced with generation resources purchased at market prices. The differential between these two cost projections is the cost impact of the 33 percent RPS. Rate impacts are calculated by developing a long term projection of retail rates without the 33 percent RPS (including only a 20 percent RPS), multiplying these rates by a load forecast to derive total revenues collected by rates, and then dividing the cost impact of the 33 percent RPS by this total.

Total RPS cost = Total Delivered Energy Cost of RPS Renewables – Otherwise Applicable Cost of Market Procurements

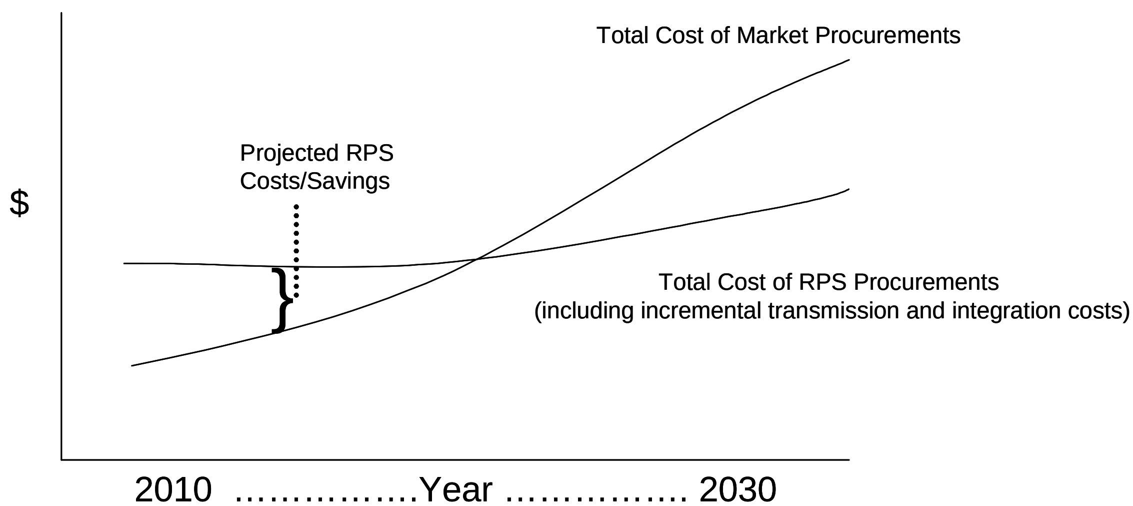


Figure 4 Analytic Approach-Comparing RPS Costs with Market Procurements

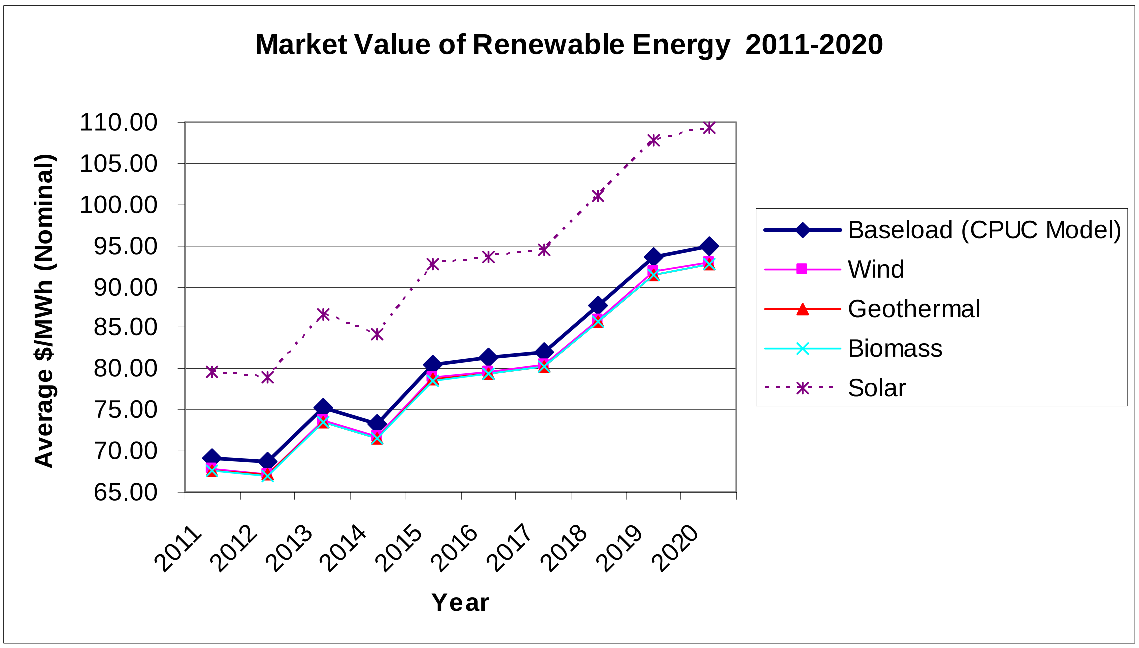
Price Forecast: The forecast of electricity market prices in each year was developed using the methodology adopted by the CPUC to calculate avoided costs.[21] This

[21] CPUC D.05-04-024, April 7, 2005. This decision adopted a report by Energy and Environmental Economics (E3), entitled Methodology and Forecast of Long-Term Avoided Cost(s) for the Evaluation of California Energy Efficiency Programs (Final Report). The worksheets implementing this methodology can be downloaded at: http://ethree.com/cpuc_avoidedcosts.html.

methodology assumes that market prices in the post 2010 time frame will be equal to the cost of electricity produced by a new natural gas combine cycle combustion turbine. This method of forecasting market prices is highly dependent upon the natural gas price forecast that is an input into the CPUC methodology.

Natural Gas Price Forecast: For this analysis, the natural gas price forecast was updated from what was used earlier this year by the CPUC to reflect the most recent natural gas price forecast available for California generators. This is the natural gas price forecast developed for the 2005 CEC IEPR proceeding (see Market Price Forecast Section of Appendix IV-A).

Figure 5 Market Value of Renewable Energy (2011-2020)



Market Prices: The CPUC methodology used to calculate market prices includes a function to develop market prices by time of delivery (TOD). This analysis used the TOD factors in the CPUC methodology to develop market price forecasts that fit the production profiles of each of the renewable resource types assumed for the 33 percent RPS case. The market price forecasts represent the market value of the renewable energy sources purchased for the RPS, and the analysis assumes that the utilities will pay these prices for market energy in the BAU scenario. Figure 5 above illustrates the resulting market price forecasts for each renewable energy technology (see Appendix IV-A for a description of the TOD assumptions).

Load Forecast: For the purpose of calculating the RPS procurement requirements for the IOUs in this analysis, we base the RPS procurements on a load forecast strictly for IOU loads. This load forecast was developed by taking estimates of current IOUs loads

(190,080 GWh in 2006), and escalating them at 2 percent per year through the analysis period.

Renewable Costs: This analysis assumes that the contracted price of renewables is equal to the price projections shown in Table 6 below. In addition to the renewable energy procurement costs, integrations costs associated with the use of intermittent wind energy are added to the projection of RPS costs. Finally, the costs of incremental transmission investments for the RPS renewables facilities in California were also added to the renewables cost projection.[22]

Table 6 -- 33 Percent Renewables Base Case Incremental Energy Price- No PTC or ITC

Resource	$/MWh (nominal)
Wind	$66
Geothermal	$86
Biomass	$78
Solar	$120
PV	$200

Rate Impact

The sections above describe the inputs used to develop the total net revenue impact of the RPS. To evaluate the average statewide rate impact, the analysis divided the total net revenue impact of the RPS procurement in each year by the total revenue requirement of the three IOUs. Total utility revenue requirement was developed by developing a projection of the average IOU rate for the analysis period, and multiplying that rate by a load forecast. The load forecast assumed 2006 IOU load was 190,080 GWh, and would grow at 2 percent per year. We developed rate forecasts for PG&E and SCE for the analysis period, and assumed that the statewide average IOU rate would be equal to the load weighted average for these two utilities. The statewide average utility rates are reproduced below.

Table 7 – Projection of Average IOU Rates

Year	IOU Average $/kWh
2006	0.1252
2007	0.1248
2008	0.1172
2009	0.1300
2010	0.1240
2011	0.1339
2012	0.1339

[22] / In developing the forecast of utility rates without the 33 percent RPS, we considered current and historical utility transmission costs, and do not include any extra incremental transmission costs for new transmission to deliver non-renewable electricity from the interior-West.

Year	IOU Average $/kWh
2013	0.1412
2014	0.1393
2015	0.1474
2016	0.1497
2017	0.1527
2018	0.1590
2019	0.1694
2020	0.1718

CURRENT STATUS AND STRUCTURE OF THE CALIFORNIA RENEWABLES PORTFOLIO STANDARD (RPS)[23]

Overview of the California RPS

In 2002, California enacted an aggressive renewables portfolio standard (RPS) that calls for the state's investor-owned utilities (IOUs), energy service providers (ESPs), and community choice aggregators (CCAs) to meet 20 percent of their electricity load with eligible sources of renewable energy by 2017.[24] The state's *Energy Action Plan*,[25] the California Energy Commission's (CEC) *Integrated Energy Policy Report*,[26] and various rulings from the California Public Utilities Commission (CPUC)[27] have committed to an acceleration of the RPS such that the 20 percent goal is met seven years early, by 2010. Governor Schwarzenegger has endorsed this accelerated schedule and has set a goal of achieving a 33 percent renewable energy share by 2020 for the state as a whole; the state's *Energy Action Plan II* identifies required actions to achieve this goal.[28]

Under SB 1078, the state's investor owned utilities (IOU), energy service providers (ESP) and community choice aggregators (CCA) are required to increase by at least 1 percent annually the percentage of their load served by eligible sources of renewable energy. For the IOUs, this is accomplished through annual solicitations for renewable energy generation and, to a lesser extent, through bilaterally negotiated contracts. Publicly owned utilities (POUs) in the state are required to develop their own RPS policies, but are given flexibility in how those policies are designed and implemented.

---

[23] This section is based to some degree on Wiser, Ryan, Kevin Porter and Mark Bolinger. "Preliminary Stakeholder Evaluation of the California Renewables Portfolio Standard." CEC-300-2005-011, June 2005. http://www.energy.ca.gov/2005publications/CEC-300-2005-011/CEC-300-2005-011.PDF; and on a derivative journal article, Wiser, Ryan, Kevin Porter, Mark Bolinger and Heather Raitt. "Does It Have To Be This Hard: Implementing the Nation's Most Complex Renewables Portfolio Standard." *The Electricity Journal*, 18(8), 55-67.

[24] SB 1078, Chapter 516, Statutes of 2002, Sher. See: http://www.dsireusa.org/documents/Incentives/CA25R.pdf

[25] California Energy Commission, California Public Utilities Commission, Consumer Power and Conservation Financing Authority. "Energy Action Plan." May 2003. http://www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF.

[26] California Energy Commission. "2004 Energy Report Update." CEC-100-04-006CM, November 2004. http://www.energy.ca.gov/reports/CEC-100-2004-006/CEC-100-2004-006CMF.PDF.

[27] See, for example, California Public Utilities Commission, "Opinion Approving Procurement Plans and Requests for Offers for 2005 RPS Solicitations." Decision 05-07-039, July 7, 2005.

[28] California Public Utilities Commission and California Energy Commission. "Energy Action Plan II: Implementation Roadmap for Energy Policies." October 2005. http://www.cpuc.ca.gov/word_pdf/REPORT/50480.pdf.

The CEC has estimated that meeting 20 percent of the *state's* electrical load with eligible sources of renewable energy by 2010 would require the addition of approximately 6,900 MW of new renewable generating capacity, including 3,900 MW to serve the state's IOUs and 3,000 MW to meet the needs of ESPs, CCAs, and POUs.[29] This makes California's 20% RPS the most ambitious state RPS in the nation in terms of potential capacity additions

California is one of twenty-one states that have established RPS requirements, and the statutory design of the California RPS is unique.[30] Under SB 1078, payments by load serving entities (LSEs) for renewable energy are capped at a market price referent (MPR -- currently reflecting the estimated all-in cost of baseload and peaking gas-fired generation), with any costs above the MPR covered by supplemental energy payments (SEPs) from the state's renewable energy fund, administered by the CEC. In addition, the California RPS statute requires the state's IOUs to use a "least cost, best fit" (LCBF) process for bid evaluation[31], and the CPUC requires the IOUs to incorporate CPUC-approved bid-evaluation protocols, integration cost estimates, and qualitative evaluation factors into their bid evaluation processes. To satisfy legislative requirements that utilities consider transmission costs in evaluating bids, the CPUC also requires the IOUs to develop transmission ranking cost reports (TRCR) that estimate the cost of transmission expansion needed to access potential renewable energy projects and that are used in bid selection. The CPUC has developed a limited set of standard contract terms and conditions for use by the state's IOUs in procuring renewable energy. To help oversee procurement decisions, the CPUC has established procurement review groups (PRG). The PRGs consist of non-market participants who review and provide input during the utility renewable solicitation process, under nondisclosure restrictions. Under current regulations, obligated LSEs must procure renewable electricity to satisfy their RPS obligations; use of unbundled renewable energy certificates (RECs) is not allowed.

SB 1078 calls for the CPUC and CEC to work collaboratively to implement the RPS, and assigns specific roles to each agency. Pursuant to SB 1078, the CPUC is charged with: (1) determining the MPR; (2) establishing the process by which LSEs will select renewable resources on a LCBF basis; (3) implementing flexible rules for compliance with annual procurement targets, and establishing penalties for lack of compliance; and (4) establishing standard terms and conditions to be used in contracting for eligible renewable energy resources. The CPUC also oversees the utilities' short- and long-term renewable energy plans, establishes compliance schedules, and oversees renewable

---

[29] An average capacity factor of 50 percent is assumed by the CEC. California Energy Commission. "Implementing California's Loading Order for Electricity Resources." CEC-400-2005-043, July 2005. http://www.energy.ca.gov/2005publications/CEC-400-2005-043/CEC-400-2005-043.PDF.

[30] For an overview of RPS design and experience in other jurisdictions, see: Wiser, Ryan, Kevin Porter and Robert Grace. "Evaluating Experience with Renewables Portfolio Standards in the United States." LBNL-54439, March 2004. http://eetd.lbl.gov/ea/ems/reports/54439.pdf; and, van der Linden, Nico, et al. "Review of International Experience with Renewable Energy Obligation Support Mechanisms." ECN-C—05-025, May 2005. http://eetd.lbl.gov/ea/ems/reports/57666.pdf.

[31] Flexibility is provided to utilities in their least-cost, best-fit evaluation processes, but in all cases the LCBF process intends to identify those project bids that have the best mix of low cost and reasonable fit with utility procurement needs.

energy solicitations. The CEC must: (1) certify eligible renewable resources; (2) design and implement a renewable energy tracking and verification system; and (3) allocate and award SEPs to eligible renewable projects to cover contract costs that exceed the MPR.

Renewable Energy Procurements and Procurement Plans

Much has already been accomplished under the state's RPS. Regulatory rules implementing major portions of the statute have been completed by the California Public Utilities Commission and the California Energy Commission.[32] As a result, the state's IOUs are now actively pursuing renewable energy supply.

Through interim renewable energy solicitations issued in 2002 and 2003, bilateral contracts, and more recent formal RPS solicitations, the state's three major IOUs have increased their purchases of renewable energy from approximately 19,190 GWh in 2002 to an expected 23,110 GWh in 2005 (see Figure 1). In 2004, 13.9 percent of the load of the three major IOUs was met with renewable energy purchases, up from 12.5 percent in 2002. As a percentage of 2004 utility load, from 2002 to 2005, Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) expect to increase their renewable energy purchases by approximately 2.2 percent, 2.1 percent and 4.7 percent, respectively.[33]

[32] On June 19, 2003, the CPUC made threshold decisions on the basic structure and application of the RPS; laid out the general approach to be used for utility solicitations; and set compliance schedules, flexibility mechanisms, and penalties for noncompliance (D.03-06-071). On June 9, 2004, the CPUC established its methodology for establishing market price referents (MPRs) (D.04-06-015), adopted standard contract terms and conditions that govern power purchase agreements signed under the state's RPS (D.04-06-014), and established methods for ranking bids based on their expected transmission costs, using "transmission ranking cost reports" (TRCRs) (D.04-06-013). On July 8, 2004, the CPUC defined the approach to evaluating bids under a least-cost, best-fit (LCBF) framework (D.04-07-029). On May 5, 2005, the CPUC clarified the participation of renewable distributed generation under the state's RPS (D. 05-05-011). On July 21, 2005, the CPUC revised its TRCR requirements for the 2005 solicitation cycle (D. 05-07-040), and approved (with modifications) the utilities' 2005 short-term renewable energy procurement plans and solicitations (D. 05-07-039). On October 6, 2005, the CPUC approved the utilities' long-term RPS plans but required supplemental filings and improvements in future plans, including improved contingency planning and quantifying a "margin of safety" for both annual procurement targets and the 2010 target (D. 05-10-14). The CEC, meanwhile, has published its Renewable Portfolio Standard Eligibility Guidebook (500-04-002F1), its New Renewable Facilities Program Guidebook (500-04-001F), and its Overall Program Guidebook for the Renewable Energy Program (500-04-026), as well as related policy decisions.

[33] California Energy Commission. "Implementing California's Loading Order for Electricity Resources." CEC-400-2005-043, July 2005. http://www.energy.ca.gov/2005publications/CEC-400-2005-043/CEC-400-2005-043.PDF.

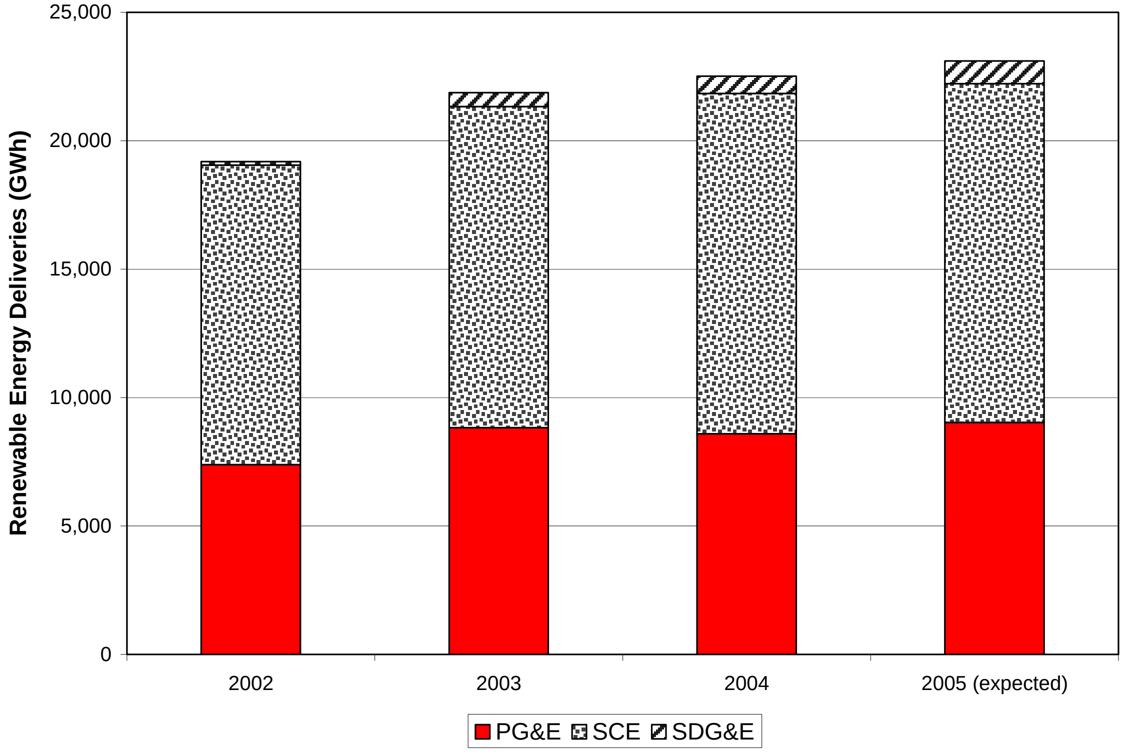


Figure I-1. Early Growth in IOU Renewable Energy Deliveries

To date, the vast majority of the aggregate increase in the IOUs' renewable energy purchases has come from pre-existing renewable energy generating units in California that were previously delivering electricity to other California load-serving entities. Few new renewable energy projects have yet come on-line. In fact, statewide renewable energy generation only increased from 28,908 GWh in 2002 to 29,238 GWh in 2004. The resulting increase in statewide renewable generation of 330 GWh is small relative to the 3,320 GWh increase in the IOUs' renewable energy purchases during the same timeframe, demonstrating that the IOUs' purchases to date have not come from significant amounts of new renewable generation.[34] On a statewide basis, the percentage share of electricity supply met with renewable energy did not increase from 2002 to 2004. As a result, California as a whole has fallen behind schedule in meeting its aggressive renewable energy targets,[35] and IOU purchases to date have mostly shifted existing renewable energy supply from other buyers to the state's IOUs (with little commensurate increase in overall renewable energy supply in the state).

[34] The exception is SDG&E, whose 2002 interim procurement did lead to a number of contracts with sources of new renewable energy supply that have subsequently come on line.
[35] California Energy Commission. "Implementing California's Loading Order for Electricity Resources." CEC-400-2005-043, July 2005. http://www.energy.ca.gov/2005publications/CEC-400-2005-043/CEC-400-2005-043.PDF.

It should be emphasized, however, that it takes time for new renewable energy projects to be built,[36] and the state's IOUs are now making significant commitments to new sources of renewable energy. As shown in Table 1 (and summarized more concisely in Figure 2), since 2002, approximately 1,710 – 3,030 MW of new renewable energy capacity has been contracted by the three IOUs (either already approved by the CPUC or otherwise awaiting approval). More contracts for new capacity are expected, with all three utilities having recently commenced their 2005 requests for offers (RFO), and additional contracts under the 2004 RFOs still possible.

Table I-1. IOU Contracts for New Renewable Energy Supply*

	PG&E	**SCE**	**SDG&E**	**TOTAL**
Wind (MW)	167 – 190	121 – 345	358	**646 – 893**
Wind Repowering (MW)	84 – 99	37	0	**120 – 135**
Geothermal (MW)	0	30 – 120	0	**30 – 120**
Biomass (MW)	18	12 – 37	75	**106 – 131**
Solar Thermal Electric (MW)	0	500 – 850	300 – 900	**800 – 1750**
Small Hydropower (MW)	0	0	5	**5**
Total Capacity (MW)	**269 – 306**	**700 – 1389**	**738 – 1338**	**1707 – 3033**
Total Incremental Supply (GWh/yr)	**~ 970**	**~ 1780 – 4160**	**~ 2310 – 3560**	**5050 – 8690**
Total Incremental Supply as a Percentage of 2004 Load (%)	**1.3%**	**2.4% - 5.7%**	**14.6% - 22.5%**	**3.1% - 5.4%**

* Includes all contracts for new renewable energy capacity known to have been submitted to or approved by the CPUC since 2002. Table updated through October 28, 2005. Capacity additions do not include four contracts that SCE signed under its 2002 interim RFO, as at least one of those contracts has subsequently been terminated (TrueSolar), and information on the resource type and/or project size of the other three is not publicly available. Total incremental renewable energy capacity and supply derives from data submitted to the CPUC (Advice Letter filings and RPS compliance reports), and from other data (for SDG&E, new renewable energy contract information from before its 2004 RFO came from SDG&E's website; assumed capacity factors were used to convert MW to GWh - 35 percent for wind, 23.9 percent for solar thermal electric [same as SCE's solar thermal contract], and 85 percent for biomass).

[36] Experiences from the solicitations to date shows that it can often take a minimum of two years from RFO issuance to actual project construction.

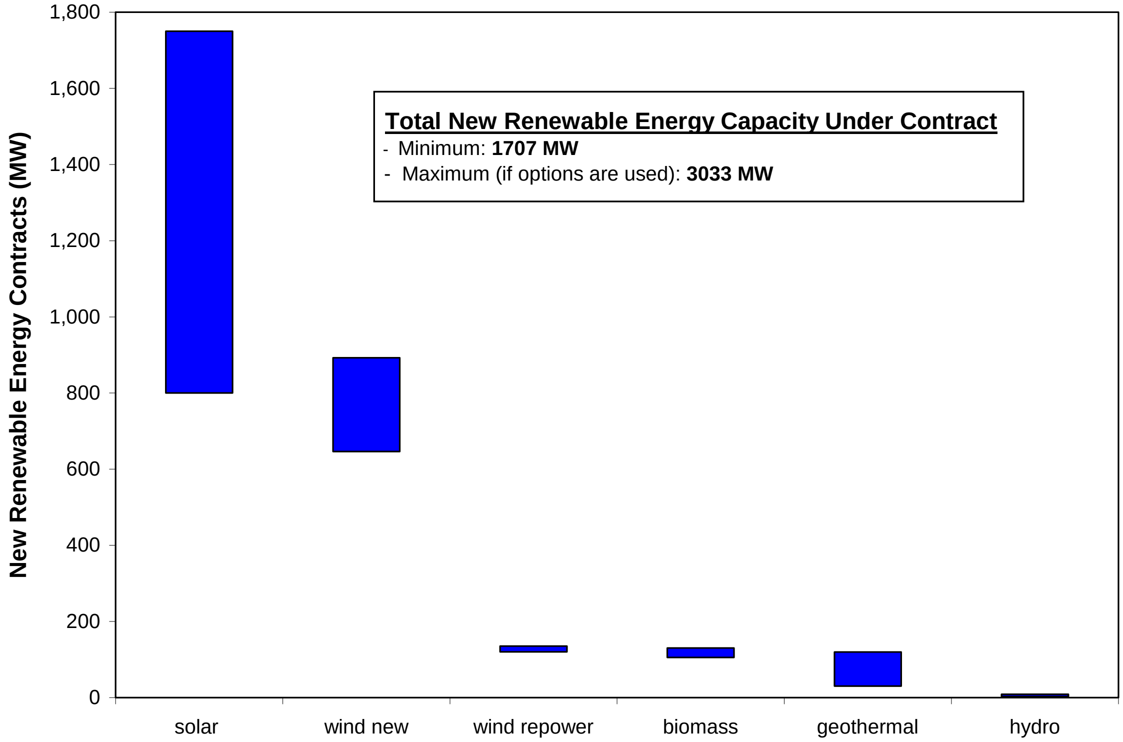


Figure I-2. New Renewable Capacity Under Contract to the State's IOUs Since 2002

SCE and SDG&E are in the lead in terms of new renewable energy capacity under contract. SCE has at least 700 – 1,389 MW of contracted capacity; if these projects achieve commercial operation, their incremental generation will equate to 2.4-5.7 percent of SCE's 2004 load. SDG&E has clearly been the most aggressive utility in contracting for new renewable energy generation, as a percent of its load, with 738 – 1,338 MW of new renewable capacity under contract, equating to roughly 14.6-22.5 percent of SDG&E's 2004 load. PG&E's purchases have lagged, with 269-306 MW of new capacity under contract, equating to just 1.3 percent of 2004 load. In aggregate, the state's major IOUs have committed to new renewable energy sources that could deliver enough electricity to equate to 3.1-5.4 percent of the combined load of the three IOUs in 2004.

As described later, there may be significant risk associated with *some* of these renewable purchases. In some cases, utilities have signed contracts with projects that plan to use renewable technologies that are not yet fully commercial (e.g., new solar thermal dish electric technologies), while in other cases fuel supply, permitting, or transmission risks may prevent contracted capacity from achieving commercial operation. Consequently, ongoing monitoring of the status of these contracts will be essential to ensure that actual deliveries are on target to meet RPS obligations.

In addition to these procurement efforts, the state's utilities have submitted (and the CPUC has conditionally approved[37]) illustrative plans to achieve the state's 20 percent renewable energy goal by 2010. As shown in Table 2, PG&E's procurement plan calls for 1,650 MW of *additional* renewable energy capacity by 2010, growing to 1,950 MW of capacity by 2014 in order to achieve PG&E's 23 percent goal by that date.[38] After some wind repowers and expansions, and assuming that the non-solar contracts signed as a result of its 2003 RFO were successfully developed, SCE's most recently filed plan illustratively calls for an *additional* 400 MW of incremental renewables capacity by 2010, increasing to 990 MW by 2014 and equating to 20 percent of retail load.[39] SDG&E's plan calls for a *total* of 780 MW of renewable energy by 2010, growing to 1,075 MW by 2014 in order to meet a 24 percent target by that date.[40]

Table I-2. Summary of the IOUs' Long-Term Renewable Energy Plans (renewable energy capacity and percentage of load)*

	2010	2014
PG&E	1650 MW (20%)	1950 MW (23%)
SCE	400 MW (20%)	990 MW (20%)
SDG&E	780 MW (20%)	1075 MW (24%)

* Note that these long-term plans present data in different forms, making applies-to-apples comparisons impossible. Data for SDG&E reflect *total* renewable capacity needs, for example, while PG&E and SCE data reflect *incremental* needs (and from different baselines).

Barriers to Achieving the State's Aggressive Renewable Goals

California's regulatory agencies, regulated utilities, and other stakeholder participants are working hard to implement the state's RPS. Even with best efforts going forward, however, the procurement results to date shown above, combined with an understanding of the time it takes to bring new renewable energy projects online and the transmission constraints that continue to hinder renewable energy development, suggest that some of the IOUs may face challenges in achieving renewable energy deliveries of 20 percent by 2010.[41] With *final* rules for the participation of ESPs and CCAs in the RPS not expected until 2006, these parties (which, at present, serve approximately 13% of load in the state)

[37] D. 05-10-014.
[38] Pacific Gas and Electric Company. "Renewable Portfolio Standard, 2005 Renewable Energy Procurement Plan – Part 1." R.04-04-026. July 28, 2005.
[39] Southern California Edison. "Revised Renewable Procurement Plan, 2005-2014." R.04-04-026. July 6, 2005.
[40] San Diego Gas & Electric. "Short-Term and Long-Term Renewable Procurement Plans." R.04-04-026. May 12, 2005.
[41] The state's major IOUs have also submitted to the CEC plans to achieve more aggressive statewide targets for renewable energy (28 percent by 2016 for PG&E and SDG&E, and 31 percent for SCE). These plans do not include comprehensive analysis of the costs or benefits of such augmented targets, though each utility expresses substantial concern about the viability and cost of achieving such aggressive goals. See California Energy Commission. "Revised Investor-Owned Utility Resource Plan Summary Assessment." CEC-700-2005-014. June 2005. http://www.energy.ca.gov/2005publications/CEC-700-2005-014/CEC-700-2005-014.PDF.

may also struggle to achieve a 20 percent target by 2010.[42] Finally, with POUs setting their own renewable energy targets, it is unclear whether these entities are on track to meet the 20%-by-2010 statewide goal.

There are clearly barriers to achieving California's 20 percent renewable energy goal by 2010, much less a more aggressive 33 percent target by 2020. A short and not necessarily complete list of barriers identified by RPS stakeholders includes: (1) the need for and complexity of transmission expansion to access certain renewable resource areas; (2) the renewable electricity delivery requirements imposed by statute and regulatory decisions; (3) concerns that some of the contracted renewable energy projects will not materialize because of siting issues, fuel supply risks, transmission constraints, technical problems, or financing difficulties; (4) the fact that an RPS framework for the state's ESPs and CCAs has not yet been fully developed, and that enforced targets are not imposed on POUs; and (5) the overall complexity of the RPS statute itself.[43]

Though short-staffed and faced with a complex RPS statute, the CPUC has actively sought to address many of these barriers in recent months. Recent CPUC initiatives include opening a docket on renewable energy and transmission; providing additional delivery flexibility by allowing the IOUs to take delivery outside of their service territories; requiring utilities to include some contingency analysis and planning for over-contracting in their long-term RPS planning; beginning to address the RPS compliance framework for ESPs and CCAs; and altering utility RFO requirements based on past experience.

To achieve a more aggressive 33 percent goal, some of the concerns discussed above may grow, and will need to be addressed through new legislation or regulation. The state's IOUs have cited a number of specific concerns with the 33 percent goal, most notably:[44]

- necessary transmission upgrades and the cost of those upgrades;
- electric system operational challenges and reliability impacts of increased intermittent and non-dispatchable generation;
- challenges to deliverability of renewable electricity into local utility service territories, and need for unbundled RECs;
- the availability and potential cost of a balanced mix of renewable energy supply, the sufficiency of SEPs, and the overall impact of the more aggressive goals on retail rates;
- whether similar goals are to be applied to the state's other energy service providers (municipal utilities, ESPs, and CCAs); and

[42] The CPUC is now actively addressing the participation of ESPs and CCAs, with a scoping decision expected in mid-November 2005.
[43] Wiser, Ryan, Kevin Porter and Mark Bolinger. "Preliminary Stakeholder Evaluation of the California Renewables Portfolio Standard." CEC-300-2005-011, June 2005.
[44] See, e.g., California Energy Commission. "Revised Investor-Owned Utility Resource Plan Summary Assessment." CEC-700-2005-014. June 2005. http://www.energy.ca.gov/2005publications/CEC-700-2005-014/CEC-700-2005-014.PDF; and the comments of the three major IOUs on that report - http://www.energy.ca.gov/2005_energypolicy/documents/2005-06-29_hearing/comments/.

- the lack of rigorous analysis of the feasibility, costs, and benefits of achieving the 33 percent target.

The following sections explore many of these concerns and provide preliminary analysis and summary of the information available at this time.

RESOURCE NEEDS[45]

Resource Needs To Support A 33% RPS

At present, California has in place a 20 percent RPS target. In order to determine the resources needed to support a 33 percent renewable portfolio standard (RPS), it is necessary to first examine the renewables needed to reach a 20 percent RPS target and build from there. While legislation that set this target required that the 20 percent goal be achieved by 2017, the Energy Action Plan created by the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) identified a target achievement date of 2010. All of the investor owned utilities are working toward achieving that goal by 2010, and all have indicated an expectation of meeting that goal. For the purpose of this report, we assume the 20 percent target is achieved by 2010 and examine the renewable resources needed to achieve 33 percent by 2020.

As part of the 2005 Integrated Energy Policy Report (IEPR) process, the CEC developed and published a report on expected electricity demand over the next 10 years. This report includes load forecast data provided by the investor owned utilities (IOUs) and leading municipal utilities to serve the IEPR process. The CEC has also independently made such a forecast. The utility forecast, which has been extrapolated through 2020, is summarized as follows:[46]

Table II-1 California Electricity Consumption by Utility Planning Area*

Terawatt Hours											
Year	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
PG&E PA*	105.0	106.3	107.6	109.0	110.3	111.7	113.1	114.5	115.9	117.3	118.8
SCE PA*	102.7	105.6	108.5	111.6	114.7	117.9	121.2	124.6	128.1	131.7	135.4
LADWP	25.8	26.2	26.5	26.9	27.3	27.7	28.1	28.5	28.9	29.3	29.7
SMUD PA	11.4	11.6	11.8	12.1	12.3	12.5	12.8	13.0	13.3	13.6	13.8
SDG&E	21.4	21.8	22.3	22.7	23.2	23.6	24.1	24.6	25.1	25.6	26.1
BGP PA	3.6	3.6	3.7	3.7	3.8	3.8	3.9	3.9	4.0	4.1	4.1
Total	**269.9**	**275.1**	**280.5**	**286.0**	**291.6**	**297.3**	**303.1**	**309.1**	**315.2**	**321.5**	**327.9**

*Load Data for IOU's alone is approximately 75 percent of total.

---

45 / The resource and transmission supply profiles developed in this section to meet a 33 percent renewable portfolio standard requirement, along with their associated costs, are input values used for the Cost and Rate Impact Analysis Section of this report (Section III).

46 / *Electricity Demand Forecast Comparison Report*, Staff Report June 2005 CEC-400-2005-037

Source: Data as provided by Utilities and published in CEC-400-2005-037 “Electricity Demand Forecast Comparison Report”

Presuming that the 20 percent RPS is in fact achieved by 2010, we have estimated the annual incremental renewable energy needs of the major utility planning areas in the state. The deployment estimate assumes that one tenth of the difference between 20 percent of the projected load in 2010 and 33 percent of the projected load in 2020 was secured for incremental renewable energy purchase by the beginning of each year between 2011 and 2020. Such a forecast of load growth and a renewable energy deployment scenario yields the following renewable energy acquisition scenario for the state as a whole. For the purpose of the cost and rate analysis described in Section III of this document, only the loads and renewable resource requirements for the investor owned utilities were used.

Table II-2 Incremental Annual Renewable Energy Procurement Requirements

Terawatt Hours											
											Cumulative Total
Year	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
PG&E PA	1.6	1.7	1.7	1.8	1.8	1.8	1.9	1.9	2.0	2.0	**18.2**
SCE PA	1.9	2.0	2.1	2.2	2.3	2.5	2.6	2.7	2.8	2.9	**24.1**
LADWP	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	**4.6**
SMUD PA	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	**2.3**
SDG&E	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	**4.3**
BGP PA	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	**0.6**
Total	**4.6**	**4.8**	**5.0**	**5.1**	**5.3**	**5.5**	**5.7**	**5.9**	**6.1**	**6.3**	**54.2**

Renewable Energy Resources

As part of the 2005 Integrated Energy Policy Report process, the CEC held a series of workshops that presented data regarding renewable energy resources and costs, natural gas supply issues and cost forecasts, utility planning data and load analysis, and transmission issues as related to future renewable energy deployment. The data presented at the workshops were based on work conducted by and for the CEC, including perspectives and analysis from the private sector. One of the purposes of the workshops was to invite stakeholder feedback regarding the subject matter and to provide comments on the many CEC draft reports. The renewable energy resource and cost data presented here were largely based on 2005 IEPR workshop reports that were posted and discussed during the summer.[47]

[47] / *Strategic Value Analysis for Integrating Renewable Technologies in Meeting Target Renewable Penetration;* Consultant Report in support of the 2005 IEPR. Davis Power Consultants; June 2005. *Geothermal Strategic Value Analysis;* Draft Staff Paper in support of the 2005 IEPR. Elaine Sison-Lebrilla and Valentino Tiangco, June 2005.

From a review of these reports we believe there are sufficient developable renewable energy resources of commercial quality within California to serve a 33 percent RPS. However, permitting and transmission constraints is likely to make timely achievement of a 33 percent RPS exclusively with in-state resource more difficult and more expensive than a strategy that includes looking to other western states for some of California renewable energy needs.

Below is a summary of available commercial-quality renewable resources that have been identified as being developable:

Table II-3 Renewable Resources Available to California (Capacity in peak MW)

Wind

	Newly Developable Capacity – High Speed Wind Sites (MW)	Before 2010: Allocated to 20 percent (MW)	After 2010: Available for 33 percent (MW)
California Wind			
Tehachapi Phase 1	700	700	0
Tehachapi Phase 2	900	300	600
Tehachapi Phase 3	1700	0	1700
Tehachapi Phase 4	1200	0	1200
Solano	300	300	0
Altamont Repowering	1 TWhr	1 TWhr	
Altamont Expansion	130	130	0
San Diego	750	150	600
San Bernadino	280	170	110
Siskiyou	200	100	100
Lassen	300		300
Shasta	200		200
Colusa/Lake	300		300

Developing Cost-Effective Solar Resources with Electricity System Benefits; In Support of the 2005 Integrated Energy Policy Report; Staff Paper – George Simons, June 2005. CEC-500-2005-104.
Strategic Value Analysis – Economics of Wind Energy in California, Draft Staff Paper – Dora Yen-Nakafuji, June 2005. CEC-500-2005-107-SD
Biomass Strategic Value Analysis, In Support of the 2005 Integrated Energy Policy Report, Valentino Tiangco, Prab Sethi & Zhiqin Zhang, June 2005. CEC-500-2005-109-SD
Renewable Energy and Electric Transmission Strategic Integration and Planning: Inter-state Generation and Delivery of Renewable Resources into California from WECC States, Consultant Report – Center for Resource Solutions; Davis Power Consultants; Electranix; Weiser Associates, May 2005.
Revised Investor-Owned Utility Resource Plan Summary Assessment, 2005 IEPR – Proceeding Docket #04-IEP-1. Staff Report, June 24, 2005. CEC-700-2005-014

Wind (continued)

	Newly Developable Capacity – High Speed Wind Sites (MW)	Before 2010: Allocated to 20 percent (MW)	After 2010: Available for 33 percent (MW)
Out of State Wind			
Southern Oregon	1200		1200
Stateline OR/WA	3000	500	2500
Pyramid Lake NV	1000		1000
NE NV	1000		1000
New Mexico	1000		1000
TOTAL	**15560**	**3750**	**11810**

Geothermal

	Newly Developable Capacity (MW)	Before 2010: Allocated to 20 percent (MW)	After 2010: Available for 33 percent (MW)
California Geothermal			
Salton Sea	1400	600	800
Brawley	325	135	190
Heber	100	50	50
Sulfur Bank	40	40	0
Medicine Lake	300	175	125
North Geysers	400	100	300
Nevada Geothermal			
Dixie Corridor	600	100	500
Washoe NV	500		500
TOTAL	**3665**	**1200**	**2465**

Biomass

	Newly Developable Capacity (MW)	Before 2010: Allocated to 20 percent (MW)	After 2010: Available for 33 percent (MW)
Urban Muni Waste	860	40	820
Dairy	37	21	16
Waste Water Treatment Plant	58	47	11
Landfill Gas	500	180	320
Forest Management	320	0	320
TOTAL	**1775**	**288**	**1487**

Solar

	Newly Developable Capacity (MW)	Before 2010: Allocated to 20 percent (MW)	After 2010: Available for 33 percent (MW)
Bulk CSP - S. Cal	10,000	200	9800
Bulk CSP - N. Cal	200	0	200
Distributed Solar	5000	200	4800
TOTAL	**15200**	**400**	**14800**

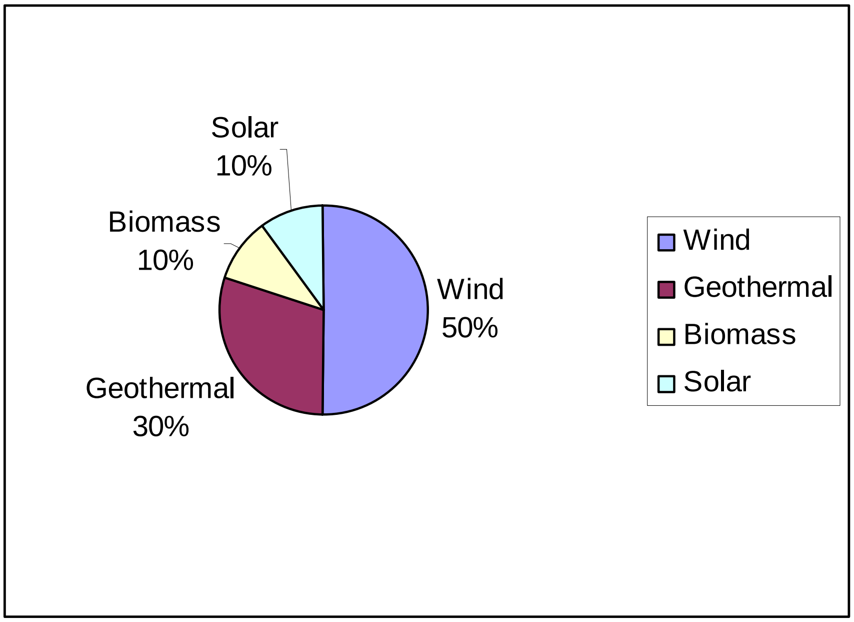
Source for Table III-3: Tehachapi Study Group; Imperial Valley Study Group; CEC SVA and HetchyPIER

Resources were identified as "Allocated to 20% " RPS based on the more detailed economic evaluations of specific renewable resource areas conduced by the CEC under the SVA Program, along with judgments we made as to the pace at which new major transmission projects could come on line prior to 2010. Resource with highly favorable economics identified in SVA were presumed to come online prior to 2010, unless they were subject to major transmission additions that were expected to come on line after 2010.

Renewable Energy Resource Mix

We have developed a specific resource mix to use in this analysis based on the developable resources identified for the various technologies, the plausible transmission upgrades and additions during this period of time, and the economics and characteristics of each technology.

Figure II-1---- Renewable Resource Portfolio Developed for this Analysis



Due to the relatively low cost of wind power, and the strength and depth of the wind power development community, we targeted 50 percent of the renewable energy needs to wind. Geothermal power, with relatively good economics, a solid resource base, and base load/firm capacity characteristics, was projected to provide 30% of the energy. Biomass power in general has favorable economics. But the development potential of biomass is contingent on securing long term fuel supplies, with each project requiring a narrow range of fuel specification. Biomass projects tend to be of modest scale and linked geographically to local fuel sources. For these reasons, biomass was only projected to supply 10% of the renewable energy needs. Solar power (both thermal solar electric and PV in a bulk power mode) is still an emerging technology area with relatively high cost, though it has vast resource potential and an excellent correlation between production and system load. Solar was projected to serve 10% of the energy needs.

The postulated renewable resource mix has a somewhat higher percentage of wind power than the current mix and the 2010 mix projected by utilities in the most recent RPS procurement plans. The large quantity of developable wind capacity in the Tehachapi Pass region can not reach markets until there are substantial transmission line upgrades and additions in the region, providing linkages to both southern and northern California. Most of those additions cannot be brought on line until after 2010.

Table II-4 IOU Planning Area Incremental Annual Renewable Energy Procurement Requirements

Terawatt Hours											
											Cumulative Total
Year	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
PG&E PA	1.6	1.7	1.7	1.8	1.8	1.8	1.9	1.9	2.0	2.0	**18.2**
SCE PA	1.9	2.0	2.1	2.2	2.3	2.5	2.6	2.7	2.8	2.9	**24.1**
SDG&E	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	**4.3**
Total	**4.0**	**4.1**	**4.3**	**4.4**	**4.6**	**4.7**	**4.9**	**5.1**	**5.2**	**5.4**	**46.7**

The actual renewable energy mix under a future expanded RPS will be driven by utility needs and the initiative of the renewable development community. While wind energy busbar costs are low, there are potential concerns with siting, intermittency, integration challenges, and contribution to resource adequacy. Should there be less wind energy in the actual renewable mix, there are significant quantities of the other renewable energy resources to replace the reduced wind.

Renewable Energy Capacity Needs

To compare the renewable energy resource availability to the renewable energy resource needs, the annual renewable energy requirements from Table II-2 were converted to Renewable Capacity using established capacity factor assumptions for each technology. While there are major concentrations of renewable energy in distinct geographic regions, these regions are reasonably well distributed throughout the state. With the development of transmission system upgrades and additions identified below, these renewable resources are assumed to be deliverable throughout the state.

Table II-5 Annual Incremental Capacity Need by Technology**

(Megawatts)											
Year	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**Total**
Wind	646	669	693	718	744	771	798	827	856	886	7608
Geothermal	149	154	160	166	172	178	184	191	198	205	1756
Biomass	49	51	53	55	57	59	61	63	65	67	579
Solar	226	234	243	251	260	270	279	289	300	310	2663
Total	**1070**	**1109**	**1149**	**1190**	**1233**	**1277**	**1323**	**1370**	**1418**	**1469**	**12,606**

***RE Mix All IOU PA Scenario1:** Planning Area Totals include loads served by ESPs and CCA entities within the IOU Planning Areas

**Solar is presumed to include a mix of concentrating solar and non-self-gen “bulk” photovoltaics. Additional on-site PV generation is anticipated, but would be part of utility, ESP and CCA RE mandates.

While these projections of new renewable energy needs are quite large, they are well within the capability of the developable resource potential California and neighboring states.

Table II-6 Comparison of Resource Needs and Developable Resource

Resource	**Projected Resource Need**	**Identified Resource Available**
Wind	7,600 MW	11,800 MW High Speed Sites 19,000 MW Low Speed Sites
Geothermal	1,800 MW	3,400 MW
Biomass	600 MW	1,500 MW
Solar	2700 MW	14,000 MW

Source: Tehachapi Study Group; Imperial Valley Study Group; CEC SVA and Hetchy-PIER

Projected Renewable Energy Costs

Renewable energy costs have been decreasing over the past two decades as production volume has grown and as innovation has continued. For some technologies, costs have also decreased due to increased unit or plant size. These cost reduction trends have been studied extensively and documented by the DOE, EPRI, the CEC and others.

Over the past 18 months, cost reductions have been tempered, and in some cases costs have increased due to external factors. Several underlying reasons for the cost increases have been postulated and include the relative deterioration of the dollar-euro exchange rate,[48] the rapid increase in steel prices as economic expansion in eastern Asia continues, and the dramatically rising demand (outstripping supply) for renewable energy hardware throughout the western US and Europe.

It is difficult to project whether the recent price run-up for renewable energy hardware is temporary, with continued cost reductions once supply comes back into balance with demand; or if prices will start to rise over the long term, at least matching general inflation.

Projected renewable electricity costs were largely taken from the series of Strategic Value Analysis reports published by the CEC for the 2005 Integrated Energy Policy Report (IEPR). Exceptions to the Strategic Value Analysis (SVA) projections are noted. Costs of energy (COE) were projected both with and without the current set of production and investment tax credits available to renewable energy today. And "high" and "low" levelized costs of energy (LCOE) for each technology were projected to bracket the competing trends identified above. Costs in the three cases were projected to remain flat through the analysis period.

Table II-7 Case 1 - Projected Renewable Electricity Costs Levelized Nominal Dollar COE Plant Service Life 2015 through 2040 Assumes no PTC or ITC*

Technology	"Expected" LCOE $/MWhr	Low LCOE $/MWhr	High LCOE $/MWhr
Wind	66	58	83
Geothermal	86	68	100
Biomass – Dairy and LFG	58	48	78
Biomass – Ag Residues	88	78	108
Concentrating Solar	120	100	160
PV	200	120	300

PTC = Production Tax Credit, ITC = Investment Tax Credit.
Source: Strategic Value Analysis and 2005 IEPR Documentation with adjustments by CRS

[48] / Many of the technology components are imported from Europe, particularly for wind turbines.

Table II-8 Case 2 - Projected Renewable Electricity Costs Levelized Nominal Dollar COE Plant Service Life 2015 through 2040 Assumes PTC for wind, biomass and geothermal and 30 percent ITC for solar

Technology	"Expected" LCOE $/MWhr	Low LCOE $/MWhr	High LCOE $/MWhr
Wind	48	40	65
Geothermal	68	50	82
Biomass – Dairy and LFG	40	30	60
Biomass – Ag Residues	70	60	90
Concentrating Solar	90	80	120
PV	160	90	240

Source: Strategic Value Analysis and 2005 IEPR Documentation with adjustments by CRS

Price Projection Ranges: The high and low ranges reflected for individual technology electricity prices in general show a broader range on the high side than on the low side. The uncertainties associated with future renewable energy prices are largely driven by uncertainty of future capital costs as well as uncertainty regarding the quality of the renewable resources that are sold into the California RPS market.

Actual historical data and past projections from DOE, the CEC and EPRI indicate that renewable energy capital cost reductions have been substantial and will continue well into the future. However, renewable technologies are capital intensive, and contain many commodity materials that are in high demand worldwide. This suggests that, at a minimum, renewable project capital costs will bear the consequences of upward price pressure on materials and labor.

While the solar resource is vast and relatively uniform (across geographic regions), the exploitable wind and geothermal resources are highly variable. There is 50% more annual energy in Class 7 winds compared with Class 5 winds. While there are still large quantities of excellent wind resource throughout the far west, it may not be possible to get to that superior resource due to transmission limitations. So there may be a need or desire to use Class 4 or even Class 3 wind resources to provide needed energy. There is a wide range in the quality of geothermal energy from an enthalpy perspective (temperature and pressure). The lower quality resources are more expensive to exploit. Equally important are the levels of contaminants that are contained in geothermal fluids. Some of the most prevalent geothermal resource in California contains high level of contaminants that measurably drive up capital cost. While research is underway to investigate options to deal with the contaminants in a cost effective manner, it is not clear that expensive materials for casings, pipes and vessels will not be required.

Taking all of these factors into account, energy price ranges were postulated by CRS. In general, percent reductions (from the reference case) for the low range were lower than the percent increase for the high range. This was not meant to reflect a perspective that expected future costs are on balance higher than the reference case, but only that the factors that could result in price increases in the future could have a higher downside impact than the factors that would result in continued price reductions.

"Low" levelized cost of electricity numbers range from -12% for wind and residue biomass to -40% for PV, which is judged to still have measurable "technology breakthrough" improvement potential. Geothermal and concentrating solar were judged to have an intermediate -17 to -20% low cost opportunity. The "high" cost scenarios ranged from +25% for wind to +35% for biomass and concentrating solar, and +50% for PV (approximately reflecting today's PV prices).

Basis and Adjustments

<u>Wind:</u> The CEC Wind SVA Draft Report identifies 2005 capital cost of $1020/kW dropping to $663/kW in 2017 (these data were derived from a 2003 Navigant study). CRS discussions with knowledgeable industry representatives suggest that actual 2005 capital cost is 30 percent to 40 percent higher than the CEC estimate; and that suggested future cost reductions are overly optimistic. CRS increased CEC capital cost estimates by 35 percent, resulting in approximately 25 percent increase in LCOE.

<u>Biomass:</u> The CEC SVA results were used. CRS discussions with knowledgeable industry representatives suggest that assumed fuel cost may be optimistic (given the difficulty and cost of fuel collection). There are several state and federal programs that are moving to support residue management in forest and agricultural industries. Without definitive analysis regarding actual fuel management costs that should be assumed, and given the federal and state initiatives to support forest and agricultural industries, we did not make any adjustments to CEC SVA costs.

<u>Geothermal:</u> The CEC SVA results were used. Of particular note however are the SVA estimates for Salton Sea projects. Capital cost ranges in the SVA report range from $2400/kW to just under $5000/kW. CRS discussions with knowledgeable industry representatives suggest that actual costs are likely to be approximately the average of those estimates. This is particularly relevant due to the sheer size of the Salton Sea resource (1400 MW).

<u>Concentrating Solar Power</u>: CEC SVA results projected $60/MWhr in the near term. CRS discussions with knowledgeable industry representatives suggest that costs will be approximately double that in the near term (however, the SES-SCE and SDG&E deals are said to be below $80/MWhr). We adjusted costs up to $90/MWhr for the ITC case and $120/MWhr for the non-ITC case based on the broad range of perspectives. CSP and PV costs are likely to drop with large deployment in the 2010 decade relative to the other technologies.

<u>PV:</u> The CEC SVA results were used. The CEC analysis suggests slow reduction of PV cost over time.

<u>Production and Investment Tax Credits (PTC and ITC)</u>

Case 1 represents a base case, and assumes the elimination of PTC and ITC supports during the study period.

Case 2 assumes that production and investment tax credits will continue as they are now configured through the entire study period. This is a liberal assumption given the fact that PTC and ITC extensions have become a significant political battle each Congressional cycle. The value of these tax credits are enormous to the state's energy consumers, so we assume that the state's energy companies, consumer advocates and government officials will continue to press Washington to provide stable "tax equalization" support for renewable energy into the indefinite future.

The present set of baseline gas price forecast also assumes that the myriad of tax incentives for that energy resource will continue unabated into the indefinite future. This subsidy has the effect of holding prices relatively low through the study period (the baseline CEC gas price forecast for 2020 projects nominal gas prices to be only $10.33 per million BTU. This compares to the 2006 forward price on the NYMEX (at the November 2005 date of this draft) of between $11 and $14/million BTU.

Transmission Costs

Like large hydropower, much of the most cost effective renewable energy resources are located remote from California load centers. Fortunately, most of the renewable energy resources are located close to existing transmission corridors. Several assessments have been made by California utilities the CPUC, Cal ISO and CEC staff and consultants to evaluate the transmission expansion needs for serving an expanded RPS.[49] Under the direction of the CPUC, two significant study collaboratives, involving utility, developer and regulatory stakeholders, have occurred to examine transmission needs and opportunities associated with major renewable resource regions.[50] The Tehachapi Study Group is examining transmission expansion options to support up to 4500 MW of new wind capacity to serve California loads. The Imperial Valley Study Group is examining transmission issues and options to support the delivery of over 2500 MW of new

---

[49] / *Upgrading California's Electric Transmission System: Issues and Actions for 2005 and Beyond;* CEC Staff Report prepared in support of the 2005 IEPR; CEC 700-2005-018; July 2005
CPUC Transmission Plan for Renewables
Renewable Energy and Electric Transmission Strategic Integration and Planning: Delivery of Renewable Resources into California from WECC States; May 2005
PG&E Area Conceptual Plan for Importing Tehachapi Area Generation; Presentation to the CEC; May 2005
[50] / *Techachapi Collaborative Study Group Report;* Filed at the CPUC March 16, 2005
Imperial Valley Study Group – Study Alternatives – Summary of Findings to date; Presentation by IID, June 2005

geothermal, solar and wind capacity from the resource rich Imperial Valley to load centers in Los Angeles and San Diego.[51]

Transmission upgrade and expansion will be required across the state and region over the next two decades to accommodate load growth experienced over the past and current decade independent of an RPS. It is difficult to project a specific incremental transmission investment by the state that would be necessary to serve only an RPS need.

A compilation of transmission expansion projects over time has been taken from the series of CPUC, utility, CEC and Study Group analysis conducted over the past two years. These projects are outlined in the Appendix to this section. Of those projects, several are underway and will be implemented prior to 2010. Projects beyond 2010 that appear to be focused on renewable energy supply have been identified as "33 percent RPS Transmission Projects". The costs, by year, of these projects are summarized below.

Table II- 9 Transmission Investments Anticipated To Serve RPS and other Load and Capacity Expansion Needs

Year	Capital (thousands)	Capacity (MW)
2011		
2012	$326,806	470
2013	$142,081	150
2014	$1,214,742	1,700
2015	$85,714	200
2016	$158,649	645
2017	$252,781	1,150
2018	$626,898	1,200
2019		
2020	$1,038,576	2,110
	$3,846,247	**7,625**

Note: Thousands of nominal dollars

The "on line" dates for these large transmission projects will not perfectly link with the smooth renewable energy deployment shown in Table III-5. The transmission investment schedule reflects the long lead times required to place new transmission assets into service.

[51] *Development Plan for the Phased Expansion of Transmission to Access Renewable Resources in the Imperial Valley;* Imperial Valley Study Group; September 30, 2005.

Integration Costs

Renewable energy integration costs are indirect costs associated with ongoing utility expenses from integrating and operating renewable energy resources. Integration issues include minute to minute and hour to hour integration of intermittent resources like wind and solar as well as their seasonal and annual integration. All power grids have costs associated with the portfolio of generating plants, the quirks of the delivery system, and the highly dynamic load that the customer base produces. The California system has, and will continue to have costs associated with integration, whether or not we proceed with a 33 percent RPS or not. We have attempted to isolate the potential differences in grid integration costs with regard to the specific nature of a future 33 percent renewable portfolio.

In general, renewable energy is less available on demand than fossil power. To take maximum advantage of renewable resources, one must capture, convert, deliver and consume the energy almost instantaneously when it is available. Though renewables can be turned off if not needed, for solar and wind the fuel cannot be stored. Where biomass fuel can be collected and stored, it more resembles a fossil resource. Where geothermal or hydro power can be "shut in" without loss of the underlying energy, these technologies can also have some of the dispatchability characteristics of fossil power.

Using recent integration publications[52] we made preliminary estimates of intermittency integration costs. These cost estimates are summarized in section III the Cost and Rate Analysis section of the report.

In this assessment, it was assumed that biomass, geothermal and solar power has no unique integration costs. Wind was presumed to have two specific integration costs. The first is attributable to costs associated with regulation and contingency reserves. In a recent publication by Lawrence Berkeley Labs[53], the treatment of integration costs for intermittent resources were evaluated for many western utilities and control areas. Based on actual integration studies, integration costs ranged from a low of below $1/MWhr in California up to about $5/MWhr in Minnesota. Actual resource plan assessment of integration costs ranges from $4/MWhr, to $12/MWhr at a 27% wind penetration level, to as high as $18/MWhr.

---

[52] / Source documents for integration: California Renewables Portfolio Standard; Renewable Generation Integration Cost Analysis; Phase III: Recommendations for Implementation; Consultant Report; July 2004; California Wind Energy Collaborative P500-04-054. Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans; Ernesto Orlando Lawrence Berkeley Laboratory, Environmental Energy Technologies Division, August 2005

[53] *Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans;* Ernesto Orlando Lawrence Berkeley Laboratory, Environmental Energy Technologies Division, August 2005

Wind integration costs will be related to wind penetration rates. Currently, California does not recognize any specific wind integration cost. For the purposes of this assessment, we assumed an integration cost of $2/MWhr for capacity added in 2011, rising to $5/MWhr in 2020.

Intermittency: Wind and solar power need to be consumed as the resource is available. Without close-coupled thermal or electric energy storage, these technologies essentially operate as the underlying resource is available. However, solar energy production from any given plant is highly predictable, and with advances in wind forecasting, day-ahead projections of plant output is expected to improve substantially over the coming decade. Improving day-ahead forecasting for wind could reduce wind integration costs.

Diurnal solar insolation patterns are highly predictable, particularly during the summer peak season in California. There is also a generally favorable correlation between the output of solar power systems and overall system demand. As a result, the non-dispatchable nature of solar power does not pose a significant problem associated with integrating measurable quantities into the California system mix.

Wind energy is reasonably predictable on an annual basis. There is also a wealth of data that will allow seasonal energy projections from large wind plants to be made with a high degree of confidence. However, wind plant output can moderate upward or downward relatively quickly across a period of a few hours. It is difficult to project the output of a wind plant 24 hours ahead with a high degree of confidence. And while there is a reasonably good match between seasonal production profiles for California wind plants and seasonal peak demand, wind production often is quite low during the peak 50 to 100 hours per year. Given these features of wind power, it is important to understand the challenges and costs associated with integrating large quantities into the overall California system mix.

If the output of large quantities of wind power varies rapidly, this will impact second-to-second system regulation, hour-to-hour load following, and day-to-day unit commitment and dispatch.

The CEC has just launched a new and important study to examine these issues and opportunities in more depth. The *Intermittency Analysis Project*, to be completed during 2006, will build on past CEC integration studies as well as several other recent national and international renewable energy integration studies. [54] SMUD has also recently initiated a wind integration study with support from the CEC, which will focus on how wind matches SMUD peak load periods, how other generating resources (including a potential new pumped hydro plant) can compliment wind, and issues surrounding the

[54] / Background studies for Intermittency Analysis Project: *California Renewables Portfolio Standard; Renewable Generation Integration Cost Analysis; Phase III: Recommendations for Implementation;* Consultant Report; July 2004; California wind Energy Collaborative P500-04-054. *The Effects of Integrating Wind Power on Transmission System Planning, Reliability, and Operations of the New Your State Power System;* GE Energy Consulting; March 2005

impacts of high wind plant output during periods of minimum system load. The results of these studies will shed important additional light on this subject.

Using California's Hydro and Natural Gas Resources: The impact of integrating large quantities of wind into a system is a function of the makeup of the remainder of the system. In general, power systems containing large quantities of hydro and gas-fired generation are capable of accommodating large quantities of wind without incurring onerous integration costs. However, to achieve such benefits the hydro and gas resources must have a degree of operational flexibility. California is served by a vast hydro electric resource, including several pumped hydro storage plants. Much of the hydro resource is driven be a "water first" operating philosophy, where dam operation is governed by water needs as opposed to optimal electric power dispatch. However, much of California's hydro resource does have a high degree of operational flexibility.

Much of the gas fired generation deployed in the state over the past 15 years was designed as base load generation and does not have very good operational flexibility. However, gas turbine power systems can be designed with a very wide range of operational flexibility, including fast start-up and shut-down periods, rapid ramp rates, and good part load efficiency. Flexible, intermediate or peaking duty gas turbine power systems, sited close to load centers, would be an excellent complement to large wind and solar deployments. CPUC procurement processes may want to keep this in mind when evaluating the electricity system's future needs. Assessing creative ways of integrating new natural gas generation with a 33 percent renewable portfolio could lead to a more flexible system overall than we see today.

Resource Adequacy

Regarding the issues of meeting resource adequacy requirements with large quantities of wind power, we assumed that 15% of the wind capacity added needs to be supplemented with gas turbine capacity. This assumption is derived from the fact that we have built renewable energy portfolio to serve an energy need (as opposed to the systems capacity needs). The CAISO has indicated an intention to credit intermittent resources at about 28% of their nameplate rating toward RA.

CAISO has been addressing the potential impacts, both qualitatively and quantitatively, as part of its ongoing Market Redesign Technology Update Project (MRTU). One issue that it has begun to quantify is the issue of the contribution of intermittent resources to Resource Adequacy (RA) obligations. In its Revised September 25, 2005 MRTU update, CAISO states the following:

> *The most likely result is that Intermittent Resources will be able to count toward RA approximately 25 – 30% of their full capacity. The ultimate number will probably be based on a historical load factor that will result in a high confidence of delivery for those units.*

To be conservative, we have assumed wind to have a 20% “capacity value”. Actual wind capacity factors were assumed to be 35%. To provide a given quantity of energy, one would deploy roughly 35 MW of (100% capacity factor) combined cycles for every 100 MW of wind capacity alternatively deployed. We have presumed that the 100 MW of wind provides a RA value of 20 MW. To achieve the equivalent RA value of the alternatively deployed 35 MW combined cycle, one would add an additional 15 MW of peaking turbines. So we have added costs for this additional generating capacity.

CAISO will continue with the MRTU process, including fine tuning the Participating Intermittent Resources Program (PIRP), over the coming year. This process will lead to greater understanding of how integrations costs unique to renewables, if any, will factor into planning, grid design, and cost allocation.

APPENDIX II-A   RESOURCE NEEDS

Statewide Renewable Resource Summary

Table 1: Available Renewable Technology Alternatives

Utility	Renewable	Location	MW	2010 Impact Ratio	2010 LCOE (cents/kWh)	2010 Market Price Referent (cents/kWh)	2017 Impact Ratio	2017 LCOE (cents/kWh)	2017 CPUC CC (cents/kWh)
State wide	Biomass Dairy	Diary Manure	38	-4.5	3.76	6.05	-4.5	2.14	9.15
PG&E	Biomass Forestry	RDGE CBN	59	-3	6.49	6.05	-3	5.52	9.15
PG&E	Biomass Forestry	KEKAWAKA	43	-3	7.07	6.05	-3	6.08	9.15
PG&E	Biomass Forestry	HGHLNDJ2	18	-3	10.00	6.05	-3	8.95	9.15
PG&E	Biomass Forestry	WILLITS	35	-3	7.55	6.05	-3	6.55	9.15
PG&E	Biomass Forestry	MIRABEL	18	-3	10.00	6.05	-3	8.95	9.15
PG&E	Biomass Forestry	TRINITY	26	-3	8.45	6.05	-3	7.43	9.15
PG&E	Biomass Forestry	CEDR CRK	39	-3	7.28	6.05	-3	6.29	9.15
PG&E	Biomass Forestry	TYLER	11	-3	13.21	6.05	-3	12.1	9.15
PG&E	Biomass Forestry	BIG MDWS	32	-3	7.79	6.05	-3	6.79	9.15
PG&E	Biomass Forestry	GRSS VLY	40	-3	7.22	6.05	-3	6.23	9.15
PG&E	Biomass Forestry	CH.STNJT	21	-3	9.28	6.05	-3	8.24	9.15
PG&E	Biomass Forestry	JONESFRK	25	-3	8.59	6.05	-3	7.57	9.15
PG&E	Biomass Forestry	PARADISE	26	-3	8.45	6.05	-3	7.43	9.15
State wide	Biomass Landfill Gas	Landfill Gas	318	-4.5	3.23	6.05	-4.5	2.98	9.15
State wide	Biomass WWT	Wastewater Treatment	59	-4.5	4.19	6.05	-4.5	3.79	9.15
State wide	Biomass Urban fuels	Urban Fuel	497	N/A	N/A	6.05	-4.5	6.02	9.15
Imperial	CSP Solar	Imperial	66	-3.2	6.00	6.05	-3.2	6	9.15
PG&E	CSP Solar	Plumas	0	-3	6.00	6.05	-3	6	9.15
SCE	CSP Solar	Riverside	599	-3.2	6.00	6.05	-3.2	6	9.15
SCE	CSP Solar	San Bernardino	447	-1.7	6.00	6.05	-1.7	6	9.15
SDG&E	CSP Solar	San Diego	35	-1.8	6.00	6.05	-1.8	6	9.15
Imperial	Geothermal	Superstition Mountain	10	-15.83	6.48	6.05	-15.83	5.32	9.15

Imperial	Geothermal	East Mesa	75	-5.6	10.11	6.05	-5.6	8.36	9.15
Imperial	Geothermal	Heber	42	-4.55	5.53	6.05	-4.55	4.53	9.15
Imperial	Geothermal	Mount Signal	19	-4.5	5.60	6.05	-4.5	4.59	9.15
Imperial	Geothermal	Brawley North	135	-4.42	6.13	6.05	-4.42	5.51	9.15
Imperial	Geothermal	Brawley East	129	-4.42	9.32	6.05	-4.42	8.47	9.15
Imperial	Geothermal	Brawley Mesquite	62	-4.42	10.17	6.05	-4.42	9.25	9.15
Imperial	Geothermal	Dunes	11	-4.2	8.12	6.05	-4.2	6.7	9.15
Imperial	Geothermal	Niland	76	-3.97	7.38	6.05	-3.97	6.67	9.15
Imperial	Geothermal	Glamis	6	-1.02	9.76	6.05	-1.02	8.07	9.15
Imperial	Geothermal	Salton Sea	1400	-0.6	5.34	6.05	-0.6	4.78	9.15
PacifiCorp	Geothermal	Lake City/Surprise Valley Modoc County	37	-1.05	7.17	6.05	-1.05	6.48	9.15
PacifiCorp	Geothermal	Medicine Lake Telephone Flat	175	-0.48	5.39	6.05	-0.48	4.82	9.15
PacifiCorp	Geothermal	Medicine Lake Fourmile Hill	36	-0.48	6.21	6.05	-0.48	5.58	9.15
PacifiCorp	Geothermal	Honey Lake	2	0.375	5.49	6.05	0.375	4.49	9.15
PG&E	Geothermal	Sulfur Bank Field	43	-2.91	5.54	6.05	-2.91	4.96	9.15
PG&E	Geothermal	Geysers Sonoma & Lake County	400	-2.23	8.14	6.05	-2.23	7.74	9.15
PG&E	Geothermal	Calistoga Napa County	25	-1	7.86	6.05	-1	7.28	9.15
SCE	Geothermal	Long Valley Mono County	71	0.64	4.43	6.05	0.64	4	9.15
SCE	Geothermal	Coso Hot Spring Inyo County	55	5.17	7.70	6.05	5.17	6.97	9.15
SCE	Geothermal	Randsburg	48	5.35	6.08	6.05	5.35	5.47	9.15
PG&E	High Wind	Solano County	275	-0.67	3.38	6.05	-0.67	2.45	9.15
PG&E	High Wind	Alameda County	132	-0.125	3.38	6.05	-0.125	2.45	9.15
SCE	High Wind	San Bernardino County	168	-5.3	3.38	6.05	-5.3	2.45	9.15
SCE	High Wind	Riverside County	1416	-1.4	3.38	6.05	-1.4	2.45	9.15
SCE	High Wind	Tehachapi	1200	0.008	3.38	6.05	0.008	2.45	9.15
SDG&E	High Wind	San Diego	150	-1.6	3.38	6.05	-1.6	2.45	9.15
PG&E	Low Wind	CRAGVIEW	40	-0.3	7.32	6.05	-0.3	4.02	9.15
PG&E	Low Wind	FLTN JT2	3	-0.3	7.32	6.05	-0.3	4.02	9.15
PG&E	Low Wind	VACA-DXN	60	-0.3	7.32	6.05	-0.3	4.02	9.15
PG&E	Low Wind	TRAVISJT	50	-0.3	7.32	6.05	-0.3	4.02	9.15
PG&E	Low Wind	MAINE-PR	50	-0.3	7.32	6.05	-0.3	4.02	9.15
PG&E	Low Wind	WINDMSTR	28	-0.3	7.32	6.05	-0.3	4.02	9.15
PG&E	Low Wind	MOORPARK	50	-0.3	7.32	6.05	-0.3	4.02	9.15
State wide	Resid. Solar	Distributed	500	-2	16.76	11.9	-2	16.76	11.9
			9,431						

(Sources: LCOE & MW values from California Energy Commission; MPR from CPUC)

Source: *Strategic Value Analysis for Integrating Renewable Energy Technologies in Meeting Target Renewable Penetration;* In support of the 2005 IEPR; Davis Power Consultants; June 2005.

Projected Current (Nominal) Dollar Cost of Electricity from Wind Power

Year	LCOE – No PTC $/MWhr	LCOE – with PTC $/MWhr
2005	66	58
2010	46	38
2013	39	30
2017	33	25

Source:
Strategic Value Analysis – Economics of Wind Energy in California
Draft Staff Paper – June 2005
CEC-500-2005-107-SD
Dora Yen-Nakafuji

Table 5. California Economic Wind Potential and Energy Production Potential

(Filtered, 2005 WTLR > 0, 10mi buffer)

	High Wind Speed			Low Wind Speed			Total	
Height m	Land Area Percent	Capacity MW	AEP GWh	Land Area Percent	Capacity MW	AEP GWh	Capacity MW	AEP GWh
30	0.001	2255	7309	0.004	9986	32367	12241	39676
50	0.002	4229	13707	0.006	14859	48160	19088	61867
70	0.002	6071	19676	0.008	19268	62452	25339	82128
100	0.003	8102	26259	0.010	25647	83126	33748	109384

(Filtered, 2007 WTLR > 0, 10mi buffer)

	High Wind Speed			Low Wind Speed			Total	
Height m	Land Area Percent	Capacity MW	AEP GWh	Land Area Percent	Capacity MW	AEP GWh	Capacity MW	AEP GWh
30	0.001	2451	7945	0.005	11783	38192	14235	46137
50	0.002	4809	15589	0.007	16792	54426	21601	70014
70	0.003	7022	22759	0.008	20904	67754	27926	90513
100	0.004	9326	30227	0.010	26915	87236	36241	117463

(Filtered, 2010 WTLR > 0, 10mi buffer)

	High Wind Speed			Low Wind Speed			Total	
Height m	Land Area Percent	Capacity MW	AEP GWh	Land Area Percent	Capacity MW	AEP GWh	Capacity MW	AEP GWh
30	0.001	2458	7968	0.005	11992	38869	14451	46837
50	0.002	4820	15622	0.007	17613	57088	22433	72709
70	0.003	7056	22870	0.009	23197	75187	30253	98057
100	0.004	9397	30458	0.012	30409	98563	39807	129021

(Filtered, 2017 WTLR > 0, 10mi buffer)

	High Wind Speed			Low Wind Speed			Total	
Height m	Land Area Percent	Capacity MW	AEP GWh	Land Area Percent	Capacity MW	AEP GWh	Capacity MW	AEP GWh
30	0.001	2464	7987.8	0.005	11929	38664	14393	46651
50	0.002	4831	15658	0.007	17135	55538	21966	71196
70	0.003	7055	22866	0.008	21538	69809	28593	92674
100	0.004	9392	30441	0.011	28222	91474	37614	121914

Table 8 shows estimated capital costs, operation and maintenance (O&M) costs and capacity factors for the years analyzed. See Appendix A for 2005 base case (high speed wind resource, utility-scale) calculations and results.

Table 8. Cost Analysis Input Parameters [3]

Technology	High Speed Wind Resource			
Year	**2005**	**2007**	**2010**	**2017**
Installed Capital Costs ($/kW)				
Total Wind Turbine Equipment	639	575	479	415
Transportation & Freight	43	38	32	28
Balance of Plant	190	171	143	124
Owner Costs	148	134	111	96
Total Capital Costs	1020	918	765	663
Expenses including Operation & Maintenance ($/kWh)				
Fuel Cost ($/t)	0	0	0	0
Labor Cost ($/kWh)	0.01	0.009	0.006	0.003
Maintenance Cost ($/kWh)	0.007	0.006	0.005	0.003
Insurance/Property Tax ($/kWh)	0.002	0.002	0.002	0.002
Utilities ($/kWh)	0.001	0.001	0.001	0.001
Management/Administration ($/kWh)	0.004	0.004	0.003	0.001
Total Expenses ($/kWh)	0.024	0.022	0.017	0.01
Capacity Factor (%)	**37**	**38**	**40**	**43**

Source: California Energy Commission

Source:
Strategic Value Analysis – Economics of Wind Energy in California
Draft Staff Paper – June 2005
CEC-500-2005-107-SD
Dora Yen-Nakafuji

Table 1: Most-Likely Geothermal Resource Capacity

Geothermal Resource Area	County	MLK MW	Existing Gross MW	MLK-Existing MW
Brawley (North, East South)	Imperial	326	0	326
Dunes	Imperial	11	0	11
East Mesa	Imperial	148	73.2	74.8
Glamis	Imperial	6.4	0	6.4
Heber	Imperial	142	100	42
Mount Signal	Imperial	19	0	19
Niland	Imperial	76	0	76
Salton Sea (including Westmoreland)	Imperial	1750	350	1400
Superstition Mountain	Imperial	9.5	0	9.5
	Imperial Total:	2487.9	523.2	1964.7
Coso Hot Springs	Inyo	355	300	55
Sulfur Bank Field, Clear Lake Area	Lake	43	0	43
Geysers [Lake & Sonoma Counties]	Sonoma	1400	1000	400
Calistoga	Napa	25	0	25
	The Geysers Total:	1468	1000	468
Honey Lake (Wendel-Amedee)	Lassen	8.3	6.4	1.9
Lake City/ Surprise Valley	Modoc	37	0	37
Long Valley (mono- Long Valley) Mammoth Pacific Plants	Mono	111	40	71
Randsburg	San Bernardino/ Kern	48	0	48
Medicine Lake – Fieldwide	Siskiyou	304	0	304
Sespe Hot Springs	Ventura	5.3	0	5.3
Total: Source: California Energy Commission Geothermal Resource Staff Paper		**4825**	**1870**	**2955**

Geothermal Strategic Value Analysis
In Support of the 2005 Integrated Energy Policy Report
Elaine Sison-Lebrilla & Valentino Tiangco
June 2005
CEC-500-2005-105-SD

Table 5: Summary of Geothermal – Levelized Cost of Electricity (2004 current $/kWh).

Technology	Dry Steam													
	Potential Development (MW)	Capital Cost ($/kW)	LCOE (2004 Current $/kWh)											
Year		2005	Transmission		No Transmission		Transmission		No Transmission		Transmission		No Transmission	
Geothermal		Base Case	PTC	No PTC	PTC	No PTC	PTC	No PTC	PTC	No PTC	PTC	No PTC	PTC	No PTC
Geysers	400	3,725	0.0856	0.0967	0.0854	0.0965	0.0816	0.0927	0.0814	0.0925	0.0776	0.0887	0.0774	0.0885

Technology	Dual Flash													
	Potential Development (MW)	Capital Cost ($/kW)	LCOE (2004 Current $/kWh)											
			2005				2010				2017			
Year		2005	Transmission		No Transmission		Transmission		No Transmission		Transmission		No Transmission	
Geothermal		Base Case	PTC	No PTC	PTC	No PTC	PTC	No PTC	PTC	No PTC	PTC	No PTC	PTC	No PTC
Calistoga	25	3,403	0.0859	0.0980	0.0838	0.0948	0.0819	0.0930	0.0798	0.0897	0.0760	0.0871	0.0720	0.0839
Brawley (North)	135	2,638	0.0786	0.0877	0.0669	0.0780	0.0708	0.0820	0.0613	0.0724	0.0644	0.0755	0.0551	0.0662
Brawley (East)	129	4,195	0.1110	0.1221	0.1009	0.1121	0.1032	0.1143	0.0932	0.1043	0.0944	0.1055	0.0847	0.0958
Brawley (South)	62	4,906	0.1309	0.1420	0.1099	0.1210	0.1224	0.1335	0.1017	0.1128	0.1127	0.1239	0.0925	0.1036
Coso	55	3,405	0.0852	0.0963	0.0837	0.0948	0.0785	0.0896	0.0770	0.0881	0.0711	0.0822	0.0697	0.0808
Lake City / Surprise Valley	37	3,146	0.0804	0.0915	0.0780	0.0891	0.0741	0.0852	0.0717	0.0828	0.0670	0.0782	0.0648	0.0759
Medicine Lake (Fourmile Hill)	36	2,674	0.1709	0.1820	0.0677	0.0788	0.1641	0.1752	0.0621	0.0732	0.1556	0.1667	0.0558	0.0669
Medicine Lake (Telephone Flat)	175	2,275	0.0802	0.0913	0.0590	0.0701	0.0749	0.0860	0.0539	0.0650	0.0688	0.0799	0.0482	0.0593
Niland	78	3,249	0.0814	0.0925	0.0803	0.0914	0.0750	0.0861	0.0738	0.0850	0.0678	0.0789	0.0667	0.0778
Randsburg	48	2,815	0.0706	0.0817	0.0664	0.0775	0.0649	0.0760	0.0608	0.0720	0.0587	0.0698	0.0547	0.0658
Salton Sea (Low)	1400	2,250	0.0621	0.0732	0.0585	0.0696	0.0570	0.0681	0.0534	0.0645	0.0513	0.0624	0.0478	0.0589
Salton Sea (High)	1400	4,500	0.1112	0.1224	0.1076	0.1187	0.1031	0.1142	0.0995	0.1106	0.0940	0.1051	0.0904	0.1015
Sulphur Bank	43	2,347	0.0626	0.0737	0.0606	0.0717	0.0574	0.0685	0.0554	0.0665	0.0516	0.0627	0.0496	0.0607
Range		2,250			0.0473	0.0563			0.0432	0.0522			0.0386	0.0476
Range		4,906			0.0889	0.0979			0.0823	0.0912			0.0748	0.0838
Average		3,177			0.0638	0.0728			0.0588	0.0678			0.0534	0.0623

Technology	Binary													
	Potential Development (MW)	Capital Cost ($/kW)	LCOE (2004 Current $/kWh)											
			2005				2010				2017			
Year		2005	Transmission		No Transmission		Transmission		No Transmission		Transmission		No Transmission	
Geothermal		Base Case	PTC	No PTC	PTC	No PTC	PTC	NO PTC	PTC	No PTC	PTC	NO PTC	PTC	No PTC
Long Valley - M-P Leases	71	2,334	0.0594	0.0705	0.0494	0.0605	0.0540	0.0651	0.0443	0.0554	0.0496	0.0608	0.0400	0.0511
Honey Lake	1.9	2,804	0.1077	0.1188	0.0632	0.0743	0.0904	0.1065	0.0549	0.0660	0.0880	0.0991	0.0449	0.0560
[illegible]	11	4,305	0.1005	0.1116	0.0928	0.1039	0.0888	0.0969	0.0812	0.0924	0.0744	0.0855	0.0670	0.0781
East Mesa	74.9	5,141	0.1162	0.1274	0.1151	0.1262	0.1022	0.1133	0.1011	0.1122	0.0847	0.0958	0.0836	0.0947
Glamis	6.4	4,963	0.1640	0.1751	0.1111	0.1222	0.1493	0.1604	0.0976	0.1087	0.1319	0.1430	0.0807	0.0918
Heber	42	2,706	0.0657	0.0768	0.0636	0.0747	0.0572	0.0684	0.0553	0.0664	0.0472	0.0583	0.0453	0.0564
Mount Signal	19	2,746	0.0734	0.0845	0.0645	0.0756	0.0647	0.0759	0.0560	0.0671	0.0545	0.0656	0.0459	0.0570
Sespe Hot Springs	5.3	4,112	0.1094	0.1205	0.0934	0.1045	0.0975	0.1086	0.0818	0.0929	0.0830	0.0941	0.0674	0.0785
Superstition Mountain	6.5	3,211	0.0785	0.0896	0.0743	0.0854	0.0689	0.0800	0.0648	0.0759	0.0573	0.0684	0.0532	0.0643
Range		2,334			0.04	0.049			0.0358	0.0469			0.0326	0.0414
Range		5,141			0.0931	0.1021			0.0818	0.0908			0.0677	0.0767

Source: California Energy Commission staff with assistance from McNeil Technologies under contract 500-00-031.

Table 12: Geothermal Resource's Transmission Impact Ratios

Geothermal Resource	Trans. Costs Million$	Trans. Impact Ratio	2010 LCOE w/PTC & Trans. Costs (cents/kWh)
Salton Sea	$233	-0.6	5.70
Dunes	$4	-4.2	8.88
Glamis	$16	-1.02	14.93
Superstition Mountain	$1.9	-15.83	6.89
Heber	$4	-4.55	5.72
Niland	$4	-3.97	7.50
Mount Signal	$8	-4.5	6.47
Long Valley Mono County	$33.4	0.64	4.37
Coso Hot Spring Inyo County	$53.1	5.17	7.85
Randsburg	$9.1	5.35	6.49
Brawley	$59.5	-4.42	9.17
Medicine Lake Siskiyou County	$170	-0.48	7.49
Geysers Sonoma County	$53.2	-2.23	8.16
Lake County Geysers and Sulfur Bank Field	$55.9	-2.91	5.74
Calistoga Napa County	$3.8	-1	8.19
Honey Lake	$3.8	0.375	9.84
Lake City/Surprise Valley Modoc County	$4	-1.05	7.41
East Mesa	$4	-5.6	10.22
Total	$679.5		

Source: California Energy Commission Consultant Report written by Davis Power Consultant under contract 500-00-031.

Table 12. Estimated electricity generating potential from biomass in California, 2005 resource base[72]

	Potential MWe		Potential GWh		Existing/Planned		Net Technical	
	Gross	Technical	Gross	Technical	MWe	GWh	MWe	GWh
Total Biomass	***10,711***	***4,654***	***79,757***	***34,650***	***969***	***7,216***	***3,684***	***27,434***
Possible Use by Thermal Conversion	8,536	3,671	63,561	27,337	644	4,796	3,027	22,541
Possible Use by Biochemical Conversion	2,175	982	16,196	7,313	325	2,420	657	4,893
Total Agricultural	***2,144***	***1,021***	***15,964***	***7,605***	***141***	***1,051***	***880***	***6,554***
Total Animal Manure	986	389	7,339	2,893	4	30	385	2,863
Total Cattle Manure	612	224	4,555	1,669	4	30	220	1,639
Milk Cow Manure	285	142	2,119	1,060	4	30	138	1,030
Total Orchard and Vine	346	242	2,573	1,801	93	694	149	1,108
Total Field and Seed	575	281	4,281	2,092			281	2,092
Total Vegetable	112	9	835	70			9	70
Total Food Processing	126	101	936	749	44	328	57	421
Total Forestry	***3,628***	***1,934***	***27,013***	***14,404***	***268***	***1,996***	***1,666***	***12,408***
Mill Residue	839	451	6,244	3,355				
Logging Slash	1,079	575	8,035	4,285				
Forest Thinning	1,088	583	8,103	4,345				
Shrub	622	325	4,631	2,419				
Total Municipal	***4,940***	***1,698***	***36,780***	***12,641***	***560***	***4,170***	***1,138***	***8,472***
Biosolids Landfilled	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Biosolids Diverted	61	49	454	363			49	363
Total MSW Biomass Landfilled	1,926	(1)	14,340	(1)	(1)	(1)	(1)	(1)
Total MSW Biomass Diverted	2,142	1,071	15,952	7,976	239	1,780	832	6,197
Landfill Gas (LFGTE)	694	500	5,171	3,724	258	1,921	242	1,803
Biogas from waste-water treatment plants	116	78	863	578	63	469	15	109

(1) Included in LFGTE.

Totals may not add due to rounding.

Biomass Strategic Value Analysis
In Support of the 2005 Integrated Energy Policy Report
Valentino Tiangco, Prab Sethi & Zhiqin Zhang
June 2005
CEC-500-2005-109-SD

Table 25. 2010 LCOE using fluidized bed with and without PTC, wholesale prices of electricity and LCOE of combined cycle (current dollar). Zero transmission costs[88]

Name	County	Capacity (MW)	Transmission Impact ratio	2010 No PTC	2010 with PTC	Wholesale Price CEC 2003 forecast for 2010	Wholesale Price E3 - CPUC Forecast for 2010*	Market Price Referents	LCOE Combined cycle for 2010*
RDGE CBN	Humboldt	59	-3.07	0.0693	0.0649	0.0426	0.06304	0.0605	0.07419
KEKAWAKA	Trinity	43	-3.07	0.0750	0.0707	0.0426	0.06304	0.0605	0.07419
HGHLNDJ2	Lake	18	-3.07	0.1044	0.1000	0.0426	0.06304	0.0605	0.07419
WILLITS	Mendocino	35	-3.07	0.0799	0.0755	0.0426	0.06304	0.0605	0.07419
MIRABEL	Sonoma	18	-3.07	0.1044	0.1000	0.0426	0.06304	0.0605	0.07419
TRINITY	Trinity	26	-3.07	0.0889	0.0845	0.0426	0.06304	0.0605	0.07419
CEDR CRK	Shasta	39	-3.07	0.0772	0.0728	0.0426	0.06304	0.0605	0.07419
TYLER	Tehama	11	-3.07	0.1365	0.1321	0.0426	0.06304	0.0605	0.07419
BIG MDWS	Plumas	32	-3.07	0.0823	0.0779	0.0426	0.06304	0.0605	0.07419
GRSS VLY	Nevada	40	-3.07	0.0766	0.0722	0.0426	0.06304	0.0605	0.07419
CH.STNJT	Tuolumne	21	-3.07	0.0972	0.0928	0.0426	0.06304	0.0605	0.07419
JONESFRK	El Dorado	25	-3.07	0.0903	0.0859	0.0426	0.06304	0.0605	0.07419
PARADISE	Butte	26	-3.07	0.0889	0.0845	0.0426	0.06304	0.0605	0.07419
		393							

Source: Biomass Strategic Value Analysis
In Support of the 2005 IEPR Draft Staff Report
June 2005
CEC-500-2005-109-SD

Table 27. Potential Biomass Generation by County[90]

NAME	Dairy MWe	WWTP MWe	LFGTE NET MWe	Gross MWe	Existing MW	Economical Potential
ALAMEDA	0.05	5.32	29.89	35.26	8.22	27.04
BUTTE	0.06	0.40	1.12	1.59	0.00	1.59
CONTRA COSTA	0.15	2.59	10.88	13.62	3.00	10.62
EL DORADO	0.00	0.22	-0.15	0.07	0.00	0.07
GLENN	0.11	0.00	0.00	0.11	0.00	0.11
IMPERIAL	0.00	0.36	1.35	1.72	0.00	1.72
KERN	3.45	1.69	9.70	14.84	0.28	14.56
LOS ANGELES	0.00	29.48	116.08	145.56	121.10	24.46
MARIN	0.81	0.70	3.11	4.62	0.00	4.62
NEVADA	0.00	0.13	0.47	0.61	0.00	0.61
ORANGE	0.00	9.92	58.37	68.29	34.98	33.31
PLACER	0.08	0.45	3.03	3.56	1.00	2.56
RIVERSIDE	8.81	4.34	16.83	29.98	1.67	28.31
SAN BENITO	0.08	0.07	0.69	0.84	0.00	0.84
SAN BERNARDINO	16.15	3.90	10.96	31.01	0.00	31.01
SAN DIEGO	0.61	8.11	28.24	36.96	16.10	20.86
SAN FRANCISCO	0.00	2.98	0.00	2.98	0.51	2.47
SAN JOAQUIN	2.05	1.51	7.36	10.91	0.80	10.11
SAN LUIS OBISPO	0.00	0.45	4.45	4.90	0.00	4.90
SAN MATEO	0.00	2.02	4.96	6.98	1.90	5.08
SANTA BARBARA	0.03	0.52	1.63	2.18	0.00	2.18
SANTA CLARA	0.00	7.68	6.24	13.92	9.23	4.69
SOLANO	0.00	0.56	0.00	0.56	0.00	0.56
STANISLAUS	0.73	0.00	0.00	0.73	0.00	0.73
TULARE	5.65	0.00	0.79	6.44	0.00	6.44
VENTURA	0.00	2.03	7.72	9.75	3.30	6.45
YUBA	0.16	0.12	1.52	1.80	0.00	1.80
	38.98	85.56	325.25	449.79	202.09	247.71

Source: Biomass Strategic Value Analysis in Support of the 2005 IEPR
Draft Staff Report
June 2005
CEC-500-2005-109-SD

Table 34 Distribution of 2017 Biomass Potential by Type[97]

	URBAN MW	Dairy MW	WWTP MW	LFGTE MW	Gross MW	EXISTING CAP	ECONOMIC POTENTIAL
2017 Projections	974.19	36.99	58.43	495.01	1,564.62	318.61	1,246.00
2010 Distribution	0	21.47	47.12	179.12	247.71	202	
Net	974.19	15.52	11.31	315.89	1,316.91	116.61	1,246.00
Existing 2017 MW	116.61	0	0	0			
2017 Net Incremental MW	857.57	15.52	11.31	315.89	1,316.91	116.61	1,246.00
2010 and 2017 Total	857.57	36.99	58.43	495.01	1,564.62	318.61	1,246.00

Table 40. 2017 LCOEs in Current $ (952 MW total)[103]

Biomass Resource	Capacity (MW)	Transmission Impact ratio	2017 No PTC	2017with PTC	Wholesale Price CEC 2003 forecast for 2017	Wholesale Price E3 - CPUC Forecast for 2017*	Market Price Referents	LCOE Combined cycle for 2017*
Dairy Manure* (200 kW)	37	-4.47	0.0257	0.0214	0.0587	0.07164	0.0605	0.09152
Landfill Gas (1 MW)	499	-4.47	0.0342	0.0298	0.0587	0.07164	0.0605	0.09152
Waste water (1MW)	58	-4.47	0.0423	0.0379	0.0587	0.07164	0.0605	0.09152
Urban Fuels (25 MW)	361	-4.47	0.0423	0.0646	0.0602	0.07164	0.0605	0.09152

* Assumed sales of sludge/fertilizer

Source: Biomass Strategic Value Analysis in Support of the 2005 IEPR
Draft Staff Report
June 2005
CEC-500-2005-109-SD

Bulk Solar Power Resource Potential

Table 7: CSP Economic Potential at County Level (7.0 kWhr/m²-day)

	Suitable Area	Solar Capacity	Energy (25% CF)	Energy (55% C
County	(m2)	(MW)	(GWhr/yr)	(GWhr/yr)
INYO	112,500,000	5,561	12,179	26,793
KERN	929,920,000	45,967	100,669	221,471
LOS ANGELES	340,980,000	16,855	36,913	81,208
RIVERSIDE	101,180,000	5,001	10,953	24,097
SAN BERNARDINO	1,568,920,000	77,554	169,844	373,656
Totals:	3,053,500,000	150,939	330,557	727,225

Source: *Developing Cost-Effective Solar Resources with Electricity System Benefits;* In support of the 2005 IEPR; CEC Staff Paper; George Simons; June 2005

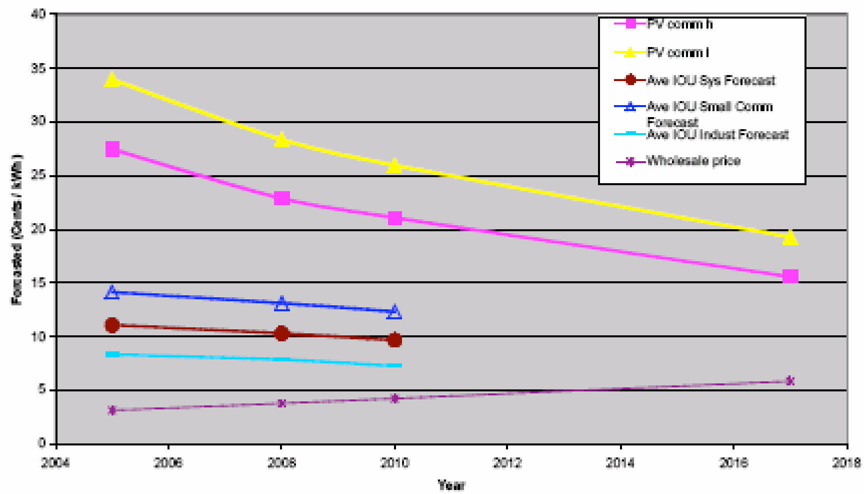
Table 10: DOE Cost Trends for Utility-Scale PV Systems

System Element	Units	2003	2007	2020
Design	$\$/W_{ac}$	0.25	0.15	0.10
Module Price	$\$/W_{p,dc}$	4.80	2.50	1.00–1.50
Direct cost/power	$\$/W_{p,dc}$	3.00	1.65	0.33–0.50
Conversion efficiency	%	14	15	15–20
Direct cost/area	$\$/m^2$	420	250	50–100
Inverter Price	$\$/W_{ac}$	1.10	0.50	0.30
DC-AC conversion efficiency	%	94	96	97
Replacement	Years	5	10	20
Other BOS	$\$/W_{ac}$	0.85	0.60	0.40
Installation	$\$/W_{ac}$	2.50	1.50	0.50
INSTALLED SYSTEM PRICE	$\$/W_{ac}$	6.20–9.50*	5.20	2.30–2.80
System Efficiency	%	11.5	14	16
Lifetime	Years	20	20	30
Degradation	%/Yr	1–2	1-2	1
O&M cost	$\$/kWh_{ac}$	0.08	0.02	0.005
LEVELIZED ENERGY COST	$\$/kWh_{ac}$	0.25–0.40*	0.22	0.6–0.10

Considerations:
LEC is cost to consumer.
2003 numbers taken from example of Figure 4.1.1-3.
LEC is dependent on solar resource (2000 kWh/m²/yr assumed here).
2003 data assume retrofit market; 2007 and 2020 are for new construction.
O&M primarily based on one inverter replacement every 5 years for 2003 figures; every 10 years for 2010 and 2020 figures.
*The ranges reflect the variability in calculations including various incentives and financing assumptions. LECs have been reported previously for year 2000 with incentives included.

Source: National Renewable Energy Laboratory

Figure 11: LCOE for Commercial Building PV versus Forecasted



Rates

Source: California Energy Commission

Summary of Wind Integration Costs

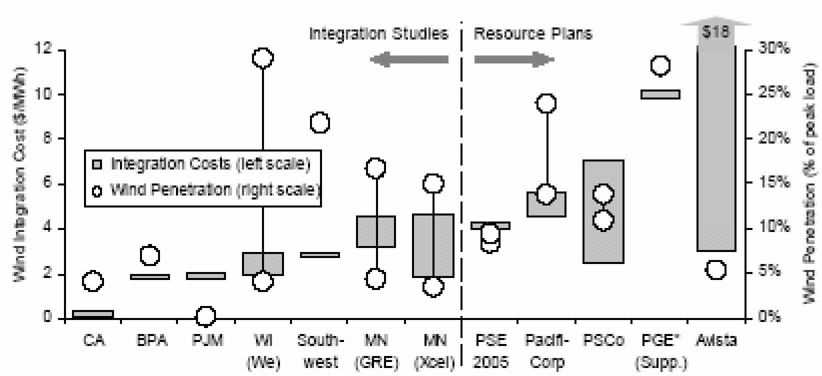


Figure ES-5. Comparison of Integration Costs in Resource Plans and Integration Studies
*PGE estimates the cost of creating a flat, base-load block of power out of variable wind production, rather than simply the cost of integrating variable wind production. As such, its cost estimate is not directly comparable to the others.

Source: *Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans;* Ernesto Orlando Berkeley National Laboratory; Mark Bolinger and Ryan Wiser; August 2005

Representative Transmission Expansion

Proposed Transmission Lines	AssumedYear Complete	Increm. Capacity (MW)	Estimated Total Cost
(Thousands of Nominal Dollars unless otherwise noted)			
TEHACHAPI WIND			
Antelope-Pardee (init. 230 kV)	2008	700	$218,081
Tehachapi -Vincent-Antelope (init. 230)	2008		
PHASE 1 TOTAL (2008)			**$218,081**
New Antelope-Mesa (init. 230 kV)	2010	900	$306,735
PHASE 2 TOTAL (2010)			**$306,735**
New Tehachapi-Vincent (init. 230 kV)	2014	1,700	$1,214,742
PHASE 3 TOTAL (2014)			**$1,214,742**
New Tehachapi-PG&E	2020	1,200	$973,843
PHASE 4 TOTAL (2020)			**$973,843**
PROJECT TOTAL		4,500	**$2,713,401**

Note: TCSG is thinking of recommending no Phase 4 and planning for SCE /SDG&E to take all Tehachapi generation (reducing costs)

IMPERIAL VALLEY GEOTHERMAL			
New Highline-El Centro-IV	2010	645	$84,054
New Midway-Geo	2010		$30,728
New IV-San Diego	2010		$799,385
PHASE 1 TOTAL (2010)			**$1,097,000**
New IID-San Filipe	2016	645	$52,479
Upgrade Bannister-El Centro	2016		$16,147
New Bannister-San Felipe	2016		$49,586
New Geo-Bannister	2016		$13,994
PHASE 2 TOTAL (2016)			**$158,649**
Upgrade Coachella-Devers	2020	910	$25,903
Upgrade Bannister-Coachella Valley	2020		$17,762
Bannister-Geo	2020		$1,688
PHASE 3 TOTAL (2020)			**$64,734**
TOTAL		2,200	**$1,320,383**
N. CALIFORNIA AND NEVADA/OREGON			
Upgrade Donner Pass 115/120 kV	2012	470	$326,806
TOTAL (2012)			**$326,806**
PDCI Line Tap near Gerlach, Nevada	2013	150	$142,081
TOTAL (2013)			**$142,081**
Upgrade Bordertown-Hilltop to Malin	2015	200	$85,714
TOTAL (2015)			**$85,714**
New 500 kV Captain Jack-Olinda-Tracy	2018	1,200	$626,898
ALL N. CAL-NEV/OR PROJECTS TOTAL		2,020	**$1,181,499**

<u>MONO-SAN BERNADINO WIND/GEOTHERMAL</u>			
New Wind/Geo-Mtn. Pass	2009	140	$8,319
New Mtn. Pass 2-El Dorado	2009		$32,389
New Lee Vining-Control	2009		$45,811
New Control-InyoKern	2009		$208,867
TOTAL PHASE 1 (2009)			**$295,387**
New Wind/Geo-Lee Vining	2017	820	$14,532
New Wind/Geo-Mtn. Pass 2	2017		$4,844
New Mtn. Pass 2-El Dorado	2017		$20,778
New Control-InyoKern	2017		$59,275
New Control-Inyo	2017		$7,903
New Kramer-Lugo	2017		$93,566
Loop BLM West-InyoKern	2017		$892
TOTAL PHASE 2 (2017)			**$201,791**
PROJECT TOTAL		960	**$497,178**

Source: CPUC Transmission Plan for Renewables (2003 Dollars)
Note: 1,000 MW of CSP potential estimated for this area

<u>MODOC-SISKIYOU GEOTHERMAL</u>			
Round Mountain	2008	100	$10,899
TOTAL PHASE 1 (2008)			**$10,899**
Cottonwood	2017	195	$25,495
TOTAL PHASE 2 (2017)			**$25,495**
PROJECT TOTAL		295	**$36,393**

Source: CPUC Transmission Plan for Renewables (2003 Dollars)

<u>ALAMEDA-SOLANO WIND</u>			
Substation Upgrades	2005	365	$41,380
TOTAL PHASE 1 (2005)			**$41,380**
New Vaca-Dixon	2008	210	$130,784
			$21,797
TOTAL PHASE 2 (2008)			**$152,581**
Substation upgrades-Alameda Co.	2017	135	$12,747
Substation upgrades-Alameda Co.			$12,747
TOTAL PHASE 3 (2017)			**$25,495**
PROJECT TOTAL		710	**$219,456**

Source: CPUC Transmission Plan for Renewables (2003 Dollars)

POST 2010 TOTAL	**7,625**	**3,846,247**
GRAND TOTAL ALL YEARS	**10,685**	**$5,968,310**

TRANSMISSION AND SYSTEM OPERATIONS CHANGES NEEDED TO SUPPORT ADDITIONAL RENEWABLES

California is blessed with a rich set of renewable resources. However, much of the transmission system and the rules that govern its use were not designed with these resources in mind. Transmission's role in securing renewable resources is to first serve as a collector system from renewable generation plants and then a delivery system to move electrical energy to customers in population centers. Many of California's most important renewable resources are not found within the same areas as the oil and natural gas pipelines, and out-of-state coal resources that were the focus of the design for the collector portion of the system in the past. Often, renewable resources are distant from population centers and in areas that have limited electric transmission facilities. In general, rapid growth of renewable resources is occurring within a transmission system whose design, operating practices, tariffs, and market rules did not fully anticipate their increasing importance.

Accessing California's renewable resources to meet a 33 percent RPS will require expanding transmission capacity, increasing system operational flexibility, and changes to tariffs and rules governing use of the transmission system. Accomplishing this will need the coordinated efforts of the Federal Energy Regulatory Commission (FERC), the California Independent System Operator (ISO), the California Public Utilities Commission (CPUC), and the California Energy Commission (CEC). The following section discusses the roles of these organizations with respect to electric transmission for renewable energy.

Oversight and Management of California's Transmission System

The four organizations mentioned above (FERC, CAISO, CPUC, CEC) have important ongoing roles for electric transmission in California, encompassing economic regulation, planning, siting, development, operations, policy, and research:

<u>The Federal Energy Regulatory Commission</u>

The Federal Energy Regulatory Commission (FERC) regulates rates charged for wholesale sales of power, pricing of transmission services for interstate commerce of wholesale power, electric reliability, and asset transfers, including mergers. FERC has previously asserted that if competitive retail access is in place, it has authority over transmission for retail purposes, suggesting an expanded jurisdiction over use of the electric transmission system. Under Order 888, the FERC has regulatory authority over the tariffs, operations, and transmission planning and expansion process of the California ISO.

With the recent enactment of the Energy Policy Act of 2005, the FERC gained expanded regulatory authority for transmission siting. It will have the authority to designate "national interest transmission corridors." For these corridors, if a state public utility commission withholds permission to construct transmission facilities for more than one year, the FERC will be able to override state authority to issue permits for construction of transmission facilities, including the granting of eminent domain rights.

In 2005, the FERC issued Order 661 (for generators over 20 megawatts) that incorporates a grid code for the interconnection of wind energy (Appendix IV-A). In particular, this grid code helps to facilitate wind energy interconnection by providing equipment and operating standards and by expanding the allowed range of deviation from generation schedules to 10 percent of scheduled energy before penalties are levied. The California ISO expects to make a filing soon to adopt changes prescribed in Order 661. The FERC has also initiated an effort to reform Order 888 to prevent undue discrimination against transmission customers. Order 888 provided a widely-used model for a transmission tariff, containing policies on interconnection and deviation from generation schedules that have proven to be impediments for some renewable generators.

The FERC is important to ensuring adequacy of transmission services for renewable generators in California through its regulation of wholesale power transactions and pricing, transmission services, and its regulatory oversight of the California ISO.

The California ISO

The California ISO was founded in 1996 as part of the restructuring of the California electric utility industry under AB 1890. A nonprofit corporation formed under the auspices of FERC Order 888, the ISO is responsible for independently controlling and operating the electric transmission assets of the three California investor-owned utilities in a reliable and efficient manner. It manages the nondiscriminatory scheduling and delivery of electric power supplies, ensuring all standards for transmission service are met. In addition to its operational responsibilities for the transmission system, the California ISO currently manages markets for transmission service, ancillary services, transmission rights, and a spot energy market. It also conducts a transmission planning process and determines whether or not proposed transmission additions to the ISO control area are cost-effective for ratepayers. This determination of cost-effectiveness is necessary for the California Public Utilities Commission to issue a certificate of public convenience and necessity (CPCN) as part of the certification process for constructing new transmission.

A major initiative of the California ISO is the Market Redesign and Technology Upgrade (MRTU). The California ISO is planning a new market design based upon locational marginal pricing (LMP) for implementation in 2007. The market features will include a reliability-constrained economic dispatch, congestion management based upon economic principles, a spot market, a day-ahead market, a market for congestion revenue rights, and a market for ancillary services.

The California ISO has an important role in the integration of renewable resources into California's transmission system through its responsibilities for transmission planning, transmission operations, electric reliability, market design, and market administration.

The California Public Utilities Commission

The California Public Utilities Commission (CPUC) has regulatory authority over the pricing and provision of retail electric service to consumers by investor-owned utilities. As part of its regulatory jurisdiction, the CPUC has authority over the environmental review, certification, and siting of transmission lines within California. Importantly, it also has authority over the economic regulation of retail revenue requirements of investor-owned utilities, who own roughly 80 percent of the transmission assets in California. Supreme Court rulings have provided authority to FERC in pricing unbundled (wholesale) transmission services, but, because the transmission revenue requirements of investor-owned utilities are recovered by retail pricing, the CPUC can exercise some control. This control is bolstered by the fact that in California, retail load-serving entities pay for transmission access charges (collected by the transmission owners), not generators as is the general practice in other states.

Under California law AB 1890, authority for electric reliability of the transmission system was transferred from the CPUC to the California ISO. The California legislature has since directed the CPUC to mitigate transmission congestion on the California ISO system under AB 970, enacted in 2000, which provides that "the commission, in consultation with the Independent System Operator, shall . . . [i]dentify and undertake those actions necessary to reduce or remove constraints on the state's existing electrical transmission requirements of utilities regulated by the commission" (Public Utilities Code § 399.15). With AB 970, the CPUC received expanded responsibilities for mitigating congestion, thus improving electric reliability. Related to its responsibility under AB 970, in 2000 the CPUC opened an investigation of electric transmission and distribution constraints (OII 00-11-001).

Building upon its prior work on transmission constraints, in September of 2005 the CPUC instituted an investigation into facilitating proactive development of transmission infrastructure to access renewable energy resources (OII 05-09-005). The investigation is assessing how current transmission planning, project development, and cost recovery processes can be modified to facilitate the goals of the renewable portfolio standard (RPS).

The CPUC has an important role in facilitating transmission service for renewable generators through its responsibilities for economic regulation of retail electric service, transmission siting, transmission congestion, and the California renewable portfolio standard.

The California Energy Commission

The California Energy Commission (CEC) was created in 1974 following the Mid-East oil embargo and rapidly rising fuel prices of the previous year. The CEC was initially established to address the many energy challenges facing the state at the time, and to act as the state's primary energy policy and planning organization.

Today, among other responsibilities, the CEC is involved in planning, policy, and research on electric transmission issues. It has the primary responsibility for providing forecasts of electricity demand in California that are important for electric transmission planning and policy decisions. It is engaged in conducting integrated resource planning (including renewables), promoting renewable resources, and long-term planning of transmission infrastructure. The CEC manages the states public interest research (PIER) program that is addressing issues such as intermittent generation, integration of renewable resources, energy storage, and future transmission needs.

The CEC is important to ensuring transmission services for renewables through its forecasting, transmission planning, policy, and research roles.

Summary of Options for Facilitating a 33 % RPS

Table III-1 below summarizes some of the key electric transmission actions that could be taken to facilitate a 33 percent renewable portfolio standard and the agency(s) that could take action to address these issues. Different agencies have different jurisdictional options as well as differing probabilities of success for resolving any particular issue. Some issues may require action by all the agencies listed below while others may only require action by one agency depending upon what turns out to be the most feasible option. Following the table is a discussion of the options.

Table III-1. Electric Transmission Options for Facilitating a 33 Percent RPS

		FERC	CAISO	CPUC	CEC
Expand Transmission Capacity					
	Develop electric transmission capacity for renewables ahead of renewable generator interconnection requests.	✓	✓	✓	
	Adjust the transmission planning and expansion process to better reflect state policy for renewable resources.		✓	✓	✓
	Establish designated transmission corridors		✓	✓	✓
	Form additional stakeholder study groups for transmission projects in important renewable resource areas			✓	✓
	Reduce the risk of developing new transmission facilities	✓		✓	

Increase System Operational Flexibility					
	Evaluate changes to operating practices for existing transmission and hydro assets		✓	✓	✓
	Evaluate whether a mixed portfolio of resource additions by geographic area could reduce system integration costs		✓	✓	✓
	Encourage new transmission technologies that increase system operational flexibility		✓	✓	✓
Increase the Receptiveness of Tariffs and Rules					
	Develop transmission rights and/or congestion revenue rights matched to renewable generator needs.	✓	✓		
	Ensure the compatibility of the California ISO's new market power mitigation rules with intermittent resources.	✓	✓	✓	✓
	Ensure fair and consistent capacity values for renewables within transmission market design and resource adequacy requirements		✓	✓	

Expand Transmission Capacity

Looking beyond 2010, growing renewable energy to 33 percent of California's resource mix will require concerted efforts to increase transmission capacity. Opportunities to increase the availability of transmission capacity for renewable energy center on policy changes on: transmission interconnection, transmission planning, and transmission development.

Developing electric transmission capacity for renewables ahead of renewable generator interconnection requests

Transmission capacity expansion often occurs as the result of an interconnection request from a single prospective generator. After making an interconnection request, a prospective generator is placed in a queue, awaiting the completion of a transmission study to determine the impacts of adding the generator to the transmission system. If the study finds that new transmission facilities or system upgrades are necessary to accommodate the new generator, the new generator must finance part or all of the improvements for a period of 5 years. Later, if the same generator wants to expand their plant and needs more transmission capacity, it must again finance any needed expansion of transmission facilities, even though the expansion may benefit many other transmission customers. Although other transmission customers, including other generators, may ultimately share expansion costs, they do not have to participate in financing the upgrades. No expansions or upgrades to the transmission system to serve new generators are made unless prospective generators request interconnection that necessitates the new transmission facilities. In other words, transmission is not built until the need for it can be proven.

FERC standard interconnection policies were developed primarily to accommodate central station generation projects that were frequently larger than renewable projects. Requiring generators to finance grid upgrades needed to deliver their energy to loads helps ensure that transmission capacity will not be built until it is necessary. However, requiring small renewable generators to finance network upgrades can inhibit implementation of state renewable energy policy.

Current Interconnection Requirements are Inconsistent with the RPS. If the interconnection request of the single renewable generator (the first of several) triggers the need for a new radial transmission line or transmission upgrade, it can make the renewable project too costly. Renewable energy projects are often relatively small (<100 MW) and cannot individually afford to finance the entire cost of an expensive transmission upgrade. This can result in renewable resources not being developed for fear of triggering large transmission costs for the first renewable generator requesting service.

Chicken and Egg Problem: No transmission without a power purchase agreement (PPA) and no PPA without transmission. Generator interconnection requests provide the justification for building transmission to connect new generation. But renewable energy developers cannot execute Power Purchase Agreements (and so request interconnection) if the transmission necessary to deliver their power is not available. Without interconnection requests supported by PPAs for new projects, the transmission to connect them will not be approved.

Unnecessary Costs. Transmission expansion or upgrades made on the piecemeal basis are often not as efficient or cost-effective as they could be. If a new transmission line or substation is to be constructed, economies of scale could substantially lower the unit cost of transmission capacity (and thus the cost to ratepayers), as well as reducing the environmental impacts if the line or substation can be sized to serve many generators instead of a few.

Current transmission expansion rules ignore the modular nature of renewable generation development. It is difficult for renewable generators to join together to request transmission service and split the costs of any needed transmission expansion or upgrades because of uncertainty about receiving contracts and the timing of when that may occur. Unlike conventional fossil plants, renewable generation projects in a particular resource area are likely to be developed over several years rather than all at once. Schedule changes, changes in procurement requirements, and delays to the procurement process can add to this uncertainty. Uncertainty about the timing of contracts and the desire of generators to keep development plans confidential until the interconnection request is made also increases the uncertainty of long-term transmission planning.

Timing mismatch. Once a renewable generator receives a contract and can request transmission service, it may have a very long wait if a new transmission line must be constructed. While renewable generation plants may take from less than one year to a maximum of two years to construct, a transmission line may take four years or more, creating a timing mismatch.

A clear solution for the above issues is building transmission ahead of renewable generator interconnection requests. Probably the most viable funding approach is to establish rolled-in rate treatment for these facilities, paid for by all users of the California ISO grid. This creates risk that ratepayers may pay for facilities that go underutilized, if future renewable generating projects do not materialize. Risks can be reduced by focusing on areas rich in renewable resources and planning the transmission expansions in a modular and phased approach, anticipating the likely pace of development. The CPUC may need to develop mechanisms to minimize this risk and take care to balance this risk against the potentially higher cost that ratepayers could bear from piecemeal transmission upgrades and/or failure to construct sufficient transmission facilities.

Under current policy, radial transmission to connect generating projects located in renewable resource areas is the cost responsibility of the generator, with the first project financing the full cost of the expansion or upgrade for 5 years. Small renewable energy projects often cannot afford such costs. Instead, transmission owners (or merchant transmission companies) should build the required facilities, with renewable generating projects allocated a pro rata share of the costs when they connect. Southern California Edison filed a proposal with the Federal Energy Regulatory Commission (FERC) to create a new class of transmission dedicated to serving renewable resources for which the costs could be rolled into ratebase even if the line is not fully utilized. Though this proposal was rejected, we believe some variation on this concept is necessary to resolve the problem. Other options that are recommended for consideration include:

- Allow transmission lines that are not designated as "network resources" to be placed in distribution system ratebase. The CPUC was given authority to do this by the legislature in establishing the renewable portfolio standard.[55] At present, the CPUC has decided to evaluate this option further as part of its investigation into facilitating proactive development of transmission infrastructure to access renewable energy resources (OII 05-09-005). Exercising this option has the advantage of not requiring approval by the FERC and is being considered for a portion of the transmission needed to access Tehachapi wind resources and may be a good immediate solution to this particular problem. However, applied more broadly, this option has the disadvantage of potentially causing the customers of the transmission-owning utility to unfairly pay for transmission needed by other utilities to comply with the Renewable Portfolio Standard. This is particularly problematic for the customers of Southern California Edison, since they may bear a disproportionate amount of transmission costs. Southern California contains the majority of California's undeveloped renewable resources.

[55] Article 16, California Public Utilities Code 399.11-399.16

- Explore alternatives to Southern California Edison's proposal that may be more acceptable to the FERC. Do not give up on FERC yet. Some organizations commenting on the Southern California Edison proposal were critical of establishing a national policy that adds to their cost of transmission service to support development of renewable resources. Nevertheless, the FERC did not wholly reject the SCE proposal and pushed the boundaries of its previous policy to be more accommodating of renewables. There may be other reasons for the SCE proposal being rejected other than the prima fascia explanation that segment 3 is a radial line and not a "network resource." The CPUC could through informal discussions with the FERC, determine the viability of some revised version of this concept.

- Create state funding support for the transmission facilities necessary to connect large concentrations of renewable resources, through tax-exempt bond or loan guarantee programs. If federal policy cannot be changed to provide rolled-in rate treatment for facilities built in advance of interconnection requests for renewable resources, public funding of transmission expansion could be pursued. This could be accomplished through a California state agency with bonding authority. Some states have formed transmission authorities specifically for this purpose. The funds to retire the tax-exempt bonds could be recovered through grid access fees or usage fees. Alternatively, public resources could be used for loan guarantees to groups of renewable generators in a common renewable resource area to enable the construction of transmission facilities.

- As a last alternative for funding important transmission projects, the California ISO could issue bonds to construct transmission projects for renewable energy identified in the planning process. Current policy states that if a participating transmission owner (PTO) includes projects California ISO believes are necessary, they will be approved. If the PTO does not include projects that California ISO believes are needed, the PTO will have first-right-of-refusal to build the needed project. Otherwise, the project will be offered to private investors. However, offering a project to private investors may not ensure that the needed project will be developed. Presently there are few private investors who seek to own transmission assets embedded in an AC transmission system that others own, control, and establish the pricing for. As a remedy to failing to secure private investors for important projects for renewables on a timely basis, the California ISO could issue tax-exempt bonds to construct new transmission facilities, recovering the costs through ISO transmission access fees. While not typically used for building transmission for renewable resources, this "last resort" mechanism exists in the policies of other regional transmission operators. Finally, this option can be viewed as akin to insurance. If public policy and utility incentives for transmission development for renewables are properly aligned, it is unlikely that this particular option would ever be needed.

- Hold transmission "open seasons" for renewable plant developers. An open season process could help to direct private funding to transmission expansion for renewables. The open season process identifies the future transmission capacity needs of groups of potential users of a prospective transmission line. The process is commonly used for new pipeline development and has been used for some merchant electric transmission line projects. Renewable energy plant developers would participate in a subscription process where they each negotiate and commit to a fixed amount of transmission capacity on the same proposed radial transmission line. In return for financial consideration, the renewable energy developer would receive rights to transmission capacity on the new line. The rights may be resold in the event their renewable generation project does not reach construction.

This process has the benefit of helping the transmission developer to determine the appropriate scale of the transmission project, establish a schedule for development, and plan for financing. For the renewable energy plant developer, there is greater probability that transmission service will become available at a reasonable, shared, cost; improved chances of obtaining a PPA if they do not already have one; improved chances of obtaining debt financing on favorable terms; and improved understanding of the timing and characteristics of the future transmission service. The process would help to better coordinate RPS procurement of renewable resources with development of transmission capacity. The risks for participants in this process can be reduced through performance bonds or insurance for both the renewable energy plant developer and the transmission owner. Such new transmission funding options could help ensure transmission adequacy to meet renewable portfolio standard objectives. However, if rolled-in rate treatment can be achieved, then options such as state-funded transmission for renewables and/or open seasons may be unnecessary.

- <u>Design transmission projects to explicitly qualify as "network upgrades" under FERC transmission expansion policy.</u> This option has the benefit of having greater likelihood of securing rolled-in rate treatment and splitting the costs among all transmission customers. However, a disadvantage is that it may result in higher costs for transmission facilities if transmission lines are unnecessarily extended to connect to distant transmission corridors in order to qualify for "network upgrade" status.

Adjust the Transmission Planning and Expansion Process to Better Reflect State Energy Policy for Renewable Resources

The California ISO recently proposed a new, proactive transmission planning process (August 2005), under which it would identify projects that should be built for economic or reliability reasons. Implementation of state energy policy has not been an objective in the California ISO planning process. Options to consider include:

- <u>Consider adopting state energy policy mandates as criteria in the ISO transmission planning and expansion process</u>. This recommendation would help to ensure long-term planning for transmission for renewable energy. The Electricity Oversight Board and the California ISO Board of Directors could work cooperatively with the CPUC and CEC on modifying the planning and expansion process to better reflect state energy policy.

- Develop new options to help speed renewable energy projects through the transmission queue. Under FERC Order 2003, grouping renewable generator service requests filed within 180 days in the same area will help to advance renewable projects through the transmission queue. However, this may be insufficient, given that the wait in the queue already can take nearly a year. The California ISO could develop options to help speed renewable energy projects selected in a procurement process through the queue ahead of less viable projects. Options include tightening requirements to keep a generator's place in the queue, requiring escalating deposits, or advancing the starting point of renewable generators in the queue that have been selected in the RPS procurement process. Reducing the wait in the queue could reduce development costs and facilitate achieving RPS goals on a timely basis.

- Consider lengthening the conceptual transmission planning horizon. A long-term view in transmission planning is needed to avoid the error of focusing on minimizing short-run costs. The long-term benefits of transmission investment may not begin to accrue for as long as five years and last 30 years or more. Since transmission development can be a long-term process, even a 10-year conceptual plan may not go beyond the immediate transmission development and construction cycle. Assessing transmission needs, costs and benefits for a period of 20 years could be important for accommodating growing amounts of renewable energy.

- Develop predictive performance indicators of transmission expansion for renewables. The CPUC and CEC could identify and report upon key transmission planning and expansion performance indicators and milestones that are predictive of transmission development for renewables. Examples include: 1) the number of certificates of public convenience and necessity issued for renewables-related transmission projects; 2) the amount of land optioned or acquired for transmission right-of-way for renewables; 3) the number of renewable generators in the interconnection and transmission queues; 4) the capacity and timing of renewable transmission projects entering the construction phase; and 5) the results of open seasons for transmission to serve renewable energy projects. Extrapolating the past rate of development forward as done in forecasting RPS performance may lead to inaccurate outlooks given the lumpiness of transmission investment. Transmission development performance indicators may also serve to increase the accuracy of forecasting overall performance on the RPS.

Establish Designated Transmission Corridors.

A major challenge in siting new transmission lines at the time they are needed is obtaining suitable right-of-way. The process of transmission expansion is often fraught with public opposition, competing land uses, and difficulty in acquiring suitable right-of-way. Examining the right-of-way needs for future transmission projects for renewable resource areas, designating and conducting environmental reviews for important corridors, and allowing the banking of necessary lands for right-of-way ahead of interconnection requests could facilitate the process. For prospective acquisition and banking of land for corridors, a mechanism for transmission owners to recover costs on a timely basis would be needed. This would include allowing utilities to retain the costs of right-of-way for transmission corridors in rate base for a period longer than the present 5-year limit.

Form Additional Stakeholder Study Groups for Transmission Projects in Important Renewable Resource Areas.

Study groups have already been formed to evaluate transmission expansion alternatives for the Tehachapi and the Imperial Valley areas. Applying the best practices from these two groups to other renewable resource areas is a good model for gaining the consensus of multiple affected parties and preparing a viable plan for transmission development.

Reduce the Risk of Developing New Transmission Facilities.

Transmission development risks can outweigh rewards for investor-owned utilities**.** Utilities cannot fully recover the costs of new transmission assets until: 1) they are deemed needed by the Public Utilities Commission (Certificate of Public Convenience and Necessity -- CPCN); 2) construction is completed; 3) the facilities remain useful after construction; and 4) they are being used ("used and useful" test). However, public opposition to new transmission lines means many projects never reach the construction stage. Development expenses can include planning, acquiring permits, consultants, labor, environmental-impact studies, acquiring land for right-of-way, public engagement and comment, defense against lawsuits, regulatory proceedings, and cancellation of equipment orders. Some development costs can be expensed and eventually recovered in rates, but these expensed costs do not earn any financial return. Failed transmission projects can cause losses to utility shareholders. In addition to the development risk, there is risk of disallowance and competitive risks. Disallowance risk for transmission owners arises if newly constructed transmission assets are underutilized. In addition, building new transmission can sometimes expose utilities to the risk of greater competition in generation markets, leading to the loss of large customers and stranded generation assets if direct access is once again implemented. Implementing the recommendations below would send a clear signal to utilities that the time to expand transmission capacity has arrived.

- <u>Reduce transmission development risks by ensuring timely recovery of all prudent transmission development costs for renewable transmission projects in retail rates.</u> This would reduce development risks and encourage pursuit of transmission solutions to congestion problems when needed.

- <u>Support the development and rapid implementation of transmission investment incentives as envisioned in the Energy Policy Act of 2005.</u> Examples include accelerated depreciation, an enhanced return on equity, and construction work in progress (CWIP). Enhanced investment returns may aid in the development of new transmission assets in California, benefiting the achievement of renewable portfolio standard objectives.

Increase Operational Flexibility

In every transmission system, some generators must be able to vary their generation output to follow daily and seasonal changes in demand, or load. Transmission system operators need the operational flexibility to dispatch an appropriate amount of generation as load increases, or call upon generators to ramp down their production as load falls. Since electricity is not easily stored, the system operator must continuously balance generation with the load on the system in real time. However, system operators are finding they are increasingly losing operational flexibility. A growing proportion of (fossil-fueled) thermal generators have little ability to be ramped up and down as needed. For example, combined-cycle gas turbines have been designed to maximize fuel efficiency by producing flat "blocks" of generation. They were designed as base load or intermediate units with expected minimum generation at 50 percent of capacity. Their heat rate increases rapidly as generation falls, raising fuel costs. Their start-up costs are between $8,000 and $50,000 per cold start, with a start-up time of up to 6 hours. [56] Excessive ramping can cause increased wear and maintenance time, increase emissions, and can void their turbine warranties. Since the mid-1990s, most new generation capacity added in California has been combined-cycle gas turbines. Nuclear generators cannot be ramped up and down and other generators with modified combustion controls cannot readily be ramped.

The changing mix of thermal generation has resulted in continued reduction of operational flexibility of the grid at a time when it is needed to accommodate increased renewable generation. Wind and solar generators are "intermittent." They may vary their output throughout the day. The limited predictability of intermittent generation can at times create uncertainty for system operators in arranging operating reserves, voltage regulation, and frequency control. Open access transmission tariffs based upon FERC Order 888 often includes strong financial penalties for intermittent generation, discouraging the use of wind and solar resources in some parts of the country. However, suppressing the development of wind and solar generation was not the intent of this part of Order 888. The intent was to promote reliability. Future efforts to promote reliability may benefit from focusing on enhancing and maintaining operational flexibility. Getting more generators with load-following capability into the mix and adopting new grid operating practices could improve operational flexibility and help to achieve the public policy goals for renewable resources.

The California ISO was one of the first transmission system operators in the nation to address intermittency in a constructive way. It designed the Participating Intermittent Resource Program (PIRP) to help intermittent generators avoid these penalties.

---

[56] Makorov, Y., Hawkins, D., "Wind Generation and Grid Operations: Experience and Perspective," Presentation to Participating Intermittent Resources Workshop, March 23, 2005, California Independent System Operator, Folsom, CA.

However, intermittent generators who choose not to join PIRP remain subject to financial penalties for uninstructed deviation from generation schedules and they bear the cost of replacement energy for balancing.

The California Energy Commission has sponsored studies of intermittency-related issues and ways to increase the use of renewable resources in California while maintaining adequate operating flexibility for the transmission system.[57, 58] Many of these studies broke new ground and help to identify promising avenues for further research. A combination of study results and practical experience abroad[59] suggests that changes to system operation and targeted investments in new transmission facilities can accommodate more renewable resources than presently under consideration by California energy policy-makers. For example, the analysis in the Supply Resources section of this report suggests that a 33 percent renewable energy target could be reached in California with a 17 percent wind penetration. Experiences in Europe with renewable resources found that penetrations of up to 20 percent can be accommodated at low cost.[60] Options to increase operational flexibility in California include:

Evaluate changes to operating practices for existing transmission and hydro assets.

Changes to system operating practices and asset management to integrate increased renewable energy may be possible and cost-effective. Studies suggesting potential operational changes and strategic location of renewable generators to facilitate integration into the grid have been completed by the California Energy Commission. The CEC-PIER Intermittency Analysis Project will identify ways to utilize the state's pumped storage and dispatchable resources to increase the operational flexibility of the grid. More broadly, the California Independent System Operator (CAISO) could lead or jointly sponsor studies of potential changes to their system operations, building upon prior work by the CEC and others for integrating more renewables at lower cost. Potential areas of study include:

- <u>Investigate opportunities to better utilize California's hydropower, pumped storage, and demand side management potential to address intermittency issues.</u> Include resources controlled by participating generators in the ISO, publicly-owned utilities, and state water management facilities (See Appendix III-A of this section). California's peak wind generation occurs at night during off-peak loads. If wind generation at night could be used for pumped storage facilities, it would be transformed into dispatchable peaking capability.

---

[57] Consortium of Electric Reliability Technology Solutions, "Assessment of Reliability and Operational Issues for Integration of Renewable Generation," California Energy Commission, 2005.
[58] "Strategic Value Analysis: Integrating Renewable Technologies in Meeting Target Renewable Penetration," Public Interest Energy Research, California Energy Commission, 2005.
[59] ABB Electric Systems Consulting, "Integration of Wind Energy Into the Alberta Electric System," Raleigh, North Carolina, 2004.
[60] KEMA-XENERGY, "Intermittent Wind Generation: Summary Report of Impacts on Grid System Operations, June 1, 2004, CEC 500-04-091.

- Investigate opportunities to increase the utilization of existing transmission infrastructure. Investigate methods to better manage unused non-firm capacity on existing transmission paths (e.g. Path 15, Path 26, COB, and COI) for increased in-state renewable generation and out-of-state renewable energy imports. The implementation of the new LMP market design by the California ISO may contribute to improved utilization of transmission assets. However, reliability and other issues unrelated to market design also affect utilization of key transmission paths. Further, not all transmission assets important to California are under ISO control. The study would look at all transmission assets in the state, encompassing California's public and investor-owned transmission systems and transmission paths important for importing renewable energy, irrespective of grid ownership.

If these studies conclude that changes to operations and asset management could facilitate renewable energy integration at lower cost the changes may, in some cases, need to be phased in over time as contracts for existing uses of the assets expire or are purchased.

Evaluate whether a mixed portfolio of resource additions by area could reduce system integration costs

Where resources permit, balancing the proportion of solar, geothermal, and biomass resources relative to wind may create better coincidence with peak loads, helping to reduce requirements for transmission investment, ancillary services, and operating reserves. This option could be investigated by the CPUC, CEC, ISO, and transmission study groups.

An important part of California's generation resource portfolio is generation with load-following capability. Recognizing the value of load-following capability of fossil plants in relation to renewable energy and the grid as a whole is important in integrated resource planning and regulatory cost recovery proceedings. Load following capability is often associated with higher heat rates and lower fuel efficiency for thermal generators. Most commonly, these generating resources are simple-cycle combustion turbines. Individually, these generators may not look cost competitive. However, in combination with renewable resources they may help to achieve a lower system cost, improved reliability and greater operational flexibility.

Encourage new transmission technologies that increase system operational flexibility.

Through favorable regulatory treatment, the California Public Utilities Commission can encourage investigation and adoption of new transmission and energy storage technologies that will increase the operational flexibility and efficient utilization of the grid for renewable resources. Examples of favorable regulatory treatment include accelerated depreciation or an enhanced return on equity, either fixed or performance-based. The CPUC has recently begun to investigate new transmission technologies. Potential technologies of interest include:

- Flexible AC Transmission Systems (FACTS). This is a group of technologies that allow delivery of increased power over existing facilities without threatening reliability. These power electronics devices are usually deployed as an alternative to building new transmission lines. The equipment typically consists of series compensators, shunt compensators, or both that act as a controllable voltage source.
- Superconducting Magnetic Energy Storage (SMES). SMES devices could be strategically located in a transmission grid to dampen out disturbances. SMES systems use a cryogenic technology to store energy by circulating current in a super-conducting coil, advanced line-monitoring equipment to detect voltage deviations, and inverters that can rapidly inject the appropriate combination of real and reactive power to counteract voltage problems. By correcting for potential stability problems, these systems permit the operation of transmission lines at capacities much closer to their thermal limits than now possible.
- Advanced Conductors. Usually transmission lines contain steel-core cables that support wrapped strands of aluminum wires which are the primary conductors of the electricity. New cores and wires developed from composite materials and alloys are stronger and lighter, sometimes allowing more than twice as much power through transmission lines.
- Energy Storage. Compressed air storage and flywheel systems are being evaluated in other countries for use with renewable energy. Many European countries envision that some type of energy storage system will be required as the percentage of intermittent resources in their resource mix continues to grow. If cost-effective energy storage options could store energy off-peak to later inject it on-peak, it could help grid operational flexibility and raise the value of the energy.
- Wide-area Communications Network and System Monitoring. Improved communication and control equipment would allow system operators to anticipate and correct problems earlier and enable operating the system within tighter limits.
- Dynamic Thermal Circuit (Line) Rating: While still being perfected, software is available to provide operators and engineers with line ratings in real time. Development of on-line dynamic security assessment tools, operator security indices and pre-determined operator preventive and corrective actions could also help operate transmission lines closer to their thermal ratings.

Increase The Receptiveness of Tariffs and Rules

California's transmission tariffs and market rules are more advanced than many states in accommodating renewable energy. For example, transmission access charges are levied on load-serving entities, not generators. The participating intermittent resource program provides a mechanism for renewable generators to avoid penalties for not being able to follow fixed generation schedules. Yet, there are still areas where changes may be needed to facilitate renewable generation.

The California ISO is planning a new market design based upon locational marginal pricing (LMP) for implementation in 2007. The market features will include a reliability-constrained economic dispatch, congestion management based upon economic principles, a spot market, a day-ahead market, a market for congestion revenue rights, and markets for ancillary services.

Develop transmission rights and/or congestion revenue rights better matched to renewable generator needs.

In transmission tariffs, fees for service tend to be based upon either the amount of transmission capacity at peak usage (capacity-based) or upon total volume of generation over a fixed period of time (volume-based). The capacity-based fees create problems for intermittent generation, particularly wind and solar. The natural variability of intermittent generation means that a generator sometimes reaches its peak capacity, but the average amount of generation is often less than half of its nameplate generating capacity. Meanwhile, a thermal generator may achieve a generation capacity factor of 80 percent of total capacity over the same time period. If transmission customers are paying for transmission services based upon transmission capacity reserved, the renewable generator's cost per Mwh of the transmission service would be more than twice that of the thermal generator. The wind generator's low generation capacity factor makes it unable to use most of the reserved transmission capacity. Nevertheless, a transmission customer must pay for both the used and unused transmission capacity. The natural operating characteristics of wind and solar generators make firm transmission rights and congestion revenue rights (under the new market design) less cost-effective. New ways to price these rights could increase their usefulness to wind and solar generation.

- <u>Consider volumetric charges or other approaches to pricing congestion revenue rights that are not driven by capacity-based pricing</u>. Predicting generation with accuracy is important to efficiently hedge congestion costs with congestion revenue rights in the new market design, potentially creating difficulties for intermittent generation. Charges based upon volume of usage may alleviate this problem.

- <u>Develop new long-term versions of congestion revenue rights</u>. A one-year term for these rights means that there is uncertainty about the long-term cost of delivering the renewable energy when seeking long-term debt financing. This raises the cost of debt and ultimately, the cost of the renewable energy. An extended term for the rights could lower barriers to obtaining debt financing for renewable generators.

Ensure the compatibility of the California ISO's new market rules with intermittent resources.

The new market design in 2007 will play a key role in the viability of wind and solar resources in California well beyond 2010. This is a critical time to work with the

California ISO to ensure that intermittent resources are not disadvantaged in the new market design.

- Maintain the availability and benefits of the participating intermittent resource program (PIRP) in the new market design based upon locational marginal pricing (LMP). Balancing costs and uninstructed deviation penalties can be devastating for wind and solar generators. While the California ISO proposed changes to PIRP in September 2005, at the time of writing, no decision has been made.

- Create appropriate exceptions for intermittent generators in new market mechanisms designed to mitigate market power. Following the California energy crisis and charges of market manipulation, many market designs in other regions have incorporated mechanisms to limit the market power of generators. While these mechanisms are not specifically aimed at renewable generators, they can negatively impact them. Intermittent renewable generators are often too small to have significant market power and may need to be exempted from some market power mitigation tools such as must-offer rules and outage reporting requirements, unless they are explicitly adjusted to take intermittency into account. Intermittency makes compliance with these mechanisms onerous and could potentially lead to unwarranted suspicion of economic withholding when declining generation is caused by natural variations in the wind or the sun.

Ensure fair and consistent capacity values for renewables within transmission market design and resource adequacy requirements.

Adopting a fair and consistent methodology for calculating capacity values for a future capacity market and for resource adequacy requirements is important to avoid discrimination against future renewable resource development. Initially, the California ISO's new market design will not include a capacity market. However, it is expected that one may be implemented in the near future. If a consistent and fair methodology for establishing capacity values for renewable generators in California is not established, it could reduce future development of renewable generation. The CPUC is presently establishing capacity values for renewable generation for use in meeting the resource adequacy requirement. This is an important step. Ideally, potential future investors in renewable generation will perceive value for renewables in both meeting resource adequacy requirements and in a future capacity market.

PJM Interconnection in the Northeast awards capacity values to wind generators based upon a rolling 3-year average of actual generation during peak demand hours, averaging 20 percent across the entire class of wind generators. Calculating renewable energy capacity values based upon average historical operating characteristics or upon the probability of operation at the time of peak are both used in other regions. Geographic or spatial diversity of wind generator locations reduces total wind output variability, since varying wind patterns tend to cancel each other out. This can improve capacity values and suggests that balancing requirements will not increase linearly with growth in wind generation capacity.

Conclusion

Electric transmission will play a critical role in expanding the use of renewable resources in California. Removing unintended obstacles to developing new transmission capacity for renewable resources, increasing the operational flexibility of the grid to accommodate growth in renewable generation, and removing transmission tariff and non-tariff barriers to developing renewable resources are all three necessary to achieving important public policy objectives for renewable energy.

References

(1) Swisher, Randall, "Bringing Wind Energy Up to Code," Public Utilities Fortnightly, June 2004.

(2) KEMA-Xenergy, "Preliminary Stakeholder Evaluation of the California Renewables Portfolio Standard," California Energy Commission, CEC-300-2005-011, June 2005.

(3) ABB Electric Systems Consulting, "Integration of Wind Energy Into the Alberta Electric System," Raleigh, North Carolina, 2004.

(4) "Upgrading California's Electric Transmission System: Issues and Actions for 2005 and Beyond," Staff Report in Support of the *2005 Integrated Energy Policy Report* Proceeding (04-IEP-1F), CEC 700-2005-018, California Energy Commission, July 2005

(5) Davis Power Consultants, PowerWorld Corporation, Anthony Engineering, "Strategic Value Analysis for Integrating Technologies in Meeting Target Renewable Penetration in Support of the 2005 Integrated Energy Policy Report," California Energy Commission, CEC-500-2005-106, Public Interest Energy Research Program, June 2005.

(6) Senate Bill No. 1078, Chapter 516, An act to add Sections 387, 390.1, and 399.25 to, and to add Article 16 (commencing with Section 399.11) to Chapter 2.3 of Part 1 of Division 1 of, the Public Utilities Code, relating to renewable energy. September 2002.

(7) "California ISO Planning Standards," The California ISO, February 7, 2002, Folsom, CA.

(8) Integrated Energy Policy Report Committee, " Strategic Transmission Investment Plan," Prepared in Support of the 2005 Integrated Energy Policy Report Proceeding (04-IEP-1K), Draft Committee Report, California Energy Commission, CEC 100-2005-006-CTD, September 2005

(9) Mohamed Awad, Steven Broad, Keith E. Casey, Jing Chen, Anna S. Geevarghese,

Jeffrey C. Miller, Anjali Y. Sheffrin, Mingxia Zhang, Eric Toolson, Glenn Drayton, A. Farrokh Rahimi, *S.M., IEEE,* and Benjamin F. Hobbs, *S.M., IEEE,* "The California ISO Transmission Economic Assessment Methodology," Conference Paper for Electricity Transmission in Deregulated Markets: Challenges, Opportunities, and Necessary R&D Agenda , Carnegie Mellon University, EPRI, and the US National Science Foundation, December 15-16, 2004. Pittsburgh, PA.

(10) Consortium of Electric Reliability Technology Solutions, "Planning for California's Future Transmission Grid: Review of Transmission System, Strategic Benefits, Planning Issues, and Policy Recommendations," California Energy Commission, 700-03-009, October 2003.

(11) Western Governors Association, Transmission Finance Committee, "Financing Transmission Expansion in the West, Appendix 1: Transmission Expansion Process" February 2002.

(12) Center for Resource Solutions, Davis Power Consultants, Electranix, Kema-Xenergy "Renewable Energy and Electric Transmission Strategic Integration and Planning, Inter-state Generation and Delivery of Renewable Resources into California from WECC States," California Energy Commission, May 2005.

(13) **Regional Transmission Projects: Finding Solutions**, A Report by The Keystone Center, June 2005

(14) Federal Energy Regulatory Commission, Docket No. RM05-4-000 – Order No. 661, "Interconnection for Wind Energy," 111 FERC ¶ 61,353, 18 CFR Part 35, June 2, 2005.

(15) SB 1038/Public Utilities Code Section 383.6: "Electric Transmission Plan for Renewable Resources in California," California Public Utilities Commission Energy Division, December 1, 2003.

(16) Consortium of Electric Reliability Technology Solutions, Electric Power Group, "Assessment of Reliability and Operational Issues for Integration of Renewable Generation," In Support of the California Energy Commission *2005 Integrated Energy Policy Report* , California Energy Commission, 2005.

(17) Doughman, Pamela, "Renewable Resources: Status, Issues, Options, Questions," Presentation to IEPR Committee Workshop on California's Loading Order for Electricity Resources, July 21, 2005.

(18) Hirst, Eric, "US Transmission Capacity: Present Status and Future Prospects," Edison Electric Institute, June 2004.

(19) "Implementing California's Loading Order for Electricity Resources," Staff Report, California Energy Commission, CEC-400-2005-043, July 2005.

(20) Makorov, Y., Hawkins, D., “Wind Generation and Grid Operations: Experience and Perspective,” Presentation to Participating Intermittent Resources Workshop, March 23, 2005, California Independent System Operator, Folsom, CA

(21) Federal Energy Regulatory Commission, EL05-80-000, 112 FERC ¶ 61,014, Southern California Edison Company, Order on Petition for Declaratory Order, July 1, 2005.

(22) KEMA-Xenergy, “Intermittent Wind Generation: Summary Report of Impacts on Grid System Operations,” California Energy Commission, 500-04-091, June 1, 2004.

(23) The Transmission Access Policy Study Group, “Post-Technical Conference Comments,” Before the Federal Energy Regulatory Commission, Dockets No. PL04-15-000, Interconnection of Wind Energy and Other Alternative Technologies, RM02-12-000, Interconnection Agreements and Procedures, RM02-1-001 and RM02-1-005, Standardizing Generator Interconnection Agreements and Procedures, November 1, 2004.

Interviews/Telephone Discussions:

Mr. James Blatchford, Account Manager, Participating Intermittent Resource Program (PIRP), The California ISO, August 2005.

Mr. Patrick Wood III, Former Chairman, Federal Energy Regulatory Commission, September 1, 2005.

Mr.Yakout Mansour, President & Chief Executive Officer, The California ISO, September 1, 2005.

Mr. Robert Gramlich, Director, Policy, American Wind Energy Association, September 6, 2005.

Mr. Steve Metague, Director, Electric Transmission Rates, Pacific Gas and Electric Company, October 19, 2005.

APPENDIX III-A

USING WESTERN HYDRO RESOURCES TO ENHANCE RENEWBALE ENERGY INTEGRATION OPPORTUNITIES

Developing a Regional Strategy to Integrate the Operation of Hydro and Wind

From the earliest days of wind energy deployment in California, energy planners have postulated the potential synergies and benefits associated with integrating, from an overall system standpoint, the operation of wind and hydroelectric power. Wind and hydro power have naturally complimentary characteristics (wind energy being predictable and reliable on an annual basis, but with little hourly capacity value and no dispatchability; while hydro has extreme annual energy fluctuation, but with storage a fundamental part of the system it has a high degree of dispatchability and capacity value). While the overall quantity of wind on the west coast electric system has remained small (approximately 3500 MW) relative to the overall system size (70,000 MW), the subject has largely remained only of academic interest.

However, the vast wind resource present in California, Oregon and Washington, and the current interest in expanding wind deployment in those states by up to a factor of 5, has compelled many to examine the wind-hydro integration opportunity in more depth.

Bonneville Power Administration has already developed a Storage and Shaping Service for wind, using its hydro assets on the Columbia River to provide this. This service is available to California Utilities, and several have availed themselves of this. California has a hydroelectric resource comparable in size to the Pacific Northwest. While much of California's hydro lacks the operational flexibility of the Columbia River system, there are many plants that can provide the storage and shaping service that Bonneville has developed.

Through the operation of the Pacific AC and DC Interties, there has been a long history of California and the Pacific Northwest cooperating on a mutually beneficial basis to exchange large quantities of energy and capacity to serve radically different load profiles. The existing hydro and interconnecting transmission assets across the west can be further exploited to increase the quantity of low cost intermittent wind that can be accommodated on the western grid. California, Oregon and Washington, including the utilities and control area operators, should examine the extent of the potential benefits of developing a regional approach to wind-hydro integration.

Hydro Re-dispatch Issues and Impediments

Re-dispatching hydroelectric generation to firm up the intermittent generation of power from wind or other renewable energy resources is a relatively new issue that has not been embedded into operating strategies and procedures. The Bonneville Power Administration (BPA) has undertaken and study to evaluate the costs and opportunities associated with integrating wind energy into the Federal Columbia River Hydroelectric System (FCRPS). In March 2004, BPA announced two new services. These are; the Network Integration Service and the Storage and Shaping Service.

The Network Integration Service will be charged to customers in the BPA Control Area at a fee of $4.50/MWh (subject to annual escalation).

The Storage and Shaping Service is designed to serve the needs of utilities and other entities outside the BPA Control Area who have chosen to purchase the output of a new wind resource but do not want to manage the hour-to-hour intermittency associated with wind. To facilitate the service, BPA's Power Business Line will take the hourly output of new wind projects into the BPA Control Area, integrate and store the energy in the Federal hydro system, and re-deliver it a week later in flat peak and off-peak blocks of power to the purchasing customer. To help reduce transmission costs, return energy will be capped at 50 percent of the participant's share of project capacity. The base charge for storage and shaping service is $6.00/MWh, escalated annually at the GDP Implicit Price Deflator.

BPA's Storage and Shaping Service is illustrated in Figure 25. This service is an example of what might be applied to the Federal Hydro system in California, as well as the Feather River, Hetch Hetchy, Pit River and Colorado River hydro systems. It is recognized that management of water with these hydro systems are less flexible than the FCRPS due to constraints imposed by water use for irrigation, fishing and recreation. Nevertheless, each hydro system should be investigated to see what energy storage and release services might be possible, and what fees might apply for it to be profitable for all concerned. Such studies and recommendations could be completed by 2010.

The ability of existing hydroelectric plants to be used to firm or shape intermittent renewable energy may be more or less depending on the flexibility available to re-schedule water release, the water storage capacity of reservoirs and whether or not the river system is in flood. For run-of-the-river plants there may be no firming capability available because of limited reservoir capacity.

An initial screening of western hydroelectric facilities has been made to identify those that could plausibly be used for the purposed outlined above. These are listed in Figure III-A-1.

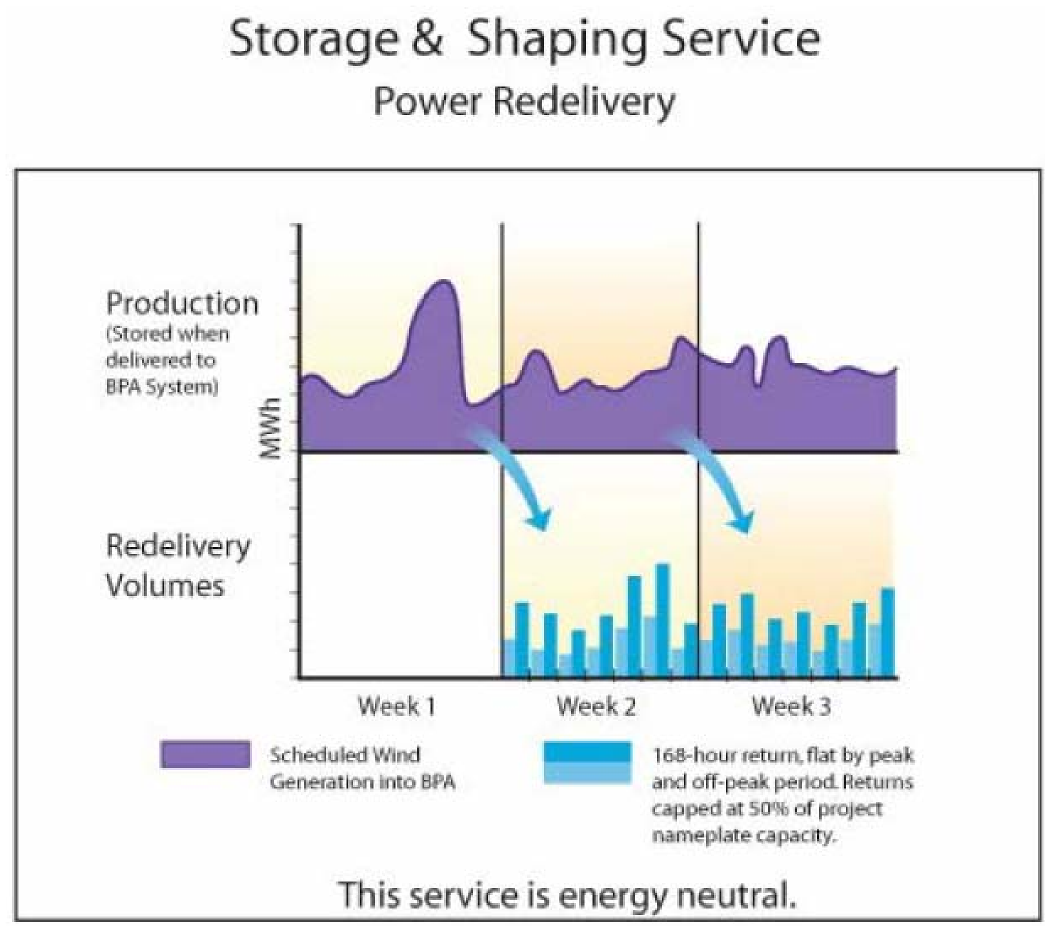


Figure III-A-1: BPA's wind energy Storage and Shaping Service
Source:
http://www.bpa.gov/Power/PGC/wind/BPA_Wind_Integration_Services.pdf

Source: Renewable Energy and Electric Transmission Strategic Integration and Planning: Inter-state Generation and Delivery of Renewable Resources into California from WECC States, Consultant Report in support of the 2005 IEPR– May 2005
Center for Resource Solutions; Davis Power Consultants; Electranix; Weiser Associates

Table III-A-1
Western Hydroelectric Generating Plants

Hydroelectric System	**Capacity (MW)**
Pit River & James E. Black	682
Federal Hydro (Keswick, Judge Francis Car, Trinity, Spring Ck, Shasta)	1,250
Tuolumne (SFCPUC - Moccasin, Kirkwood, Holm), Don Pedro, New Melones)	852
SMUD plants	710
Feather River (Butt, Bucks, Cresta, Caribou, Rock, Belden, Poe, Thermalito, Hyatt)	718
Mokelumne River (Hydro Project 1, Collierville)	502
Big Creek (Big Creek, Mammoth Pool)	804
King River (King River, Pine Flat, Kerchoff2 Haas)	516
Upper Columbia River (Grand Coulee, Chief Joseph)	8,563
Hoover Dam	2,074
Total	16,671

APPENDIX III-B

TRANSMISSION ISSUES FOR NON-ISO MEMBERS

The focus of appendix B is upon facilitating renewable generation for use in California that originates outside the California ISO control area or from other states. Meeting a 33 percent renewable portfolio standard would more readily be achieved by expanding the range of renewable resource areas able to supply California customers. While the vast majority of California's electric transmission assets are contained within the California ISO control area, there are important California renewable resource areas that are served by non-ISO public utilities. In addition, there are important renewable resources capable of serving California customers that are located out-of-state.

Renewable Generation Outside the California ISO Control Area

California may want to encourage renewable generation in control areas and utility service areas that are within California, yet outside the California ISO. In addition, it may also want to seek to facilitate renewable energy imports from outside California.

- Public utilities in California who are not part of the California ISO are often dependent on using the extensive ISO transmission system. The policies and tariffs of the ISO for non-member utilities can have a profound impact upon the ability of these utilities to host renewable generators within their service areas.

- When California load-serving entities (LSEs) purchase renewable energy from a generator outside the state, the energy may need to pass through the transmission systems of several different utilities, with the renewable generator or LSEs paying the grid access charges of each along the way. These grid access charges to recover fixed costs stack up upon each other like pancakes, giving rise to the term "rate pancaking." Rate pancaking can substantially increase the costs of transmission for long-distance transactions, often making them uneconomic.

- The transmission tariffs of some western control areas outside California continue to offer firm transmission service with capacity-based fees and financial penalties for deviation from generation schedules. This disadvantages wind and solar generators and makes them less able to export renewable energy to California.

Recommendations

<u>The California ISO should avoid policies creating disincentives for hosting renewable energy generators in California outside the California ISO control area.</u>

This recommendation is particularly important for California's public utilities dependent upon the California ISO for transmission services. In general, California control areas or transmission dependent utilities outside the ISO might be offered extended terms consistent with the California ISO Participating Intermittent Resource Program (PIRP) for the amount of energy in the interchange sourced from intermittent renewable generators. Similar to Bonneville Power Administration and PacifiCorp, balancing charges for renewable energy should be cost-based, without penalties. For example, the Sacramento Municipal Utility District (SMUD) has left the California ISO but wishes to continue to take part in the ISO Participating Intermittent Resources Program. Absent the ability to do so, it would be subject to heavy ISO financial penalties for intermittent generation from the 15 MW of wind capacity within SMUD service area.

Cooperate with regional transmission service providers to create a through-and-out-rate for wheeling renewable energy (CAISO).

A regional through-and-out rate could be defined to facilitate renewable energy transfers into California. This would avoid pancaking of fixed cost charges, making transfers more economic. It would require negotiating with other transmission owners to establish a mechanism to redistribute fees for fixed costs.

Encourage the development of "priority non-firm" or "conditional firm" transmission service in neighboring states (CAISO/FERC)/CPUC).

Current firm transmission service leads to underutilization of existing transmission assets and is often unnecessary and costly for renewable generators. To better utilize the system, take into account the dynamic nature of load patterns and generation patterns and the resultant scale and timing of path constraints to make increased transmission capacity available to renewable generators, lowering costs.

COST AND RATE IMPACTS OF VARIOUS 33 % RPS SCENARIOS

Approach

This analysis addresses the overall cost impact of a 33percent RPS and its effects on the average rates of the three largest California investor owned utilities, PG&E, SCE and SDG&E. The incremental costs of the 33 percent RPS are calculated by comparing the projected procurement costs of the RPS, including any incremental transmission and wind integration costs (the *33 Percent Renewable Base Case Scenario*), to a projection of the otherwise applicable costs the IOUs would incur to purchase the same amount of energy at market prices. These otherwise applicable costs are characterized in a business as usual (BAU) rate scenario that assumes that the current 20 percent RPS is achieved by 2010, and that energy procurements that are displaced by the 21-33 percent RPS procurements are from generation resources purchased at market prices. The differential between these two cost projections is the cost impact of the 33 percent RPS. Rate impacts are calculated by developing a long term projection of retail rates without the 33 percent RPS (including only a 20 percent RPS), multiplying these rates by a load forecast to derive total revenues collected by rates, and then dividing the cost impact of the 33 percent RPS by this total.

Total RPS cost = Total Delivered Energy Cost of RPS Renewables – Otherwise Applicable Cost of Market Procurements

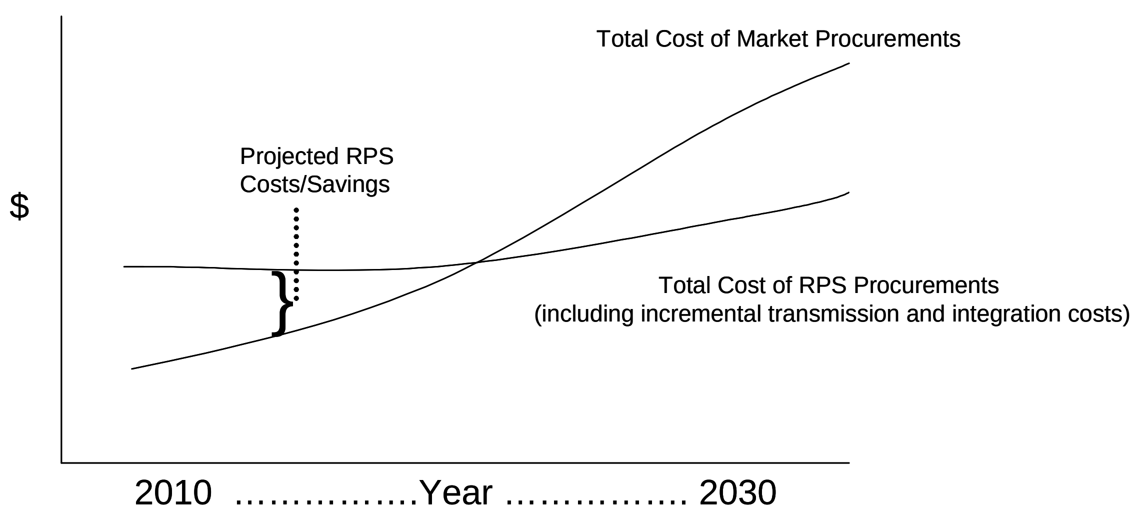


Figure IV-1. Analytic Approach-Comparing RPS Costs with Market Procurements

Market Procurements Forecast: Electricity Market Price and Natural Gas Price Forecasts

The forecast of electricity market prices in each year was developed using the methodology adopted by the CPUC to calculate avoided costs.[61] This methodology assumes that market prices in the post 2010 time frame will be equal to the cost of electricity produced by a new natural gas combine cycle combustion turbine. This method of forecasting market prices is highly dependent upon the natural gas price forecast that is an input into the CPUC methodology.

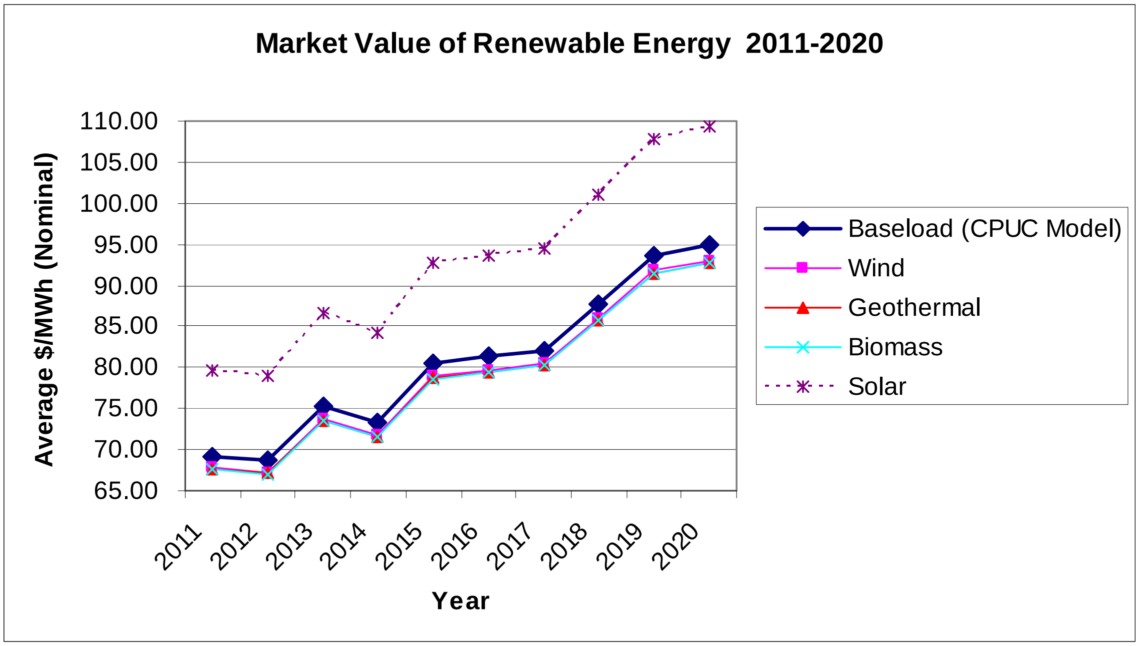
For this analysis, the natural gas price forecast was updated from what was used earlier this year by the CPUC to reflect the most recent natural gas price forecast available for California generators. This is the natural gas price forecast developed for the 2005 CEC IEPR proceeding (see Market Price Forecast Section of Appendix IV-A). Although there is much uncertainty surrounding the development of a 25 year natural gas price forecast, we believe that the forecast used in this analysis is conservative. At the time this analysis was done, current natural gas NYMEX futures prices for the next year period range from $10-$14/MMBtu.[62] The natural gas price forecast used in this analysis does not reach a nominal price of $10/MMbtu until the year 2019, and does not reach $14/MMBtu until 2026.

The CPUC methodology used to calculate market prices includes a function to develop market prices by time of delivery (TOD). This analysis used the TOD factors in the CPUC methodology to develop market price forecasts that fit the production profiles of each of the renewable resource types assumed for the 33 percent RPS case. The market price forecasts represent the market value of the renewable energy sources purchased for the RPS, and the analysis assumes that the utilities will pay these prices for market energy in the BAU scenario. Figure IV-2 below illustrates the resulting market price forecasts for each renewable energy technology. (See Appendix IV-A for a description of the TOD assumptions.)

---

[61] CPUC D.05-04-024, April 7, 2005. This decision adopted a report by Energy and Environmental Economics (E3), entitled Methodology and Forecast of Long-Term Avoided Cost(s) for the Evaluation of California Energy Efficiency Programs (Final Report). The worksheets implementing this methodology can be downloaded at: http://ethree.com/cpuc_avoidedcosts.html.
[62] Unless otherwise noted, all figures are in nominal dollars.

Figure IV-2. Market Value of Renewable Energy (2011-2020)



RPS Procurement Forecast

<u>Quantity of RPS Renewables:</u> Forecasts of the portfolio of renewables used to meet the RPS requirements in each year between 2011 and 2020 are described in *Summary of Existing Technical Information on Existing and Potential Renewable Sources*. The RPS procurement requirements described in that report are based on utility load forecasts submitted to the CEC for each of the utility's planning areas. Planning area data include loads that will not be part of the IOU RPS procurements, including some loads served by public power entities. This cost and rate analysis is focused on the IOU RPS obligations. Hence, for the purpose of calculating the RPS procurement requirements for the IOUs in this analysis, we base the RPS procurements on a load forecast strictly for IOU loads. This load forecast was developed by taking estimates of current IOUs loads (190,080 GWh in 2006), and escalating them at 2 percent per year through the analysis period. The combined load forecast for the three IOUs by year is listed in Appendix IV-A. Table 3-1 below lists the incremental RPS procurements by resource type for the three IOUs. The resource mix of the portfolio of RPS procurements are as described in Section III - *Summary of Existing Technical Information on Existing and Potential Renewable Sources.*

Table IV-1. Incremental Annual Energy Procurement for PG&E, SCE and SDG&E (2011-2020)

Incremental Energy Procurement (GWh)

Year	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Wind	1776	1838	1903	1969	2038	2108	2180	2255	2331	2410
Geothermal	1065	1103	1142	1182	1223	1265	1308	1353	1399	1446
Biomass	355	368	381	394	408	422	436	451	466	482
Solar	355	368	381	394	408	422	436	451	466	482
PV	0	0	0	0	0	0	0	0	0	0
Total	3551	3677	3806	3939	4076	4216	4361	4509	4662	4819

Price of RPS Renewables: This analysis assumes that the contracted price of renewables is equal to the price projections developed in *Summary of Existing Technical Information on Existing and Potential Renewable Sources*. The *33 Percent Renewables Base Case* prices are reproduced in Table IV-2 below. These prices are in nominal dollars, and the analysis assumes that the nominal price of new renewable energy procurements remains constant between 2011 and 2020.

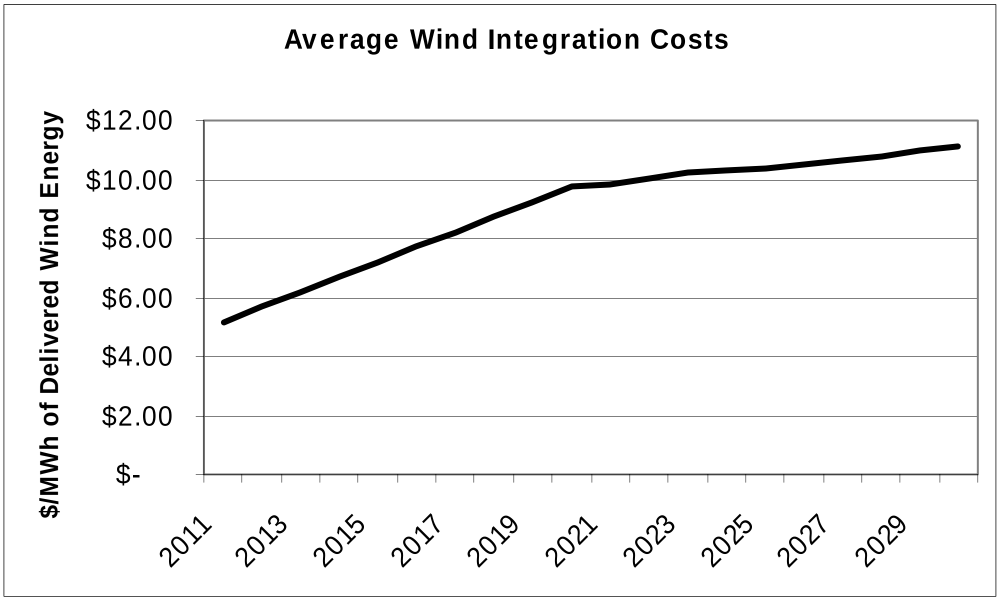
Table IV-2. 33 Percent Renewables Base Case Incremental Energy Price- No PTC or ITC

Resource	$/MWh (nominal)
Wind	$66
Geothermal	$86
Biomass	$78
Solar	$120
PV	$200

Once a renewable energy generator is contracted for the RPS, this analysis assumes that the generator remains under contract at a fixed price for the entire analysis period. The renewable energy price data presented in the *33 Percent Renewables Base Case* cost analysis assumes that the Production Tax Credit (PTC) and Investment Tax Credit (ITC) will not be in effect for the post 2010 period.

Integration Costs: In addition to the renewable energy procurement costs above, integration costs associated with the use of intermittent wind energy are added to the projection of RPS costs. These costs are also described in Section II *Summary of Existing Technical Information on Existing and Potential Renewable Sources.* Figure IV-3 below summarizes the integration cost added per MWh of delivered wind energy for the analysis period. Detailed descriptions of the assumption used to develop these costs are included in the Appendix IV-A.

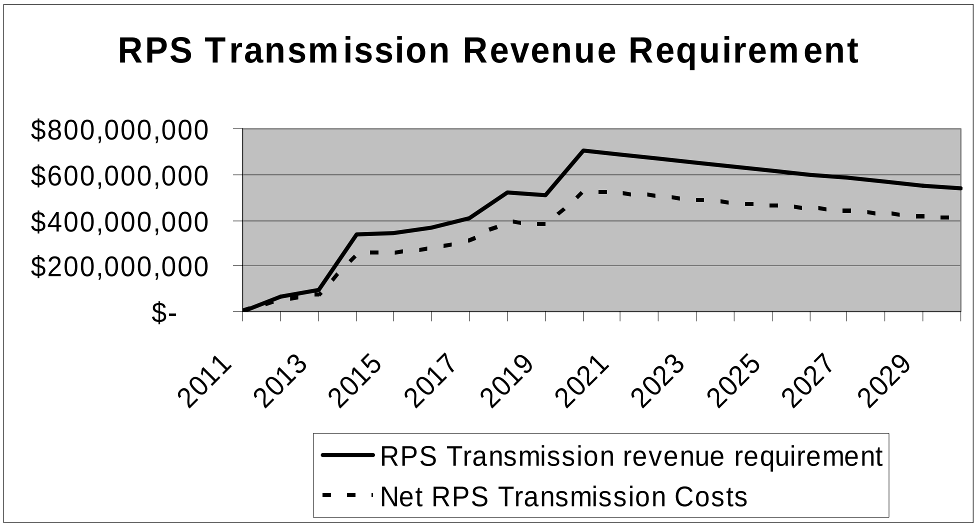
Figure IV-3. Integration Costs for Wind Energy



Transmission Costs: The costs of incremental transmission investments for the RPS renewable facilities in California, as described in Section 3, were also added to the renewables cost projection.[63] For the *33 Percent Renewables Base Case* analysis, it was assumed that 75 percent of the transmission revenue requirement from these new transmission investments would be assigned to the RPS. The analysis uses a simple transmission revenue requirement model to develop a revenue requirement forecast for incremental transmission costs attributable to the RPS. The Figure IV-4 below summarizes the transmission costs used in the *33 Percent Renewables Base Case* analysis. As shown in the chart, the Net RPS Transmission Costs are 75 percent of the total transmission revenue requirement of the proposed incremental transmission investments needed to meet the 33 percent target.

[63] In developing the forecast of utility rates without the 33 percent RPS, we considered current and historical utility transmission costs, and do not include in any extra incremental transmission costs for new transmission to deliver non-renewable electricity from the interior-West.

Figure IV-4. Transmission Revenue Requirement Attributable to 33 Percent RPS



Rate and Load Forecast

The sections above describe how the total net revenue impact of the RPS is developed by evaluating the difference between the cost of market procurements and the cost of the RPS procurements. To evaluate the average statewide rate impact, the analysis divided the total net revenue impact of the RPS procurement in each year by the total revenue requirement of the three IOUs. Total utility revenue requirement was developed by developing a projection of the average IOU rate for the analysis period, and multiplying that rate by a load forecast. We developed rate forecasts for PG&E and SCE for the analysis period, and assumed that the statewide average IOU rate would be equal to the load weighted average for these two utilities. Total utility load was assumed to be 190,080 GWh in 2006, and to grow throughout the analysis period at 2 percent per year. The projections of utility rates, loads, and total revenue requirement are included in Appendix IV-A, as is a more detailed discussion of the development of the rate forecast.

Scenario Analysis

33 Percent Renewables Base Case Scenario. This scenario assumes that the RPS target is increased from 20 percent in 2010 to a 33 percent RPS by the year 2020. Most of the current RPS rules and procedures are assumed to remain in place, including the delivered energy requirements and prohibition of out-of-state RECs.[64] Seventy-five percent of RPS–related transmission costs are assigned to the RPS renewables, and there is no PTC or ITC available. This scenario assumes that the current target of a 20 percent RPS by 2010 is met. Contracts with renewable energy generators are assumed to be at the prices listed in Table IV-2. Because this analysis assumes that ratepayers pay the full costs of

---

[64] The analysis approach assumes that renewable energy included the 33 percent RPS will be awarded contracts based on bid prices, and these prices will on average be those listed in Table IV-2.

the RPS procurements, SEPS are not included in this analysis but are discussed qualitatively later in this Section. The impacts on utility revenue requirements of the 33 Percent Renewables Base Case are compared to a projection of utility revenue requirements under the current 20 percent RPS target. Average rate impacts are derived by dividing the incremental costs/benefits of moving to a 33 percent RPS by a projection of utility revenue requirements under the current 20 percent target.

Several sensitivity analyses are performed to bound the *33 Percent Renewables Base Case* results.

Natural Gas Market Price Forecast: Two cases are created that show the impact of varying the natural gas price forecast. Price forecasts are used that are 125 percent and 75 percent of the *33 Percent Renewables Base Case* forecast.

Renewables Costs: High and low renewable cost scenarios are evaluated. These cost scenarios are summarized in Section II *Summary of Existing Technical Information on Existing and potential Renewable Sources*.

PTC/ITC: The impact of continuation of the PTC and ITC through 2015 is assessed by adjusting the cost of renewables for the first five years of the analysis to reflect the effects of the PTC and ITC. These price impacts are also summarized in Section II *Summary of Existing Technical Information on Existing and Potential Renewable Sources*.

Transmission: Two cases are evaluated in which the portion of incremental transmission costs assigned to the costs of the incremental renewables purchased to move from a 20 percent to a 33 percent target is varied:

- 100 percent of incremental transmission costs are assigned to the incremental renewable purchases, and
- 25 percent of the incremental transmission costs are assigned to incremental renewable purchases.

In addition, there are several other policy choices and market developments that could impact the overall costs attributable to the RPS, including the allowance of out-of-state RECs, the amount of energy efficiency and distributed generation that comes on line, the elimination of SEPs, and natural gas price effects due to RPS implementation. These issues are discussed in more detail below.

Results

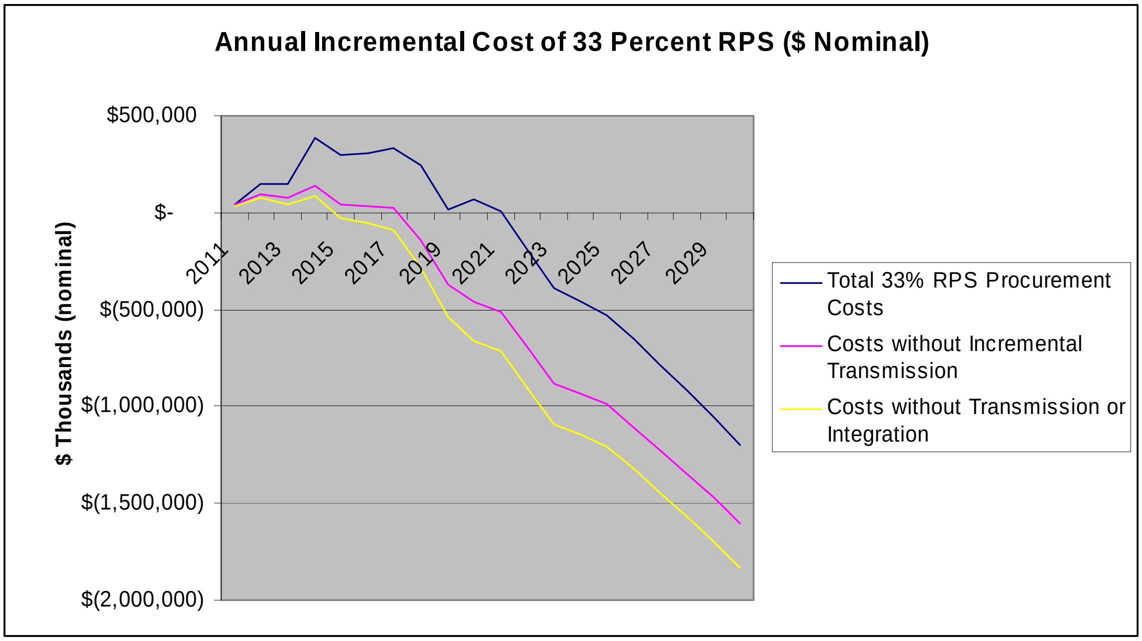
33 Percent Renewables Base Case: The *33 Percent Renewables Base Case* analysis results show that the RPS may result in small average rate increases through 2021, and beyond that will produce long term rate savings. On a net present value basis (2011$, 9% nominal discount rate), the RPS is found to increase costs to California IOU rate payers by $1.26 billion over the period 2011-2020, yielding an average 0.57 percent rate increase over the period. However, these cost increases are more than offset by ratepayer savings that accrue in the years 2021-2030, after the initial capital investments of the RPS have been completed. The net present value of RPS rate payer impacts for the period 2011-2030 is - $175 million (2011$, 9% discount rate), in other words a net savings. Table IV-3 below summarizes the average rate impact of the RPS for IOU customers during the 2011-2020 timeframe. Transmission and integration costs are significant drivers of the rate increases. Ignoring transmission and integration costs, the 33 percent RPS would result in rate decreases starting in 2015, with a 20 year NPV of -$3,874 million (9% nominal discount rate). These costs are illustrated in Figure 3-5 below.

Table IV-3. 33 Percent Renewables Base Case Average Rate Impacts

Year	Net Impact: Difference between Non-RPS IOU Rate Forecast and IOU Rate with RPS Procurement (10 year average 0.57percent)[65]
2011	0.16percent
2012	0.50percent
2013	0.47percent
2014	1.25percent
2015	0.88percent
2016	0.89percent
2017	0.92percent
2018	0.65percent
2019	0.03percent
2020	0.16percent

[65] The analysis predicted rates for only the 2011-2020 time frame, hence percent rate impacts are not presented for the 2011-2030 time frame. Throughout this section, the percentage net impact is the average difference between rates under a BAU scenario and rates under the 33 percent RPS case.

Figure IV-5: Annual Incremental Costs/Benefits of 33 Percent Renewables Base Case RPS Procurements



Sensitivity Analysis:

The results of the sensitivity analyses are presented in Table IV-4 below. Negative numbers indicate a net savings due to the RPS.

Table IV-4: Net Present Value and Rate Impact of RPS Scenarios (Negative number indicates rate reduction)

	10 year (2011-2020) NPV $million (2011$, 9percent discount rate)	**2011-2020 Average Rate Impact Attributable to 33 Percent RPS**	**20 year (2011-2030) NPV $million (2011$, 9percent discount rate)**
33 Percent Renewables Base Case	$1,264	0.57percent	-$175
Gas Price 125percent of *33 Percent Renewables Base Case*	-$672	-0.42percent	-$4,512
Gas Price 75percent of *33 Percent Renewables Base Case*	$3,200	1.77percent	$4,162

High Renewables Costs	$3,517	1.75percent	$4,188
Low Renewables Costs	-$230	-0.20percent	-$3,068
PTC/ITC Continue through 2015	-$445	-0.26percent	-$2,875
Transmission-100percent of incremental costs borne by RPS	$1,720	0.82percent	$702
Transmission – 25percent of incremental costs borne by RPS	$352	0.09percent	-$1,929

Gas Price Variations*:* As shown on the table above, variations in the forecast of natural gas prices can have significant impacts on the total cost impact of a 33 percent RPS. In this analysis, changes in natural gas prices impact utility rates through increased market prices for energy and increased fuel costs for utility owned gas fired generation. Increasing projected natural gas prices by 25 percent results in cost savings due to the RPS of $672 million over the first ten years of the study period, resulting in an average decrease in rates of 0.4 percent. This savings increases to over $4.5 billion on a net present value basis for the period 2011-2030. Reducing natural gas prices to 75 percent of the *33 Percent Renewables Base Case* projection results in an increase in the cost of the RPS. In the 2011-2020 time frame, these lower natural gas prices would result in an increase in the cost of the RPS by roughly $2 billion relative to the *33 Percent Renewables Base Case*, equivalent to an average rate impact of 1.8 percent. In the 2011-2030 time frame, the cost increase grows to approximately $4.3 billion relative to the *33 Percent Renewables Base Case.*

Renewables Cost Variations*:* Similar to variations in natural gas prices, variations in the cost of renewables can result in significant changes to the relative benefits of the RPS. The high renewables cost case results in a net present value impact of $3.5 billion and $4.2 billion over the 2011-2020 and 2011-2030 time frames, respectively. Lower renewable energy costs result in increases in RPS savings over the *33 Percent Renewables Base Case* of $230 million and $3.1 billion for the 2011-2020 and 2011-2030 time frames, respectively.

With and without PTC/ITC*:* The impact of the PTC and ITC is similar to the low renewables cost case. Continuation of these credits through 2015 has the effect of increasing the RPS benefit to $445 million and $2.9 billion in the 2011-2020 and 2011-2030 timeframes, respectively.

Incremental Transmission Costs*:* The impact of varying incremental transmission costs allocations to the RPS can also have significant impacts. Allocating 100 percent of these costs to the RPS results in roughly a $500 million increase in overall RPS costs in the 2011-2020 time frame. This impact is $877 million in cost increases in the 2011-2030 time frame. Reducing the portion of transmission costs allocated to the RPS creates cost savings. If only 25 percent of the costs are allocated to the RPS, the benefits to rate payers increase from the *33 Percent Renewables Base Case* by $1,754 million over the 2011-2030 time frame.

Other Impacts

<u>RECs and Avoided Transmission Costs</u>*:* Renewable Energy Certificates (RECs) may allow purchase of renewable attributes without having to provide physical delivery of renewable energy into California. The *33 Percent Renewables Base Case* scenario does not include out of state RECs as a compliance mechanism, and assumes that $3.8 billion (which produces a transmission revenue requirement of $7 billion for the period 2010-2030) will be invested in new transmission to facilitate delivery of in-state and near border renewable energy generation. If these transmission investments were not made or were delayed for some period of time, most new geothermal, approximately 5000 MW of wind and 1000MW of solar assumed to participate in the *33 Percent Renewables Base Case* scenario would no longer be available to deliver power to California utilities. This capacity would produce roughly 60 percent of the energy deliveries in the 2011-2020 timeframe necessary to meet a 33 percent RPS.

We do not recommend avoiding or delaying these critical transmission upgrades but because the State does not have full control over transmission upgrade decisions, it is worth considering the options should such a scenario present itself. Some portion of these renewables could potentially be replaced by RECs if the delivery requirement was lifted and unbundled REC purchases were allowed from out-of-state generation. The purpose of using RECs in this case is to allow the State's utilities to comply with their RPS mandate and to meet their greenhouse gas reduction goals while awaiting the completion of critical transmission upgrades. Also, allowing RECs may enable renewable generators to come on line at an earlier date, expanding the pool of eligible resources.

Another question is whether it would be beneficial from a rate perspective to cancel or defer some transmission upgrades designed to deliver renewables from outside the state into the state, or some upgrades that are at higher risk of non-approval in favor of replacing that power with RECs.

A case that exemplifies such a scenario is the delay of two investments: 500 kV Captain Jack-Olinda Tracy improvement and the final phase of the Tehachapi transmission expansion in 2020. Together, these investments total $1.6 billion. The impact of delaying these investments would be to reduce energy deliveries available to the RPS by a total of 7.7 million MWh. The delay of these investments would not result in energy shortages within the state, and RECs could offer a way for utilities to meet their RPS and greenhouse gas reduction obligations until the transmission was completed at a later time. The effect of not completing these transmission projects would reduce the 2011-2020

NPV costs of the RPS by $191 million, and the NPV costs for the 2011-2030 timeframe would be reduced by $757 million from the *33 Percent Renewables Base Case Scenario.*

If these investments were delayed, one option to consider would be the procurement of RECs and non-renewable energy to replace the 7.7 million MWh of renewable energy impacted by these transmission delays. Purchasing RECs and nonrenewable electricity to replace the renewable energy that would have been delivered to the RPS with these transmission investments is not likely to result in cost savings because the average cost of bundled renewable energy purchased for the RPS is projected to be lower than the nonrenewable market price during this time frame.[66] Nevertheless, RECs do provide a mechanism that would allow the IOUs to continue to comply with their RPS obligations if needed transmission upgrades were delayed.

One of benefits of bundled renewable energy purchases is their hedge value against rising natural gas prices. In a RECs procurement, this hedge value could be preserved through the use of contracts for differences tied to natural gas prices.

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

<u>High DG/PV Deployment</u>: Under any RPS case, DG deployment reduces the total amount of RPS procurement required in that it reduces the size of the load used to calculate RPS requirements.

Many experts project that photovoltaic (PV) costs will be considerably reduced over the period of time that is the subject of this analysis, substantially increasing the total amount of PV installed in the state. These PV installations would reduce RPS procurement requirements by reducing load, as would any other DG installation or energy efficiency investment. These installations could, if allowed, also provide RPS eligible resources. The cost impacts of PV on the RPS depend on a number of factors, including:

- The cost of PV in the 2010 to 2020 timeframe;
- The continued support of PV through public goods charges;
- Whether receipt of those funds requires the DG owner to relinquish all or a portion of their RECs, and how those RECs are then accounted for; and
- Prices in and availability of other markets for California PV RECs, including out of state RPS programs and the voluntary REC market.

<u>SEPs</u>: The *33 Percent Renewables Base Case* results show that in the 2011-2020 time period, the expected costs for RPS procurements will exceed market prices. Over market price renewable energy procurements account for $586 million, on a net present value basis (2011$), or roughly half of the incremental RPS costs in the 2011-2020 time frame.

[66] However, exceptions to this example could occur that could result in ratepayer savings such as a situation where RECs are combined with energy from a hydro plant, or where the transmission delays were earlier in the cycle when renewables are more expensive than the non-renewable energy market price.

The remaining rate impacts are due to transmission additions and integration costs. In the beginning of the 2011 to 2020 time period, with the exception of wind, all of the other renewables technology price estimates are above the market price forecast for non-renewables. However, by the end of that ten year period all of the technologies are cost competitive. As a result, under present SEP rules, some individual projects might be eligible for SEPs while others might not. However, it is not possible for us to identify which project types enter the supply mix in which years and therefore whether any would require SEPs. The bottom line is that over a twenty year period, the renewable portfolio would deliver rate payer savings without SEP payments.

<u>Natural Gas Price Effects:</u> Several Western states are in the process of implementing state RPS programs. The combined downward pressure that these RPS programs produce on the demand for natural gas for energy production may create a decrease in the price of natural gas, which has benefits for all California natural gas consumers.

> W*iser et al. (2005) reviews thirteen studies that have evaluated the impact that renewable energy and energy efficiency can have on natural gas prices. These studies show that, by reducing demand for natural gas, renewable energy deployment can put downward pressure on natural gas prices and consumer natural gas bills. …This effect is better considered in a regional setting where the impact of cumulative renewable energy investment on region-wide gas prices can be significant. For example, using the simplified analysis tool presented in Wiser et al. (2005), we find that new renewable additions currently called for in the WECC as a result of state RPS policies (in AZ, CA, CO, NM, and NV) and the utility resource plans included in our sample could, by 2014, reduce regional delivered natural gas prices by $0.06-$0.16/MMBtu (in 2003$), leading to consumer savings of between $7 and $18 per MWh of new renewable generation.*[67]

We used Berkeley Lab's simplified method to evaluate the *incremental* impact of a "33 percent by 2020" California RPS on natural gas prices in California (relative to the 20 percent by 2010 target).

Figure IV-6 presents the projected reduction in natural gas prices (average delivered price to all end-users in California) resulting from the *incremental* renewable generation spurred by a "33 percent by 2020" California RPS (i.e., relative to the current "20percent by 2010" California RPS). Price reductions are presented starting in 2011 for three different inverse elasticities: 0.8, 1.2, and 2.0. As shown, under a "33 percent by 2020" California RPS, delivered natural gas prices in 2020 could be between $0.05 and $0.13/MMBtu (in nominal dollars) lower than they would otherwise have been under the current "20 percent by 2010" California RPS, based on this simplified analysis.

[67] Mark Bolinger and Ryan Wiser, Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans, Lawrence Berkeley National Laboratory, LBNL-58450, August 2005, p. 55.

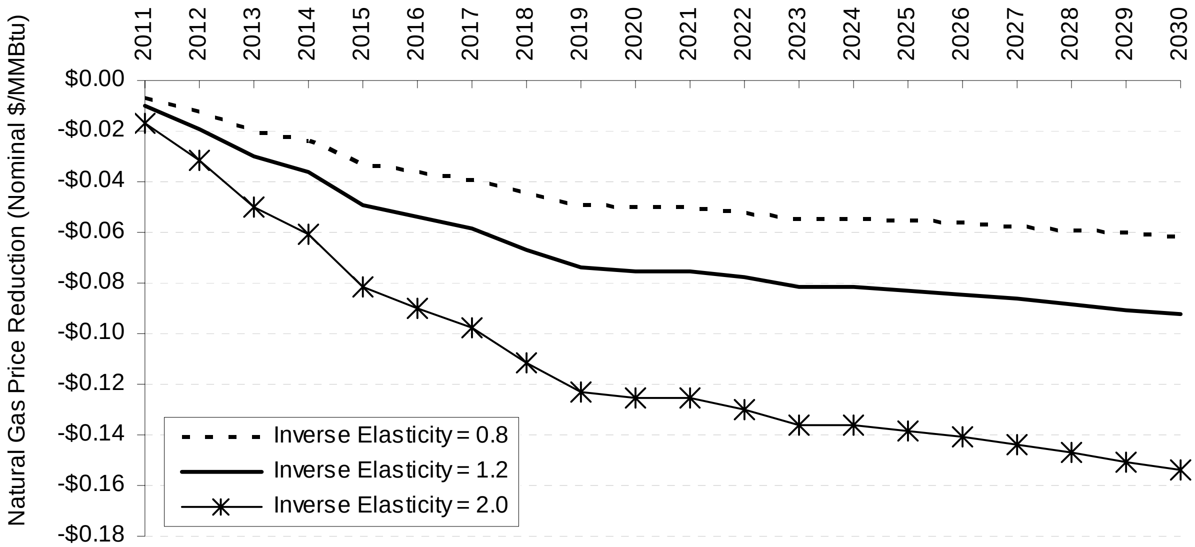


Figure IV-6. Incremental Delivered Natural Gas Price Reductions Under a "33 percent by 2020" California RPS

Figure IV-7 applies the delivered price reductions from Figure 3-6 to projected natural gas demand in California, to arrive at the projected net present value of consumer gas bill savings under a "33 percent by 2020" California RPS.[68] For an inverse elasticity of 2.0, Figure IV-7 shows that the net present value of gas bill savings from 2011-2020 (calculated in 2011) amounts to just over $1 billion, while the net present value of gas bill savings from 2021-2030 (again calculated in 2011) amounts to just under $1 billion. Over the entire period of interest, from 2011-2030, the net present value of gas bill savings in California consumers comes to roughly $2 billion.[69]

Finally, it is worth reiterating that the Berkeley Lab "simplified method" employed above is intended to provide only a first-order approximation of the likely gas price and bill impacts. Considerable uncertainty remains. Specifically, the national equilibrium models used to calibrate the simplified method have not done a particularly good job of forecasting natural gas price movements historically, and are also often not geared towards regional or state-level analysis. A review of other studies employing more-disaggregated regional modeling capabilities suggests that, if anything, Berkeley Lab's simplified method could be conservative, and that the price and bill impacts reflected in Figures IV-6 and IV-7 could be even larger than shown.[70]

---

[68] We used a 9% nominal discount rate to calculate net present value.

[69] Figure 3-7 also shows that at the lower end of the range, using an inverse elasticity of 0.8, the NPV of gas bill savings from 2011-2030 comes to roughly $0.8 billion.

[70] For example, see American Council for an Energy-Efficient Economy (ACEEE). 2003. *Natural Gas Price Effects of Energy Efficiency and Renewable Energy Practices and Policies*. Report Number E032. Washington, D.C.: American Council for an Energy-Efficient Economy. (Authors: R. Elliot, A. Shipley, S. Nadel, and E. Brown). http://aceee.org/pubs/e032full.pdf

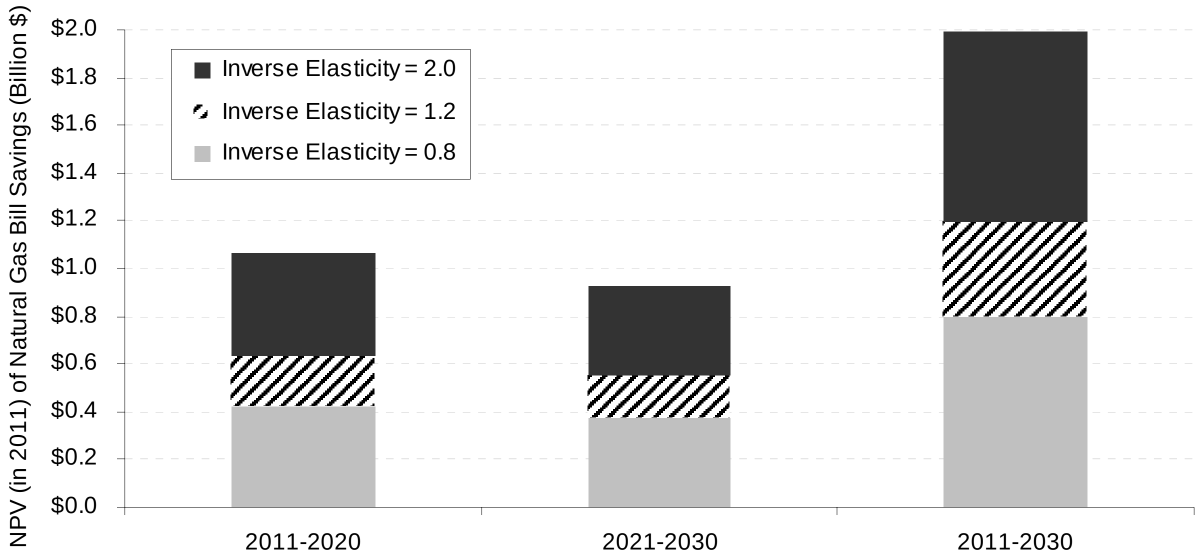


Figure IV-7. Consumer Natural Gas Bill Savings Under a "33 percent by 2020" California RPS

"But for the purchase of these resources" is always a thorny issue to deal with because of the tendency of some critics to see the lower natural gas prices and think the state should not have invested in renewables because natural gas is now less expensive. This discussion is included only as a caveat for future regulators to remind them that the effect is *because* of the renewable purchases and should be added into the "renewables benefits column" not deducted as a cost.

Energy Efficiency: The amount of renewable energy required to meet the 33 percent RPS will be reduced by the amount of energy efficiency savings developed during this period. Thus the actual cost of the 33 percent RPS will also be reduced when energy efficiency programs for that period are incorporated. This analysis does not include a quantitative evaluation of expanded energy efficiency demand reductions. Energy efficiency is assumed to be a contributor to the overall load growth rate in the state. For this analysis, we assumed load would continue to grow at this historical rate of 2 percent per year.

Conclusions and Recommendations

Achieving a 33percent RPS is shown to be possible with relatively small ratepayer impacts in the first decade of 2011-2020 (0.57 percent average overall rate increase) and longer term ratepayer benefits (NPV of $175 million in savings) in the 2011-2030 timeframe. The sensitivity analysis demonstrates that varying analysis assumptions, such has the level of future natural gas prices, the cost of renewables, and the burden of new transmission on the RPS can have meaningful impacts on the overall costs of the RPS. However, the overall rate impacts of the variables addressed in the sensitivity analysis remain relatively small. Nevertheless, as this analysis demonstrates, there is considerable uncertainty surrounding future projections of RPS costs and benefits. Given this uncertainty, it is important to adopt policy mechanisms that give California flexibility to adapt to different future market scenarios. Such policy mechanisms may include:

- RECs. Unbundled RECs have several benefits that add flexibility to policy implementation and may decrease costs. While allowance for shaped products and out-of-territory delivery may achieve many of these benefits, allowing unbundled RECs may provide even greater flexibility in transmission expansion implementation. Allowing unbundled RECs to participate in RPS procurements may also put competitive downward pressure on bundled renewable energy costs.

- Contracting mechanisms. Uncertainty about future costs can be dealt with through various contracting mechanisms. For example, mechanisms such as contracts for differences can provide a cap on the so-called "above market" costs associated with RPS procurements. Such mechanisms may be especially useful if unbundled RECs are allowed.

Period of Benefits: This analysis demonstrates that although the RPS is likely to create small increases in rates during the 10 year period of policy implementation, there are significant ratepayer benefits created by the RPS after the RPS targets are reached during the useful life of these renewable projects. **Any future analyses of RPS impacts should be structured to recognize those impacts by incorporating a long term time horizon in any cost or economic analyses.**

Market Prices: Throughout this analysis, there is the general assumption that market prices will continue to increase over time. The expectation of long term market price increases has implications for contract terms. **Long-term renewable energy contracts will likely yield the most positive benefits for California rate payers.**

As this analysis demonstrates, the average price of the renewables purchased under a 33 percent RPS case will fall below the market price of new natural gas generation. **To capture these benefits, RPS procurements must be able to request bids from renewable generators that are based on the costs of production and not an anticipation of the costs of new natural gas fired generation.**

Transmission Investments: It is possible to meet the 33 percent target without making major transmission investments, but it would likely require broad allowance for out-of-state renewable energy and RECs, in which case the state would lose some of the economic development benefits of the development of significant amounts of new renewables in the state. The impact of transmission expansion in the *33 Percent Renewables Base Case* is significant. **To manage these costs, policies that allow longer term phasing of transmission investments, and, as discussed above, the use of RECs as a transitional mechanism, should be considered.**

SEPs*:* As shown in the *33 Percent Renewables Base Case analysis*, the overall projected rate impact of a 33 percent RPS is relatively small, averaging 0.57 percent over the 2011-2020 time frame. Even in the high renewable energy cost case, the overall rate impact is under 2 percent. In the *33 Percent Renewables Base Case*, one-half of this increase is attributable to the over market costs of renewables procurement- the remainder attributable to transmission and integration costs. This small rate impact shows that eliminating SEPs would have a limited impact on actual utility rates though SEP elimination could significantly simplify RPS program administration. This bolsters recommendations in Section II to eliminate the SEP program.

APPENDIX IV-A

Utility Rate and Load Forecast

The table below lists the rate forecasts developed for this analysis. For the rate impact analysis in this report, we assumed that the average rate for the three IOUs is equal to the average of the SCE and PG&E rate forecast during the period 2011-2020. Total rate impacts for the period 2011-2020 were calculated as a percentage:

$$\frac{\text{Net Cost of RPS Procurements 2011-2020}}{\text{Total Utility Revenue 2011-2020}}$$

Table IV-A-I: Forecast of Business as Usual (BAU) Rates and Utility Revenues

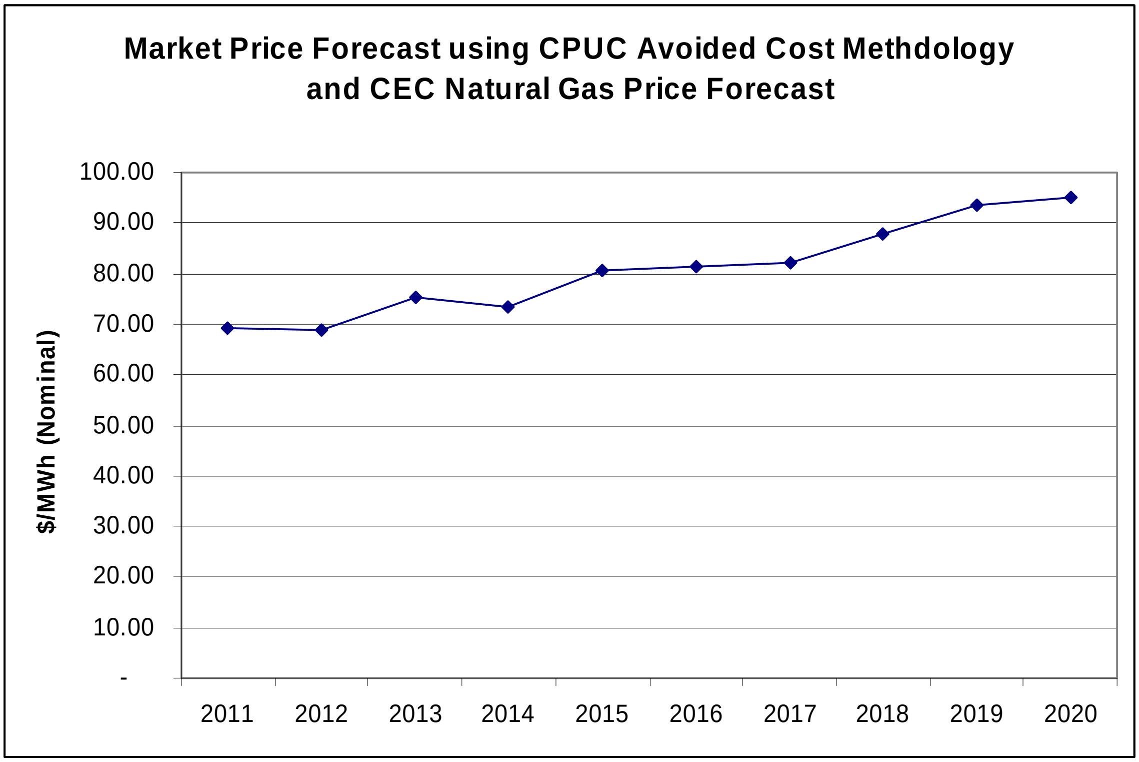
	Edison Average Rate $/kWh	PG&E average Rate $/kWh	IOU Average $/kWh	PG&E, Edison, and SDG&E Sales kWh (190,080 GWh in 2006, 2% annual increase)	Total Revenue
2006	0.1267	0.1237	0.1252	190,080,000,000	$23,796,621,042
2007	0.1258	0.1237	0.1248	193,881,600,000	$24,190,881,617
2008	0.1194	0.1150	0.1172	197,759,232,000	$23,175,582,751
2009	0.1295	0.1306	0.1300	201,714,416,640	$26,231,783,863
2010	0.1277	0.1204	0.1240	205,748,704,973	$25,521,310,773
2011	0.1370	0.1308	0.1339	209,863,679,072	$28,102,445,777
2012	0.1367	0.1310	0.1339	214,060,952,654	$28,654,179,354
2013	0.1441	0.1382	0.1412	218,342,171,707	$30,822,371,558
2014	0.1440	0.1345	0.1393	222,709,015,141	$31,014,086,045
2015	0.1527	0.1421	0.1474	227,163,195,444	$33,485,212,454
2016	0.1551	0.1443	0.1497	231,706,459,353	$34,689,465,776
2017	0.1587	0.1466	0.1527	236,340,588,540	$36,079,024,928
2018	0.1645	0.1535	0.1590	241,067,400,310	$38,327,069,437
2019	0.1777	0.1612	0.1694	245,888,748,317	$41,662,974,228
2020	0.1798	0.1637	0.1718	250,806,523,283	$43,079,001,668

MARKET PRICE FORECAST

Market prices were developed using the methodology developed for the CPUC avoided cost proceeding in April 2005. This proceeding adopted a methodology similar to the MPR methodology in that future market prices are calculated based on the costs of a new combined cycle combustion turbine. The worksheet used to develop these prices can be found at: http://ethree.com/cpuc_avoidedcosts.html. For this study, the only data that were updated from the CPUC electricity avoided cost calculation were the natural gas price forecasts. The CPUC electricity avoided cost calculation uses an average of three natural gas price forecasts to develop a natural gas price forecast for the post 2010 period.

In this analysis, we replaced this average natural gas price forecast with the natural gas price forecast developed by the CEC (see above). The chart below summarizes the baseload market price forecast used in this analysis.

Figure IV-A-1: Baseload Market Price Forecast using CPUC Avoided Cost Methodology and CEC Natural Gas Price Forecast



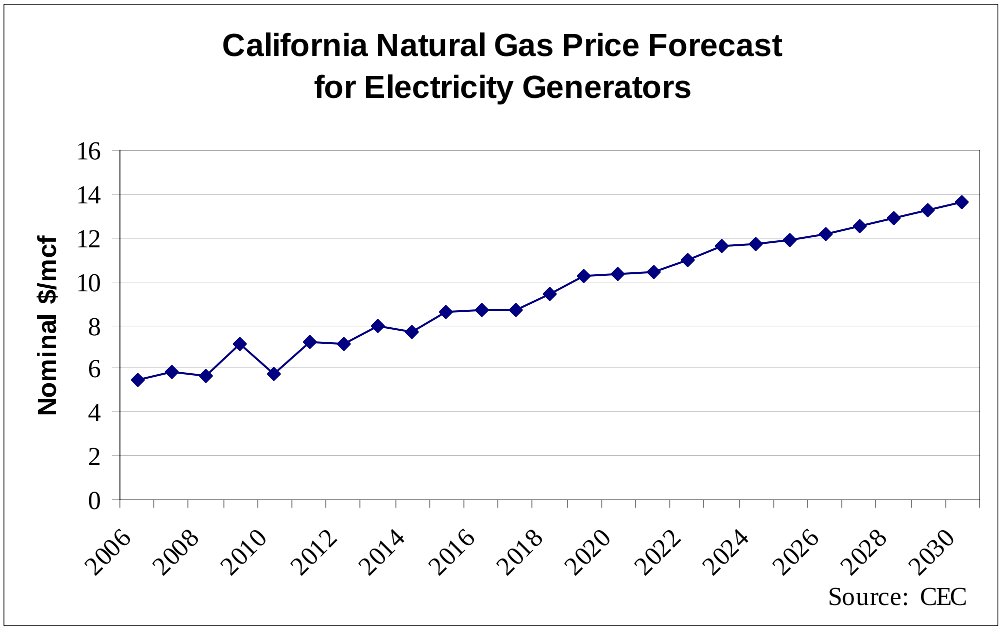
The market value of renewable energy under the RPS was based on this market price forecast, and adjusted by time of delivery factors.

NATURAL GAS PRICES

The natural gas price forecast was developed by the California Energy Commission as part of the 2005 IEPR.[71] These prices are weighted average annual prices for the power generation sector in California. The CEC forecasting model produces prices through 2025. Prices for the period 2026-2030 were derived by applying an annual escalation factor based on the average escalation factor of the prior five year period.

[71] Revised Reference Case in Support of the 2005 Natural Gas Market Assessment - Revised Staff Report. Posted: September 27, 2005, CEC publication # CEC-600-2005-026-REV. This document presents a natural gas forecast for the period 2006-2015. The CEC staff forecast for the 2016-2025 period was provided to the authors by CEC staff, but was not officially adopted as part of the 2005 IEPR report.

Figure IV-A-2: Forecast of California Natural Gas Prices for Electricity Generators



TIME OF DELIVERY FACTORS AND RENEWABLE ELECTRICITY MARKET VALUES

This analysis relied on the TOD definitions for SDG&E in the CPUC avoided cost spreadsheets. SDG&E's TOD period definitions were used because they were the most granular of the TOD definitions included in the worksheet. Those definitions are listed below.

Table IV-A-2: TOD Definitions

TOU Period	Definition
1	11am-6pm M-F May-Sep
2	6am-11am, 6pm-10pm M-F May-Sep
3	10pm-6am, MF, all day Sa Su May-Sep
4	5pm-8pm M-F, Oct-Apr
5	6am-5pm, 8pm-10pm M-F Oct-Apr.
6	10pm-6am, MF, all day Sa Su Oct-Apr

The CPUC worksheet was used to develop TOD factors for each TOD period. These TOD factors were applied to the baseload market price forecast produced by the CPUC methodology to develop TOD market prices. For each of the renewable resources included in the RPS, we estimate the number of hours of technology's output that would fall into each TOD period, and then applied the TOD factors to develop an average market value for each resource type. These market values ($/MWh) are listed below.

Table IV-A-3: Market Value of Renewable Energy ($/MWh)

Year	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Baseload	69.18	68.68	75.31	73.25	80.53	81.33	82.13	87.82	93.67	94.90
Wind	67.78	67.29	73.78	71.76	78.90	79.68	80.46	86.03	91.77	92.97
Geothermal	67.59	67.10	73.58	71.56	78.68	79.46	80.24	85.79	91.52	92.72
Biomass	67.55	67.07	73.54	71.52	78.64	79.41	80.20	85.75	91.47	92.66
Conc. Solar	79.64	79.06	86.69	84.32	92.70	93.62	94.55	101.09	107.83	109.24

Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Baseload	96.16	100.67	105.32	106.69	108.08	110.94	113.87	116.87	119.96	123.13
Wind	94.20	98.63	103.18	104.53	105.89	108.68	111.55	114.50	117.52	120.63
Geothermal	93.94	98.35	102.90	104.24	105.60	108.38	111.25	114.18	117.20	120.30
Biomass	93.89	98.30	102.84	104.18	105.54	108.32	111.18	114.12	117.14	120.23
Conc. Solar	110.69	115.89	121.24	122.82	124.42	127.71	131.08	134.54	138.09	141.74

REVENUE REQUIREMENT FOR TRANSMISSION ADDITIONS

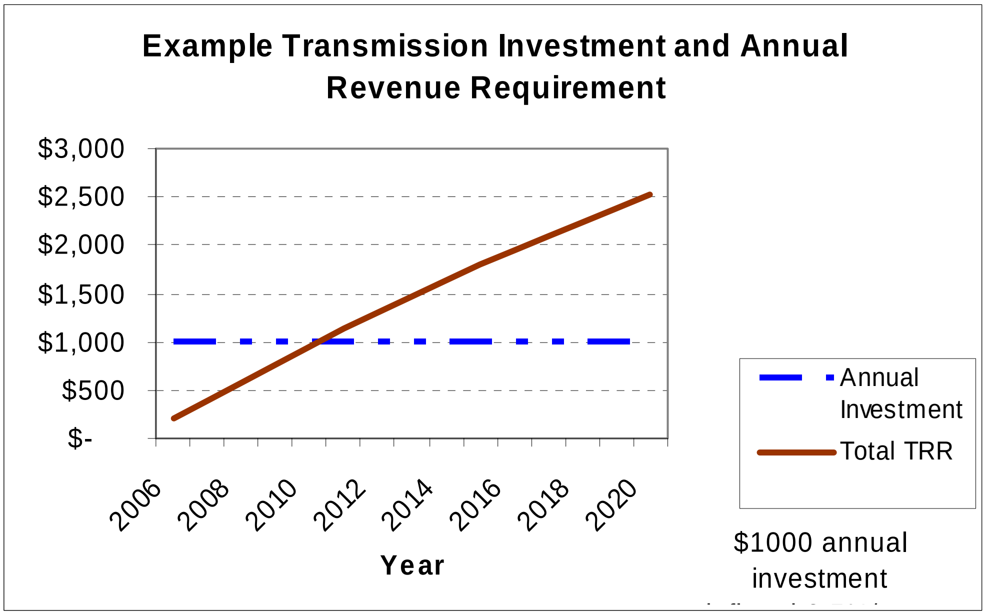
Transmission rates: The transmission component of rates was forecast using a simple transmission revenue requirement calculation. Basic assumptions are listed in the table below.

Table IV-A-4: Transmission Revenue Requirement Assumptions

TRANSMISSION REVENUE REQUIREMENT ASSUMPTIONS		
Inflation Rate	2.5%	
Net Salvage	-50.0%	
Book Life (Years)	45.00	
Discount Rate	8.70%	
Return	8.70%	
Debt	5.94%	45.5%
Common	11.22%	52.0%
Preferred	6.42%	2.5%
Federal Income Tax	35.0%	
State Income Tax	8.8%	
Property Tax	1.1%	

The chart below illustrates the transmission revenue requirements that result from a $1000 annual investment in transmission.

Figure IV-A-3: Forecast of Transmission Revenue Requirement for $1000 Annual Investment



RPS PROCUREMENT SCHEDULE

The table below lists the annual incremental RPS procurement by technology used in this analysis.

Table IV-A-5: Total Annual Incremental Production by Technology for PG&E, SCE and SDG&E (Gigawatt hours)

Year	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Wind	1776	1838	1903	1969	2038	2108	2180	2255	2331	2410
Geothermal	1065	1103	1142	1182	1223	1265	1308	1353	1399	1446
Biomass	355	368	381	394	408	422	436	451	466	482
Solar	355	368	381	394	408	422	436	451	466	482
Total	3551	3677	3806	3939	4076	4216	4361	4509	4662	4819

INTEGRATION COSTS

The approach to estimating integration costs is described in *Summary of Existing Technical Information on Existing and Potential Renewable Sources.* Two cost factors were added to wind energy costs to reflect the integration costs. The first is an energy cost adder. This adder was assumed to be $2/MWh in 2011, increasing linearly to $5/MWh by 2020. After 2020, this adder was escalated at the same rate as the market price forecast.

The second adder is a capacity cost based adder, which also includes an energy credit to reflect the energy value associated with the capacity cost. The calculation of this adder and benefit is illustrated below.

Table IV-A-6: Integration Capacity Adder Example

Wind Nameplate incremental MW	579
Wind capacity credit	20%
Wind capacity factor	35%
MW Difference between credit and CF	87
Cost per kW	$95
Total Capacity Cost	$8,260,837
Gross Cost per incremental MWh (total cost / incremental wind procurement in year)	**$4.65**
Energy benefits per kW	30.00
Energy offset (total costs)	$(2,606,083)
Energy benefit per MWh	**($1.46771)**

NATURAL GA S PRICE EFFECTS

The assumptions that went into the calculation of RPS impacts on natural gas prices include:

- a projection of nationwide natural gas demand from the Energy Information Administration's Annual Energy Outlook 2005;
- a projection of California natural gas demand, as well as natural gas prices delivered to California electricity generators, from the California Energy Commission's 2005 IEPR report and CEC staff;
- the projection of the *incremental* renewable generation from a "33% by 2020" California RPS (i.e., above and beyond a "20% by 2010" California RPS) used in this report's cost analysis;
- an assumption that each MWh of new renewable generation will displace 0.75 MWh of gas-fired generation, with a heat rate of 7,500 Btu/kWh;
- an assumption (substantiated by the Berkeley Lab report) that changes in national average wellhead gas prices will flow through on a one-for-one basis to national average delivered gas prices; and
- an assumption (again substantiated by the Berkeley Lab report) that changes in California delivered prices will initially be amplified relative to changes in national delivered prices, but will eventually decline to parity over time.[72]

[72] Specifically, we assumed that changes in California delivered prices relative to changes in national average delivered prices will start at 3:1 in 2006, and then decline linearly until reaching 1:1 in 2020 and thereafter. This state or regional "multiplier" reflects the impacts of natural gas transportation constraints into California: initial RPS-induced reductions in natural gas demand are likely to have an amplified effect in California (relative to the nation as a whole) to the extent that such reductions ease transportation constraints that inflate delivered prices relative to wellhead prices. Over time, we assume that any such transportation constraints will be alleviated, either through new pipeline capacity or ongoing demand reduction, thereby bringing California gas price changes more in line with the national average.

V. PROCESS AND POLICY CHANGES NECESSARY TO MEET A 33 PERCENT RENEWABLES TARGET

In this section we provide *preliminary* recommendations for policy and process changes that may be necessary for the state to *make progress* towards the 33-percent-by-2020 goal (see Table V-1 for a tabular summary). Policy recommendations addressing transmission needs, the Transmission Ranking Cost Report (TRCR), operational integration challenges, distributed generation, and voluntary renewable energy markets are covered in later sections of this document.

The recommendations presented in this section are informed by stakeholder views of the present RPS design as revealed by a recent CEC report (which focused on the 20 percent-by-2010 goal), CEC IEPR documents and filings, and the Energy Action Plan II. Importantly, these recommendations were also vetted with and reviewed by the CPUC. Ultimately, however, the recommendations are our own, and would benefit from more thorough analysis and stakeholder input, as well as further input from the CPUC. We are under no illusion that every party will agree with each and every recommendation that follows, but hope that as a whole these recommendations offer useful insights to the state as it seeks to achieve a 33 percent renewable energy goal.

To be clear, our focus is not on identifying near-term actions that are necessary to achieve a 20 percent renewable energy target, but instead on highlighting actions that may be critical to achieving the 33 percent goal. Nonetheless, in part based on conversations with CPUC staff and as shown in Table 3, we believe that at least some of these recommendations are likely to be addressed in order to meet the 20 percent goal.

We also recognize that many of the recommendations summarized in Table 3 and discussed in the text that follows would require legislative change. New legislation is necessary if the state is to be sure of achieving a 33 percent goal; existing CPUC jurisdiction may allow the state to exceed a 20% target, but cannot assure achievement of 33 percent goal. We therefore identify those recommendations that would likely require legislative action, as distinguished from those that appear possible under current law.

Finally, we note that a subset of these recommendations is analyzed later in this report from a cost-benefit perspective.

Table V-1. Preliminary Policy Actions for Achieving a More Aggressive RPS

Recommended Actions		Assumed to Be Implemented for 20 % Target*	Necessary for 33 % Target	New Legislation Needed
Firmly Establish the 33 % Target in Legislation				
	Codify 33 % target for the state's IOUs, ESPs, and POUs		✔	✔
	Incorporate legislative or regulatory flexibility to alter 33 % target		✔	✔

Better integrate renewables into general procurement planning	✔	✔	
Regulatory Process Changes			
Augment staffing and provide consistent focus on RPS	✔	✔	
Continuously prioritize items most critical to target achievement	✔	✔	
Increase transparency of certain information		Consider	**?**
Develop an RPS that Works for ESPs and CCAs			
Provide procurement flexibility to ESPs/CCAs	✔	✔	**?**
Develop central procurement agent for ESPs/CCAs		Consider	**?**
Speed and Streamline the Solicitation Cycle			
Streamline the current regulatory requirements and processes	✔	✔	
Allow less frequent but larger formal RPS solicitations, with greater allowance for bilateral contracts		Consider	
Establish RFO-cycle deadlines for IOUs		Consider	
Further standardize contracts, and RFO requirements	✔	Consider	
Other measures (see text)		Consider	**?**
Address Contract Failure			
Encourage over-contracting by clarifying the application of penalties and flexibility mechanisms	✔	✔	
Evaluate how bid deposits, credit requirements, and bid evaluation protocols can minimize the risk of contract failure	✔	✔	
Require over-contracting for renewable energy		Consider	
Provide Delivery Flexibility, and Allow Unbundled RECs			
Allow shaped products if energy delivered to state	✔	✔	
Allow generator delivery to out-of-state hubs, with purchaser delivery into state		✔	**?**
Standardize evaluation of projects with out-of-territory delivery		Consider	
Allow in-state unbundled RECs, possibly with restrictions		Consider	**?**
Allow out-of-state unbundled RECs, possibly with restrictions		Consider	✔
Consider applying SEPs to RECs		Consider	✔
Develop Appropriate Mix of Carrots and Sticks			
Regulatory vigilance and application of current penalties	✔	✔	
Clarify or revise system of penalties and flexibility mechanisms		Consider	
Additional procurement flexibility if new transmission expected for major renewable additions		Consider	**?**
Utility profit incentives for renewables procurement		Consider	
Eliminate MPR-SEP Structure		Consider	✔

* Many other items might also be useful to address in the achievement of the 20 % goal; here we identify only those that we believe are very likely to be addressed by the CPUC under current statutory authority.

Firmly Establish the 33 % Target in Legislation

New legislation codifying the 33 percent renewable energy target is necessary if the state is to be assured of achieving this aggressive goal. SB 1078 disallows the CPUC from establishing renewable energy *requirements* that exceed 20 percent, and we believe that it is unrealistic to think that the CPUC could *encourage* (through incentive mechanisms, resource planning requirements, or otherwise) electricity providers under their jurisdiction to achieve an exact 33 percent renewable energy share. New legislation would also be required to address many of the other recommendations discussed in the sub-sections that follow. Moreover, new legislation is crucial if the more aggressive target is to apply on a *statewide* basis, covering not only CPUC-jurisdictional IOUs, ESPs, and CCAs, but also the state's publicly owned utilities. Though some additional flexibility might be warranted for the state's smallest electric utilities, achieving a *statewide* renewable energy target will require *statewide* application of the purchase requirement. A broader application of the policy to all of the state's electricity providers may also ease concerns about unequal cost burdens.[72]

We understand that to achieve a 33 percent target, the 20 percent requirement must first be obtained. We also recognize that opening a legislative discussion over the 33 percent goal may create some uncertainty for and disrupt achievement of even the 20% requirement unless this is handled skillfully.[72] Legislative discussions over a 33 percent target should therefore be approached with care. Nonetheless, there are a number of reasons to believe that early establishment of such a requirement would be desirable. Most importantly, achieving a 33 percent renewable energy share will likely require considerable transmission investments, which will take time from conception to operation. A 33 percent renewable energy share may also require different strategies for integrating intermittent or "must-take" energy into the state's electrical grid, and a longer planning horizon would facilitate the development of those strategies. Finally, for those electricity suppliers that are already near the 20 percent target, the development of a 33 percent goal would provide an incentive for continued aggressive renewable energy purchases in the near to medium term.

A 33 percent renewable energy goal is clearly aggressive, and the costs and benefits of achieving such a target cannot be known with certainty. We therefore recommend that the state's policymakers retain a degree of flexibility to alter the renewable energy purchase targets as necessary. One simple approach would be to require the CPUC (perhaps in concert with the CEC) to submit an RPS "progress report" to the legislature every two years. Those reports could document progress towards the 33 percent goal, and identify recommended legislative actions, including any reduction in future target levels deemed necessary at that time.

Even without new legislation codifying a 33 percent target, the CPUC may be able to encourage suppliers to go beyond the present 20 percent requirement by strongly implementing the state's loading order preferences through the IOUs' general procurement activities. With natural gas prices reaching new highs, and with a re-invigorated concern about global climate change, attractive opportunities for renewable energy may be overlooked if they are not carefully evaluated within a holistic, integrated resource planning and procurement framework. Such a framework can be defined by least-cost, best-fit analysis, but such analysis needs to consider a broader array of social objectives than those currently incorporated in utility analysis procedures.[72] At a minimum, such a framework must be able to balance the expected cost and risk of different resource options, fairly compare fixed-price renewable to variable-price fossil resources, and address the risk of future regulatory changes, including climate regulations. We understand that the CPUC plans to tackle these issues in the months ahead, and will look to better integrate loading order preferences in general procurement activities. These efforts are commendable, and we recommend them without reservation.

Regulatory Process Changes

Successfully implementing a 33 percent RPS will require aggressive, consistent, and coordinated action not only from the CPUC, but also from the CEC and the California ISO. The scope of this task cannot be over-estimated, and the CPUC is already seeking to address some of these concerns within the context of the present RPS.

The regulatory obligations imposed on the CPUC and the CEC are substantial, and should be matched with a sizable, professional staff dedicated to renewable energy issues within each of these three state agencies. Moreover, given these regulatory demands, it is essential for the state's energy agencies to continuously prioritize the regulatory issues that are most critical to the achievement of the state's renewable energy goals. Less significant issues can and should be left for future decisions.

We understand and appreciate that the CPUC has statutory requirements to keep sensitive data and information confidential, and that the CPUC has opened an investigation on this issue (R.05-04-040).[72] We are also mindful that the release of certain information may weaken the bargaining position of a utility renewable energy buyer and that legislative change may be necessary to achieve transparency in some areas. Nonetheless, we believe that increased transparency of at least certain information is important to the future success of the state's RPS. For example, without at least aggregated information on generator response to renewable energy solicitations (quantity and price), the state's policymakers will be unable to provide an effective ongoing public assessment of whether the 33 percent goal is achievable, at what expected cost, and whether legislative change is warranted.

Develop an RPS that Works for the State's ESPs AND CCAs

ESPs presently serve approximately 13 percent of load in California; whether this percentage grows or shrinks in future years will depend on future regulatory and legislative decisions. Regardless of the fate of ESPs and CCAs, ESP and CCA RPS compliance will pose special challenges for the CPUC. The loads served by ESPs are often relatively small, and ESPs and CCAs will not all be in a position to commit to long-term renewable electricity contracts. Even if such contracts are provided, a long-term contract with an ESP that has poor credit will do little to meet the needs of renewable energy project financiers. The overall RPS design in California (as defined by statute and subsequent regulations), with renewable energy procurement plans, advance approval of bid solicitations, PRG review of contracts, and CPUC contract approval, may simply not make sense for ESPs and CCAs, and if applied to ESPs and CCAs, would impose substantial regulatory burdens on the CPUC.[72] Meanwhile, SB 1078 offers unclear guidance on the level of discretion the CPUC has to account for these differences when applying the RPS to ESPs and CCAs. Finally, we expect that many of the state's ESPs and CCAs will be starting with a smaller percentage of their supply coming from eligible renewable sources than did SCE and PG&E, making both the 20 percent and the 33 percent renewable energy targets more difficult to achieve.

The CPUC is presently working to develop an overall compliance framework for the state's ESPs and CCAs (with a scoping decision currently expected by mid-November), and we assume that (despite the complexity) these issues will be largely resolved prior to achieving the 20 percent RPS. Specifically, we assume that some degree of procurement flexibility will be offered to the state's ESPs and CCAs, which could include some or all of the following: (1) allowing unbundled RECs, (2) allowing shorter-term contracts, and/or (3) waiving the detailed procurement process requirements imposed on the state's IOUs. We understand that each of these "variances" has advantages and drawbacks, and that hard tradeoffs may be required. As a result, each of these measures may need to be conditioned on certain other requirements for example, the CPUC could allow procurement flexibility but not allow SEPs to apply to any renewable energy contracts that result. We also recognize that renewable energy generators often need long-term power purchase agreements though an increasing amount of "merchant" development is now occurring in other states such as Texas, arguably one of the more successful RPS policies in the nation. Reconciling the needs of ESPs and CCAs and renewable energy generators will clearly be a challenge, and some of the measures discussed above may require (or at least benefit from) legislative change.

There have also been discussions about the possibility of a "central procurement agent" that could purchase renewable energy on behalf of ESPs/CCAs or their customers, and that would otherwise follow similar procurement processes as the state's IOUs. A key advantage to such an approach is that it would allow renewable energy generators to secure long-term contracts with credit-worthy players. The creation of central procurement agents, however, may require a significant level of regulatory oversight from the CPUC. Some central procurement designs would not require legislative changes,[72] while others may require such changes. Though we expect and encourage central procurement ideas to be vetted in advance of the 20 percent requirement, given the potential advantages, we also recommend that they continue to be considered in the context of a 33 percent target.

Though issues associated with ESPs and CCAs are often conflated, significant differences may exist between these market players. In particular, CCAs are just now being discussed and formed by local governments. The jurisdictions most interested in developing CCAs are driven in part by environmental goals and a desire to go beyond the 20 or 33 percent state renewable energy mandates. There is discussion among CCAs of self-financing renewable energy projects with revenue bonds in order to potentially reduce costs. Some have posited that they could reach a 50 percent renewable goal for the same cost as reaching a 33 percent target. As a result, though there may not be a large number of communities in the state that actually undertake formation of a CCA, those that do so appear predisposed to incorporate a higher proportion of renewables than either the IOUs or ESPs.

Speed and Streamline the Solicitation Cycle

Achieving a 33 percent renewable energy target will require frequent and sizable renewable energy solicitations. Even to achieve the 20 percent RPS, some streamlining of the solicitation cycle is necessary. We understand that the CPUC plans to tighten the solicitation cycle in future years by, for example, simplifying, speeding, and consolidating regulatory processes, filings, and decisions, and by incorporating long-term renewable energy procurement plans within the general procurement plans of the IOUs.[72] We further assume that the state's electricity suppliers will learn to more rapidly proceed with their solicitations in order to achieve the 20 percent goal, building off of experiences gained in the first set of RFOs. In fact, we understand that the CPUC will ask utilities to consider "lessons learned" from previous RPS solicitations in late 2005 as part of regulatory filings for short-term procurement.

We are hopeful that the above actions will be all that is needed to speed and streamline the solicitation cycle. If these changes prove insufficient, however, the CPUC may want to consider less frequent but larger RFOs (e.g., a 1½ or 2 year RFO cycle), combined with a more lenient stance towards bilaterally negotiated deals in order to keep pace with the RPS requirements (only for power purchases; utility ownership should continue to be pursued only through competitive solicitations).[72] We recognize, though, that less frequent and larger RFOs have risks of their own, and if they fail, the chances of not meeting RPS targets increase. Alternatively, the CPUC might consider establishing deadlines by which utilities must submit contracts under each RFO, or further standardizing procurement practices and contract terms and conditions to minimize the time consuming process of negotiating with short-listed bidders.[72]

In the event that even these approaches do not yield timely procurements (under either the 20 percent or 33 percent targets), the state may wish to take more extreme measures. Such measures include the development of fixed-price standard offer contracts available on a first-come, first-served basis for eligible renewable generators, or the development of a statewide "central procurement" agent that would make purchases on behalf of the state's load serving entities. At least some elements of these strategies would require legislative change.

Address Contract Failure

An emerging concern in California and other states is that of contract failure: the nearly inevitable situation in which signed contracts with renewable projects do not *all* yield operating facilities on the schedule originally envisioned. We strongly encourage the CPUC to anticipate and address this risk now, instead of addressing it after the fact by either imposing burdensome noncompliance penalties on utilities or essentially granting the utilities a "free-ride" and forgiving their lack of compliance. Addressing the issue in the near term will ensure that the state's utilities do not fall behind in achieving their renewable energy purchase requirements, an especially important goal if the procurement target is raised to 33 percent.

The CPUC took an important initial step in this direction recently in D.05-10-014 by acknowledging the risk of contract failure and requiring utilities to quantify the "margin of safety" for over-contracting that should be applied to achieve both annual procurement targets and for the 2010 target.[72] We also understand that the CPUC will require utilities to consider "lessons learned" from their recent RPS solicitations in their short-term procurement filings that are due by the end of 2005.

In the near term, we expect and recommend further CPUC action in this area through additional clarification of the application of penalties and flexibility mechanisms in the event of contract failure. Such clarification should recognize that even with good faith, best efforts neither the generator nor the utility purchaser will be able to foresee all sources of contract failure. Nor should such clarification unduly discourage utilities from contracting with some more speculative projects, especially if those projects hold the promise of providing substantial ratepayer value.

Given these considerations, we recommend that the CPUC provide up-front guidance on the *specific* conditions that would have to be met for penalties to be waived in the event of contract failure. In particular, the CPUC might consider waiving annual penalties only if a utility clearly demonstrates that it has reasonably over-contracted for renewable energy by (for example) a 20 percent margin, but has still fallen short of its procurement obligations due to a greater-than-expected level of contract failure.[72] A non-compliant utility that fails to meet its purchase obligation because it chose not to over-contract should not be provided such a waiver. We further expect and recommend that the CPUC will continue to evaluate how bid deposits, credit requirements, and bid evaluation protocols might be used to minimize the risk of contract failure, while at the same time not overly limiting the number of project bidders.

Finally, the CPUC should consider *requiring* utilities to "over-procure" renewable energy by a specific margin, in anticipation of some level of contract failure. The required margin of over-contracting could be changed over time as procurement experience is gained, and might vary based on the expected risk of contracts already signed.

Provide Delivery Flexibility, and Allow Unbundled Renewable Energy Certificates (RECs)

California's renewable energy delivery requirements were recently modified to allow for a broader range of delivery locations. In July 2005, the CPUC (in D.05-07-039) *required* the state's utilities to accept bids from out-of-service-territory projects that would deliver their electricity *anywhere* within the California ISO system, and *allowed* the utilities to accept delivery anywhere in California. This change is encouraging, but additional modifications should be considered to further promote supply competition, *especially* if a more aggressive 33 percent target is implemented.

We first recommend that the CPUC specifically allow renewable developers to offer shaped or firmed products, as long as renewable electricity is delivered *into the state*. This would allow utilities to purchase RECs bundled with electricity delivered to the utility's service territory, but delivery of that electricity would not necessarily be coincident with the hour-to-hour production of the renewable generator. This places re-marketing and congestion risks on the renewable developer, but also allows the developer to deliver a shaped product to the utility that may avoid the need for costly transmission additions between utility service territories. It also allows the developer to provide a product that better meets utility needs, including products that better meet emerging resource adequacy requirements. We understand that the CPUC intends to explore the issue of shaped or firmed products later this year, and we assume that rules allowing such products will be developed for the purposes of the 20 percent RPS.

In the near to medium term, we also recommend that the CEC find that out-of-state renewable generators that deliver to a nearby but out-of-state market hub or substation are eligible under the state's RPS if the utility purchaser commits to arranging for transmission from that hub or substation to an in-state location. Eligibility determinations for out-of-state generators are vested with the CEC, but whether such a change requires legislative action is somewhat unclear. Additionally, though recent CPUC rules require utilities to accept bids for renewable delivery anywhere within the California ISO, such bids may be disadvantaged in the bid evaluation process, as utilities are allowed to consider potential re-marketing, swap, and congestion costs and risks in ranking bids. No experience has been gained as of yet with these evaluation practices, but if the utilities' evaluation of such bids appears onerous and likely to encourage higher-cost, in-utility-service-territory projects, then the CPUC should consider stepping in to standardize the evaluation of such bids.

California is one of a few states that do not allow unbundled RECs to qualify under its RPS (other examples include Minnesota and Iowa), and is the only state in which competitive ESPs must comply that does not also allow unbundled RECs. Though unbundled RECs are not a panacea to the very real transmission constraints that currently exist, use of unbundled RECs may help facilitate RPS compliance especially for the state's ESPs and CCAs (and for those utilities with constrained transmission ties with the rest of the state). To achieve a 33 percent RPS, we therefore believe that the state's policymakers should *consider* allowing unbundled RECs for renewable electricity that is delivered to the state. Whether the CPUC has the authority to allow unbundled RECs, absent legislative change is somewhat unclear.[72]

There may, however, be limits to the appropriate use of unbundled RECs, especially those sold in short-term markets. Perhaps most importantly, renewable energy generators have historically required long-term contracts. While some merchant renewables development activity now occurs in other states, it remains somewhat unclear whether short-term trade in RECs would provide cost-effective support for new renewable energy development in California. Additionally, we acknowledge that the CPUC's earlier order allowing out-of-service-area delivery, and perhaps extending that to allow shaped or firmed products, may already alleviate the barrier of inter-utility transmission constraints, and that the incremental benefit of truly unbundled RECs will be lessened to some degree.

Nonetheless, we encourage continued discussion of the use of unbundled in-state RECs under the California RPS, especially for smaller LSEs. To ensure that the state benefits from REC transactions, we also believe that the state's policymakers (whether the CPUC, or the state legislature) should remain open to establishing reasonable limits to the use of unbundled RECs, such as percentage limits or minimum contract term requirements.[72] Additionally, we encourage serious discussion of whether and how SEPs might apply to REC transactions (assuming that SEPs remain, which as noted later, we do not recommend). Allowing unbundled RECs but not allowing REC transactions to access SEPs may provide limited added flexibility, because purchasers may sometimes prefer higher-cost bundled transactions that can receive SEPs to lower-cost REC transactions that cannot.[72]

Allowing unbundled RECs from outside the state would clearly require new legislation. With an aggressive 33 percent target, however, we also believe that it may ultimately be necessary to provide additional delivery flexibility to out-of-state generators. This may be especially the case in the event that resource, permitting, or transmission constraints hinder in-state development. In so doing, however, the state will lose at least some of the "in-state" benefits of renewable energy development such as the hedge benefits renewables can provide against natural gas price volatility.[72] On the other hand, allowing greater competition from out-of-state renewables may exert downward pressure on renewable prices.

If out-of-state RECs are allowed, the state will need to ensure that the carbon reduction benefits of the out-of-state renewable generation supported by California are assigned to the state. Because of the complexities of these considerations, we do not recommend that the state legislature immediately loosen its delivery requirements for out-of-state generators (and again, we recognize that allowing such transactions to qualify under the RPS would require legislative action). Instead, we recommend that the CPUC, CEC and the state legislature stay attuned to delivery issues, and that the state legislature alter the present requirements as deemed necessary in the future.

Develop an Appropriate Mix of Incentives and Penalties

To achieve a 33 percent renewable energy target the state's IOUs, ESPs, and CCAs must consistently and aggressively pursue renewable purchases. An effectively designed system of penalties is crucial in this regard.

The CPUC has already developed a set of penalties and flexibility mechanisms that apply to utility RPS compliance obligations. Thus far, we see evidence that the state's IOUs are taking their RPS requirements seriously. Nonetheless, we assume that the CPUC will remain vigilant, and will be willing to apply penalties in cases of clear non-compliance. If such efforts are insufficient to motivate compliance in the future, then the CPUC may wish to consider clarifying or revising its system of penalties and flexibility mechanisms. This might first involve further clarifying the *specific* conditions that must be met for an IOU or ESP/CCA purchase requirements to be waived under the flexible compliance rules; the current rules for the IOUs are somewhat vague on this important issue. It could also involve raising the penalty cap above its current level of $25 million a year, though we currently see no evidence that this penalty level is insufficient.

We do see some evidence of differences in perception between the CPUC and some stakeholders about the likely willingness of the CPUC to actually apply such penalties. Clarification of the specific conditions under which penalties would or would not be applied would help to eliminate any uncertainty and misperceptions that presently exist.

Achieving a 33 percent target will undoubtedly require substantial transmission investment. Those investments, and the renewable energy projects that follow, may well occur in a "lumpy" fashion, making it difficult for the state's IOUs, ESPs, and CCAs to increase their renewable purchases in a steady and consistent manner. To accommodate this reality, the CPUC may want to offer some additional compliance flexibility, consistent with RPS statutory requirements. As one example, under the authority provided by SB 1078[72] or through augmented authority provided by future legislation, the CPUC may wish to provide *up-front* approval for a utility to systematically under-comply with the RPS in the event that that utility is able to demonstrate: (1) a major transmission investment is underway to access a remote renewable resource area, and (2) that the utility has contracted with renewable projects in that area that are highly likely to come on line once the transmission investment is complete, and that these projects are sufficient to meet the utility's past and present purchase obligations.[72]

Meeting a 33 percent target requires willing buyers. Under the present regulatory structure, the state's utilities may profit from owning renewable energy assets (through a return on rate-based facilities), but purchases of renewable electricity from third parties will generally provide no such opportunity. We recommend that the CPUC *consider* developing a system of incentives that provide the IOUs some profit for achievement of the 33 percent goal. The CPUC, in a December 2004 decision on resource procurement, determined that the state's IOUs can be compensated for the costs of debt equivalency. Perhaps this is sufficient. And we certainly recognize that the development of additional profit incentives is challenging and controversial, and that strong arguments can be made on both sides of this issue. We also note that the CPUC has already begun to wrestle with these issues in its general procurement proceeding. Nonetheless, while not pre-judging the outcome, we believe that continued attention to this issue is warranted, especially in the context of a more aggressive 33 percent goal.

Eliminate MPR-SEP Structure

As the state seeks to achieve a more aggressive 33 percent RPS, we recommend that the legislature consider the elimination of the present MPR-SEP structure. Such a change would clearly require legislation, and should in no instance jeopardize current utility procurement activities conducted to achieve the 20 percent requirement.

The existence of SEPs makes the California RPS unique, but less recognized is that SEPs create perverse incentives. Because utility payments are capped at the MPR, utilities may be indifferent to the cost of contracts that *exceed* the MPR, and may therefore select projects with an undue emphasis on, for example, portfolio fit at the expense of total societal cost. The result may ultimately be higher-cost renewable contracts and a premature draw down of SEP funds. The fact that renewable energy contracts to date have come in below the MPR has limited these perverse incentives, and regulatory approval of renewable energy solicitations and evaluation protocols, PRG oversight, and CPUC contract pre-approval can also counteract the impact of these incentives. But, each of these regulatory measures results in added complexities and burdens. This added complexity may in turn slow the state's progress towards achieving its aggressive renewable energy goals.

The existence of the MPR-SEP structure also: (1) may negatively affect bid prices and thereby inflate the cost of the RPS to the state's electricity ratepayers; (2) leads to questions over the certainty and financeability of state-administered SEPs to renewable generators; (3) complicates the issue of unbundled RECs (specifically, whether such transactions can receive SEPs); and (4) creates potential coordination challenges between the CPUC and CEC. While each of these concerns can be addressed, to some degree, we question the fundamental value of the MPR-SEP construct, especially in an era of high natural gas prices where renewable energy contracts appear cost effective.

Eliminating the MPR and SEPs, and allowing utilities to recover prudent renewable energy costs in retail rates (like most other states' RPS policies), would not absolve the CPUC of its policy and procurement oversight responsibilities, but it would make those responsibilities somewhat easier to manage.[72] Eliminating the MPR-SEP structure would also help alleviate some of the other concerns with that structure, as reported above. The primary stated advantage of the current MPR-SEP structure – the establishment of a cap on overall program costs – can easily be accommodated through other means (many other states, for example, have developed cost caps without a MPR-SEP structure).

To avoid interruption of a program that is beginning to show signs of working, we recommend that the state legislature revisit the MPR-SEP structure during deliberations on a 33 percent RPS. We also recommend that should such a change be made, the present system remain in place until the new system is fully operational, and that all care is made to ensure a seamless transition.[72]

Some of these recommendations are analyzed further in Section IV (cost and rate impact scenarios) and modified further based upon this analysis.

DISTRIBUTED RENEWABLE ENERGY SOURCES AND VOLUNTARY RENEWABLES MARKETS

In this section we discuss other types of activities and programs that could encourage greater use of renewables beyond that supplied by the RPS program in order to help meet greenhouse gas reduction goals. Specifically we assess strategies to encourage distributed generation and the voluntary renewable energy market both of which have the potential to increase clean, non-emitting electricity supply.

Distributed Generation – Photovoltaics (PV)

As background, California is currently the third largest PV market in the world, behind Japan and Germany respectively. The California PV market has grown by about 60 percent a year for the last five years in a row in response to favorable DG policies and public support for renewable technologies overall.[73] By comparison, the global PV market has grown by about 35 percent between 2003 and 2004 though total market share in Germany -- 39 percent, and Japan -- 30 percent, continue to eclipse those of California -- 5 percent, due to early government investment in PV technology and sustained, multi-year policy commitments.[74]

With the failure of SB 1, the Governor's Million Solar Roofs Legislation, responsibility for maintaining consistent momentum falls to the CPUC that will issue a proposed decision on implementation of a customer incentive program for solar. This new, combined, customer incentive program for solar (CSI) would replace the CPUC Self-Generation Incentive Program (SGIP) and the CEC's Emerging Renewable Program (ERP). The program objectives include:[75]

- Add clean, distributed electric generation to California's peak demand resources.
- Reduce economic risk by diversifying California's energy portfolio.
- Lower the burden of expanding and maintaining the State's transmission, pipeline, and distribution systems for electricity and natural gas.
- Reduce the production of greenhouse gas emissions from California's electric sector

[73] / *Assigned Commissioner and Administrative Law Judge's Ruling Seeking Comment on Staff Solar Report.* OIR. 04-03-017, Figure 2 page 8.
[74] / *MarketBuzz: Annual World Solar Photovoltaic (PV) Market Report*, March 2005.
[75] / "Assigned Commissioner and Administrative Law Judge's Ruling Seeking Comment on Staff Solar Report," CPUC 6.14.05, p. 4 & 5. http://www.cpuc.ca.gov/word_pdf/RULINGS/47004.pdf

- Demonstrate California's long-term policy and fiscal commitment to solar energy production.
- Establish a program plan under which solar products and providers can transition to a market without state incentives.
- Include protocols to allow residents of affordable housing to utilize solar technologies they might not otherwise be able to access.

In addition, the joint CPUC and CEC staff report made a series of specific recommendations that were released for comment on June 14, 2005. We expect a Proposed Decision from the CPUC by mid-November. This joint effort by the CPUC and the CEC is anticipated to not only sustain momentum in the State for solar but also to significantly increase customer demand and industry supply in order to reach a point where photovoltaic energy emerges as a cost-effective option for customers without the need for further financial incentives.

PV can offer a substantial fraction of new generation. In a business-as-usual scenario, California can expect to receive a 5 to 10 percent share of the global PV market.[76] Under a more favorable scenario with sustained support for PV, California might expect to install as much as 30 percent of the global PV module output.[77] This could amount to California's PV market share rising from 40 MW/yr to 2,000 to 3,000 MW/yr by the time 1000 MW/year manufacturing plants are in production. As a result, estimates for the amount of PV capacity that might be installed in California between 2010 and 2020 could be at the low end 3,000 to 6,000 MW, and could be as high as 10,000 to 15,000 MW when there is a step change in the average size of PV manufacturing facilities.

PV offers a range of valuable public benefits even though it is not currently cost competitive with retail electricity rates. It can be installed without need for transmission investment, avoids line losses associated with central station generation, adds to diversity of the generation system and is often correlated with peak load (avoiding the highest cost fossil peak generation and reducing a wide range of pollution associated with fossil generation including greenhouse gas emissions). PV began as primarily an off-grid application, but more recently has become predominately an on-grid technology, capable of producing power at either household or commercial scale. In California, many megawatt scale systems have been installed by public and private customers.

According to the PV experts interviewed for this report,[78] PV is expected to be *cost competitive with retail electricity rates* within ten to twelve years. Drivers for cost reduction include incremental improvements in the technology, manufacturing and installation scale-up, and the potential for a major technology breakthrough. Evidence of industry confidence in that timeframe is found in the industry's support for a declining

---

[76] / In 2004 CA had approximately 5 percent of global installations, Ibid.

[77] / Though there has been a shortage of silicon feedstock that has caused reduced module production worldwide in 2005, PV experts interviewed for this paper still believe that with a sustained program of support for California's PV market that global PV manufacturers will want to be involved in California and will supply up to one third of their output in order to be a player here.

[78] / Julie Blunden of SunPower, Carrie Smith of PowerLight, and Tom Starrs of BEF.

rebate program like that proposed by the Governor's Million Solar Roofs Initiative and research by third parties.[79] Escalating fossil fuel prices, leading to higher retail electricity prices are also expected to close the gap between retail electricity rates and the cost to the consumer of installing PV. Moreover PV offers a useful "hedge" against not only fossil fuel price increases, but also more stringent future environmental regulations that could increase the cost of electricity from the grid where that is supplied by fossil plants. If the PV DG program is widely successful in bringing down costs, we will not have to worry about making solar happen, customers will do that for us, just like they did with cell phones. If a 33 percent RPS includes or adds a solar carve-out that is additive that may further accelerate the customer-driven market.

Though future cost reductions of this magnitude cannot be assured, the next five years are critical for public policy to set the stage to encourage PV industry investment in increased manufacturing levels, and to take advantage of other technology step-changes. During this period, a rapid increase in manufacturing may reduce costs to the consumer, optimize investment opportunities in on-site generation, educate the public about the benefits of the technology applications, and create an international technology hub in California similar to the boom in the micro-chip economy. Should California's PV market falter between now and 2010, lower cost PV systems may lag behind other global markets, delaying the benefits associated with locally produced and emission free electric generation and potentially closing the window of opportunity for California to establish itself as the US PV business hub.

Net Metering

Net metering is a policy whereby on-site renewable generators receive a credit on their utility bills for excess power they generate but do not use on-site.[80] With net metering, during times when the customer's on-site generation exceeds his or her use, electricity from the customer's facility to the utility offsets electricity consumed by the customer at another time. In effect, the customer is banking the excess generation to offset electricity that would have been purchased from the utility at the retail rate. *Because PV systems tend to produce most of their excess power during peak months and peak hours, another way to think about net metering is that the net generating customer is lending energy to the rest of the customers during periods that usually correlate with higher demand, and retrieving that power during periods that usually correlate with lower demand*.

Net metering treats on-site generation and use in a manner similar to demand reduction programs. However, the State limits the amount of net metering that is allowed on the system (though demand reduction is not limited). The present limit of 0.5 percent could be exceeded by customers in PG&E and SCE's territories within a few years. The net

[79] / Maya Chaudhari, Lisa Frantzis, Tom Hoff; "*PV Grid Connected Market Potential under a Cost Breakthrough Scenario*, "The Energy Foundation, September 2004. Marvin S. Keshner, Rajeewa Arya; "*Study of Potential Cost Reductions Resulting from Super-Large-Scale Manufacturing of PV Modules."* NREL, October 2004.

[80] / In California, this credit can be carried for up to 12 months at which time, if the excess is not used it is granted to the local utility.

meter cap was raised to 50 MW (roughly 1 percent) for SDG&E in legislation passed and signed in July 2005 (SB 816). Should PV costs decline to be competitive with retail rates, the demand for on-site PV would run head-on into net metering cap problems.[81] This situation could stifle the installation of PV systems, or property owners could simply go around the utility by installing battery back-up for their systems and disconnecting from the grid altogether. Neither of these actions is desirable or in the best interest of the state's ratepayers because it would reduce the amount of emission free, peaking electricity available to meet California energy needs.

The stated reason for the cap is that DG/PV creates the need to reallocate some fixed costs to other ratepayers due to a decline in projected revenue. For example, transmission/distribution (T&D) costs are largely fixed for the utility. Lower revenue due to PV or energy efficiency offsetting customer demand will create the need to increase rates relative to an alternative scenario to collect the fixed T&D costs over a smaller number of kilowatt-hours. From a policy perspective, since the DG system owner uses the T&D system for storage of their excess power, there are some associated costs that might legitimately be charged to him/her (based on a per kWh cost recovery basis) that are now being avoided On the other hand, the other utility customers are often receiving power during peak or mid-peak times and during peak summer months while the PV owner may be taking back 50 percent of that power during off-peak months and off-peak hours.[82]

There are two strategies that could be used together or separately to eliminate the need for a cap on the amount of net metering allowed:

1. *Establish a statewide PV Tariff:* Develop a state-wide PV tariff (analogous to the PG&E A-6 tariff) that is based on the value of the power at the time of delivery) that can supplement or replace the present net metering tariff structure. Any change in metering and tariff structure should fairly account for the DG owner's contribution to peak load without creating unfair cost allocations.[83] The tariff should also reflect the cost reducing effect DG can have on transmission and distribution expenses. In addition, utilities might be encouraged to develop special DG rate incentives for areas where DG deployment can reduce or delay new transmission and distribution expenses.

2. *Institute an equitable T/D fee (or some other cost recovery strategy) on net metered DG power that uses the T/D system to store excess.* Further research is needed to better understand the level of cost reallocation occurring between net metered customers to other customers.[84] Any cost reallocation occurring today could be mitigated or reversed either through a T&D fee or by changing the

---

[81] / We estimate that net metered PV could add 1 to 5 percent additional renewables to the system.
[82] / See CPUC testimony by Americans for Solar Power, 4/13/05, Exhibit LSS-7.
[83] / A move to this type of rate structure would need to be done carefully so as not to disrupt existing PV markets by undermining the basis for current PV investments. Consistent regulatory policies are critical to sustained development. Nonetheless, incremental changes to the program on a <u>prospective</u> basis could improve the economics for both the customer and the utility.
[84] / An Oklahoma study resulted in a charge of $0.00017/kWh for transmission handling.

method by which T&D costs are being recovered. Such mechanisms might be different for residential customers than for commercial/industrial customers.

Revenue Loss: In this respect, net metering is identical to demand reduction and has been decoupled so, though there remains a revenue loss, there is no loss of profit to the utility.

DG Interagency Working Group: Members of the DG community have expressed concern that stakeholders have been left out of the interagency working group supervising the Self-Generation Incentive Program. They felt they could better support the implementation of activities and improve efficiency of PV programs if they were involved earlier in the decision-making process and able to provide insights into what is feasible in the marketplace. Specifically, PV Now proposes to set up a working group for the California Solar Initiative that would directly include industry and solar stakeholders.

Property Rights to Environmental Benefits from Distributed Generation: It is important that the property rights to the environmental benefits from distributed generation be clear and unambiguous. CPUC Decision 05-05-001 granted PV RECs to the customer. It is important that this decision not be disturbed and that customers be able to make informed decisions concerning the disposition of future PV RECs as they relate to PV incentive programs.

RPS Carve-Out: A renewable DG carve-out in the RPS expansion, in addition to the current customer incentive program, could amplify and accelerate solar penetration in California. New Jersey and several other states[85] use this combination and these states are beginning to have success in growing the PV industry. For example, the utilities could have a 33 percent RPS target for bulk power and a 3 percent target for DG (approximately 3000 MW of DG). The 3 percent DG target would have to include some incentive for participation such as a fixed price contract for PV RECs on a first-come, first-served basis or some other type of incentive. The utility might also receive some incentive for exceeding the target. Such a carve-out will be additive and may accelerate the customer-driven market.

On-Site Generation From Agricultural Waste

There is the potential for approximately 1700 MW of on-site generation using agricultural-based fuel sources such as animal waste, crop residues and possibly some energy crops from California's agricultural sector.[86] However, less than 10 percent of that potential is likely to be realized without additional incentives. Increased pressure to clean up waste (e.g. from animal manure) as well as air quality enforcement of NOx and possibly greenhouse gas emissions is encouraging facility managers to consider measures

[85] / In the west, Arizona 1.1% in 2004-2012, Colorado 2% from DG PV, Nevada 5% of total RE (includes both PV & CSP), and Texas (solar and biomass must account for 500 MW).
[86] / [Get exact citation from CEC Strategic Value Analysis]

such as on-site generation that can reduce harmful outputs as well as provide a valuable service and some additional revenue. However, the economics for these small, distributed generation facilities have historically limited investment in these projects. Production-based incentive programs and participation by third party developers (as happened in the cogeneration market) might be the key to realizing a larger amount of generation from this sector.

Recommendations (DG Market):

Maintain Stable DG Support

Over the next five years, develop and maintain stable state support for DG/PV (e.g. help keep PV growth at ~30 percent) in order to maximize the amount of cost-effective PV available 2010 to 2020.

Maintain Net Metering

Maintain the existing net-metering program to support a stable market environment. Adjust the program and the use of a program cap as appropriate to changing circumstances

Implement PV Tariff

Develop a state-wide PV tariff (analogous to the PG&E A-6 tariff) that is based on the value of the time of delivery) that can supplement or replace the present tariff structure. There could also be a regulatory reward side for IOUs that develop innovative programs that take advantage of DG/PV to reduce system costs of grid operation while stimulating greater use of PV.

Inter-agency Working Group

Include the PV industry in the inter-agency working group for self-generation.

Clear Rules for DG Customers[87]

Continue to allow customers with DG to have clear property rights to renewable energy certificates unless they explicitly deed them through contracts to another party. This will allow, customers with distributed generation systems in the future to make informed choices regarding the disposition of the renewable energy certificates (REC) from their systems under various incentive scenarios. And this clarification will provide present owners of DG systems a clear understanding of the market choices available to them without the risk that they have misinterpreted the CPUC rules.

[87] / Though the CPUC attempted to clarify this position in D._____, there unfortunately remains a large amount of disagreement and confusion concerning what the decision actually meant.

Agricultural DG Incentive Program

Consider development of an agricultural DG incentive program (e.g. special rates for excess power generated on-site using agricultural waste fuel).

Aggregated DG RPS Priority or Alternative DG/RPS Target

Consider giving priority to aggregated power from distributed generation in one or more of the utility RPS solicitations or, as an alternative, establish a separate DG/RPS carve out.

The Voluntary Renewable Energy Market

Voluntary Market Overview

Voluntary renewable energy markets include: *Renewable energy* sold directly to retail customers in restructured electricity markets, renewable energy *certificates* sold to retail customers in both restructured and monopoly markets, renewable energy that is sold to consumers through *utility green pricing programs*, and renewable energy *certificates* that are translated into pounds of carbon equivalents and sold in voluntary *carbon markets*. It is estimated that in 2004, approximately 7 million MWh[88] of renewable energy was sold in voluntary markets in the United States. This equates to approximately 7 million tons of carbon displacement.[89] The voluntary market is forecast to grow to 20 million MWh by 2010 (20 million tons of carbon displacement).[90]

In several markets, notably PJM and the Pacific Northwest, voluntary markets have been a key driver in the development of new renewable facilities.[91] These markets generally operate without government subsidies, so the environmental benefit of a voluntary renewable market is in addition to any benefit that governmental action produces.

Voluntary renewable markets are only eight years old, but experience to date demonstrates their promise in supporting substantial renewable development. Initially, voluntary renewable energy markets were limited to states that allowed direct access (i.e. restructured states) and to utility green pricing programs. With the advent of RECs, voluntary renewable energy markets are growing rapidly in many regions, and are expected to be a larger driver for new renewable energy additions in the future. These

[88] / Based on power pool regional average emission rates.
[89] / These numbers do not include renewables sold in regulated electricity markets or renewables used to meet utility compliance with renewable energy mandates such as Renewable Portfolio Standards (RPS).
[90] / http://www.eere.energy.gov/greenpower/resources/pdfs/0705_naw_ehlb.pdf.
[91] / "New" refers to facilities that have been built since the restructuring of an electricity market or as part of a renewable "green-power" program.

markets have increased by 1000 percent in the past five years and we expect them to continue to increase by 50 to 60 percent each year in the near future.[92]

Renewable energy and renewable energy certificates are purchased in voluntary green power markets both to reduce greenhouse gas (GHG) associated with a company or individual's electricity purchase as well as to offset GHG produced by commercial, industrial, institutional and residential activities. The non-residential sector is the fastest growing and is the sector that is especially interested in the carbon offset benefits of renewables. Renewables are used to offset carbon produced by manufacturing/fabrication, food processing, carbon resulting from travel (including air and auto travel), natural gas usage, etc. Renewables can also be used to offset smaller fossil-fueled self-generation (not included in the electricity carbon cap). The voluntary market in California could substantially supplement GHG reductions that occur as a result of mandatory programs. The voluntary market in California includes: (1) RECs marketers; (2) Green-pricing programs (presently only offered by public utilities but could be offered by IOUs); (3) CCAs that go beyond the RPS mandate; and (4) customer sited renewable generation (discussed in the previous section).

Green Pricing Programs

Green pricing is a voluntary option offered by electric utilities that allows customers to support investments in renewable energy beyond what might be mandated by the State. Through green pricing, participating customers volunteer to pay a green rate (typically a premium above the cost of regular electric service) on their electric bill to cover the extra cost of the renewable energy they purchase.

However, for some utility programs, rather than paying a fixed premium above their regular rate, the customer pays renewable energy tariff or a fixed charge per kWh to purchase renewables to supply some portion of their power supply. In this example, the regular generation rate per kWh is replaced by a green power tariff, rather than having the green power fee as an add-on to the normal tariff. In this way, the green power customer can shelter some or all of his/her electricity bill from price fluctuations related to fossil fuel rates (typically through a 5 to 10 year contract). Austin Energy and others have used this effectively to attract non-residential customers. This hedging option is particularly attractive to customers that are risk averse to electricity price fluctuations such as commercial building owners and manufacturers where electricity is a significant input to their product. A 33 percent RPS can provide this type of price hedge for up to one third of the utility's portfolio while a green pricing option offered by the same utility can allow customers to hedge some or all of the rest of the portfolio.

Some Green Pricing programs also offer distributed generation (i.e. PV systems) through a lease/purchase or some other type of financial arrangement. These programs can help

[92] / *Green Power Marketing in the United States: A Status Report.* Lori Bird & Blair Swezey, NREL/TP-620-38994, October 2005.

customers finance the up-front costs of DG as well as provide a service warranty and confidence in the quality of the system being purchased.

Even with a 33 percent renewable energy target, there are electricity customers who would be willing to pay extra, if necessary, to go beyond that target (the City of Palo Alto's green pricing program currently has 13 percent residential enrollment). Add to that the value of renewables if offered as a hedge against volatile natural gas prices, and financing options for PV/DG, and Green Pricing Programs could become very popular in California. It is possible that if California's investor owned electric utilities offered well designed Green Pricing programs or Green Tariffs this could add 1 to 3 percent additional renewable sales above the State RPS mandate.

Recommendations (Voluntary Markets):

<u>Carbon Benefits for Renewable Generators</u>

Support voluntary renewable energy markets by ensuring that renewable energy generators are able to pass along the carbon benefits associated with their power generation to their customers. This includes ensuring renewable energy and RECs from projects located in other states but sold into the California market are able to transfer their carbon benefits to the California purchaser.

<u>Additionality of Voluntary Market</u>

Ensure renewable energy sold in voluntary markets is additional, accounted for separately and not counted toward compliance with mandatory targets.

<u>Green Pricing</u>

Encourage or require State IOUs to offer green pricing/tariff programs that incorporate best practices:

g. Are based on new renewable generation facilities
h. Are additional to utility mandates
i. Allow customers to hedge against fuel price fluctuations
j. Allow the use of regional RECs as appropriate
k. Encourage the use of contracts for differences for RECs
l. Keep any above market prices consistent with actual renewable energy costs and only include reasonable fees for services

Community Choice Aggregation

On the face of it, Community Choice Aggregation (CCA) programs would need to meet the same RPS goals as would all other utility customers therefore why discuss them under a section on Voluntary Programs? The reason for including them here is that interviews with key decision-makers considering Community Choice Aggregation in California communities indicate that a major driver is the ability of the community to go beyond

California RPS targets. Several communities believe they can go to 50 percent renewables at the same or lower cost than the IOUs can do for a 33 percent level.[93] We have no basis for knowing how many California communities may ultimately decide to join the Community Choice Aggregation program, but to the extent there are some CCA programs, we anticipate they may exceed the 33 percent renewable energy level by 10 to 15 percent. A conservative estimate would be 300 MW of additional renewable capacity from CCA programs (approximately 0.3 percent above the 33 percent mandatory target).

SUMMARY

In summary, it is possible for California to achieve an even higher level of renewable energy penetration than 33 percent by adding the amount of renewables that could be achieved in California's voluntary markets. We believe that with a cost breakthrough of some type that makes PV competitive with retail electricity rates and carefully crafted incentive programs for on-site biomass facilities, an additional 3 to 5 percent of electricity demand may be served by on-site distributed generation. Moreover, we believe another 1 to 3 percent could be delivered through utility green pricing programs, and other voluntary renewable energy sales. There are many caveats that go along with these projections of voluntary market contributions but they are possible to achieve under the right circumstances.

[93] / In great part due to the use of revenue bond financing for their renewable project supplies.

INTEGRATING WITH THE STATE'S GREENHOUSE REDUCTION TARGET

In Executive Order S-3-05 announcing California's greenhouse gas emission reduction targets, the Governor indicated that 33 percent renewable energy by 2020 was a key element for reaching the greenhouse gas reduction targets.[94] This section discusses how to smoothly integrate the 33 percent renewables target with the Greenhouse Gas (GHG) Reduction Program and other related State programs.

Meshing With Greenhouse Gas (GHG) Reduction Target

Meshing the 33 percent renewable energy target with electricity sector greenhouse gas reduction targets can be accomplished in several ways: (1) Codify the 33 percent RPS target and move to fully implement the mandate; (2) integrate the greenhouse gas reduction target, as well as the renewable energy and energy efficiency goals into the utility resource planning and procurement process and implement them in an integrated approach; (3) translate the greenhouse reduction goals into an electricity sector cap and trade program; or (4) some combination of the above.

1. Codify the 33 percent RPS and implement the mandate
It is assumed by some that the RPS (as well as energy efficiency and the million solar roofs program) will result in the emissions savings required to meet the electricity sector greenhouse gas (GHG) reduction targets. Unfortunately, that is not necessarily the case primarily because reaching these targets depends upon what other resources are being procured and used, in addition to renewables, to meet California's electricity load. For example, if the energy efficiency savings projected in the plan are not met, then more renewable energy resources would be required to meet the forecasted reductions. Or, more importantly if large quantities of fossil generation (without carbon sequestration) were acquired, 33 percent renewable energy generation could be wholly insufficient to offset these increased carbon emissions attributable to the electricity sector. Even if a carbon adder or performance standard[95] is used in evaluating other energy purchases, the

[94] / Executive Order S-3-05 by the Governor of the State of California, June 1, 2005. http://www.governor.ca.gov/state/govsite .
[95] / On October 6, 2005 the CPUC passed a resolution directing Staff and General Counsel to investigate adoption by the PUC of a greenhouse gas emissions performance standard for all IOU procurement contracts that exceed three years in length and for all new IOU owned generation. The resolution also directs Staff to investigate offset policies that include a reliable and enforceable system of tracking

actual results are dependent upon the size of the adder -- with a low carbon adder or performance standard allowing greater quantities of fossil generation and thus greater quantities of GHG emissions than a high carbon adder would do.[96] **Therefore, though important, neither renewables nor energy efficiency targets are sufficient in themselves to ensure that electricity sector GHG reduction targets will be reached.**

2. Integrate GHG reduction targets as well as renewables and efficiency goals into general utility resource planning

This is a more effective and comprehensive approach than simply implementing the 33 percent renewables goal, particularly if the GHG reduction targets are operationalized as criteria that can be used to evaluate various supply and demand scenarios.[97] Such an approach might require utilities to present a plan for meeting specific emission targets and hold their shareholders responsible for the risk/costs associated with not meeting these goals. As part of the resource planning process, utilities could assess the overall load being served and identify not only new incremental resources but also which plants are to be retired based on emission profiles. Renewable energy can be thought of as filling certain gaps in the total system needs not as just an incremental supply resource. There might be changes in the general operation of fossil plants that would improve the efficiency of the system and enhance the use of larger quantities of renewables.[98] This strategy is broader than a general RPS target and would be much more specific in comparing the costs and benefits of various supply and demand reduction options.[99] **One problem with the resource planning approach alone is that it only addresses the resource plans of the investor owned utilities.** This approach could leave out ESPs/CCAs as well as public utility companies. Since the GHG reduction targets are statewide, a similar process would need to be undertaken by customer owned electric utilities, possibly in conjunction with filings by POUs to the California Energy Commission.[100]

3. Implement a GHG Cap and Trade Program

Though using an integrated resource planning approach could be effective in moving toward the initial GHG reduction target, as the State moves to more aggressive emission reduction targets in future years, a mandatory program such

---

emissions reductions. CPUC Policy Statement investigating the potential adoption of a greenhouse gas emissions performance standard for IOU procurement. October 6, 2005, Agenda ID: 4958.

[96] / www.pewclimate.org/states.cfm. http://psc.state.wy.us/htdocs/subregional/Final Report/rmatsfinalreport.htm, Appendix F.5.

[97] / Id -- #2.

[98] / See sections II and III of this report.

[99] / This report has not attempted to evaluate the carbon reduction savings attributable to a 33 percent RPS. Some accommodation would need to be made for the emissions from any gas turbines used for resource adequacy purposes. Moreover, as allluded to in other parts of this report, there may be operational changes in the rest of the system that could not only provide greater operational flexibility but also result in GHG reductions. These are they types of questions that could be addressed through a comprehensive resource planning process that integrates GHG reductions into the criteria used to evaluate supply/demand options.

[100] / The above CPUC resolution also calls upon publicly-owned utilities to reduce GHG emissions and adopt goals and standards that are comparable to what the IOUs are required to meet.

as a GHG Cap and Trade regime is likely to be more effective than either of the options described above since it would incorporate dates and targets for specific compliance as well as penalties for non-compliance. The CPUC is presently investigating such an approach through their participation in the Climate Action Team.

Should a Cap and Trade (C&T) program be adopted, commonly a modeling exercise would be undertaken to forecast the greenhouse gas emissions likely to be produced by the electricity sector under a business as usual (BAU) scenario. That scenario would include any GHG reductions associated with meeting an existing RPS mandate as well as savings from renewables and energy efficiency contained in approved utility resource plans. To the extent that these actions were insufficient to meet stated GHG reduction targets, a cap would be established and a methodology developed for allocating GHG allowances under the program. To the extent that the C&T program was well designed and able to avoid serious leakage problems, this is probably the most efficient method for actually reaching GHG targets. However, a C&T program is more complex to administer than an integrated resource planning process and has significant political hurdles to overcome.

4. Implement a combination of the above

A renewable portfolio standard needs to be integrated into overall utility planning rather than being viewed as a side decoration. An IRP process used to integrate RPS and energy efficiency targets with a performance based greenhouse gas reduction standard is fairly easy to put into place but difficult to administer on an ongoing basis, while a cap and trade program is likely harder to agree to up front but may be very efficient in the long-term.

In fact, all three of the strategies discussed above could be integrated to achieve the desired results. The 33 percent renewables target could be either an RPS mandate or a planning target.[101] An integrated resource planning approach (that incorporates either the RPS or renewables target) might be used as a transition strategy while a GHG Cap and Trade program is being approved and put into effect. For both equity reasons as well as the fact that the GHG reduction goal is a statewide goal, customer owned as well as IOU, LSE and CCA electricity servers should have to meet the same GHG reduction requirements and timelines. This likely requires legislation.

[101] / Since mandates usually include penalties for non-compliance, an RPS may be more likely to achieve its goal than a simple planning target unless the planning target is strictly enforced.

Other Program Issues

Ensure That a Cap and Trade Program Does Not Undermine the Viability of the Voluntary Market for Renewables or the Benefits Associated with Additional Renewable Projects

Without recognition in a state/region/federal cap and trade program, voluntary renewable energy markets are at risk and mandatory programs cannot properly quantify the volume of carbon dioxide reduced as a result of RPS and voluntary market implementation. Many current buyers of renewable energy do so because it helps them reduce the level of CO2 in the atmosphere from electricity. If there is a cap, the State should allocate allowances to entities selling renewable energy into the voluntary market so they can retire allowances in support of claims that such sales avoid CO2 (or the state could retire allowances indirectly in support of such claims). Failure to do this would undermine the voluntary market and make it more difficult to meet the cap. Moreover, to the extent that renewables are cost effective supply sources beyond RPS targets, they need to receive allowances for the carbon avoided by these facilities. It is critical that the connection between renewables and carbon emission reductions be made explicit in order to encourage the level of renewables necessary to meet the desired GHG targets.

GHG Reduction Credit for RECs from Out-of-State Projects

In earlier sections of this report, we suggested the state consider allowing out-of-state RECs to be used for RPS compliance in the 2010 to 2020 timeframe. This only makes sense if the State gets to count the GHG reductions from those purchases. In order to avoid double counting and to ensure that California can receive credit for the GHG reductions associated with out-of-state REC purchases (should they choose to do so), it is important that there be adopted a standard protocol for handling these attributes in other states selling RECs into California. This may be facilitated by the Western Governor's Association and the California Energy Commission through WREGIS and the North American Association of Issuing Bodies (NAAIB)[102] to ensure that purchase of out-of-state RECs carries with them the associated greenhouse gas reduction benefits.

Western Renewable Energy Generation Information System (WREGIS)

WREGIS is the accounting system for tracking renewable energy output in wholesale markets from facilities located in the Western Electricity Coordinating Council Region (WECC). An RFP for the software has been issued and the system is expected to be operational early in 2007. WREGIS has been designed initially to meet the compliance needs of State RPS programs as well as voluntary renewable energy markets as an accounting tool. The system also establishes the property rights to the non-energy attributes (represented by a renewable energy certificate) associated with the generation of each MWh of renewable power. It is possible to add an algorithm that would convert

[102] / A voluntary affiliation of issuing bodies that will be addressing issues of double counting, among other things.

an MWh of renewable energy generation into pounds of carbon avoided (based upon the type of facility, its location, date the project became operational, and the methodology adopted by the State for calculating GHG emission benefits). In this way, WREGIS could also be used to estimate the GHG savings associated with renewable energy production as well as identifying who has possession of those carbon reduction attributes.

Moreover, WREGIS is designed to avoid double counting of renewable attributes by: (1) Issuing renewable certificates with a unique serial number for each MWh generated; (2) only allowing a certificate to be claimed by one account holder (e.g. a certificate may only be in one account or sub-account) at any specific time; and (3) only issuing certificates to and tracking certificates that are whole (i.e. have retained all of the environmental benefits they were 'born with' such as carbon). WREGIS will also allow a GHG reduction program to estimate savings that result from the State's RPS program and identify GHG benefits that might accrue from renewable energy purchases in voluntary markets, additional to the RPS program.

Finally, though it would cost money, WREGIS could be adopted to include liquid fuels from renewable sources and could be expanded to track all generating resources. WREGIS will certainly be an important and flexible accountability tool for California and other state's GHG reduction programs.

California Climate Action Registry (CCAR)

The California Climate Action Registry is a non-profit public/private partnership that serves as a voluntary greenhouse gas registry to protect, encourage, and promote early actions to reduce GHG emissions. CCAR is another important tool for the state to use in meeting its GHG reduction goals and it too could be expanded to serve the western states. It is complementary to WREGIS and will also serve a key role in carbon reduction accounting ensuring that reductions are attributed to the appropriate entities, particularly for voluntary market participants. It is important that CCAR, WREGIS and California's GHG reduction programs are synchronized to ensure there is no double counting while giving fair credit for GHG reduction investments made in the public or private sectors through mandates or voluntary actions.

A related issue is for CCAR to develop acceptable protocols for fuel-based renewables (primarily Biofuels) to ensure that the carbon reduction benefits from fuel conversion are credited to these projects as well as those benefits associated with displacing conventional electricity from California's electricity grid.

What if there is no 33% RPS but only a 33% RE target?

Only one of the strategies discussed earlier in this chapter is dependent upon a mandatory 33 percent RPS target. It is undoubtedly more efficient and faster to reach a 33 percent renewable energy target through the use of a state mandate (i.e. a renewable portfolio standard), but it could, with difficulty, be accomplished in other ways. For now the major barrier to reaching higher levels of renewable energy supply is language included in SB 1078 that disallows the CPUC from establishing renewable energy *requirements* that exceed 20 percent.

Recommendations

Combine Integration Strategies

The CPUC should consider implementing a combination of strategies to incorporate renewables into a GHG reduction process:

a. Implement a 33 percent renewables portfolio as either an RPS mandate or a planning target.
b. Implement an integrated resource planning approach (that incorporates the RPS or renewables target as well as the Commission's Loading Order rules, carbon adder for emitting resources, and a greenhouse gas performance standard as a transition strategy while a GHG Cap and Trade program is being considered.
c. Ensure through legislation that customer owned as well as IOU, LSE and CCA electricity servers meet the same GHG reduction requirements and timelines.

WREGIS Participation

Require that all renewable energy participation in RPS and GHG reduction programs is contingent on participating in the WREGIS tracking system.[103]

WREGIS Emission Data

Support changes to WREGIS that include calculation and tracking of carbon reduction benefits from renewables (including liquid fuels).

Ensure Out-of-State RECs have Environmental Benefits

Through WREGIS protocols and work with NAAIB and the Western Governor's Association, make sure California can take credit for the GHG reduction benefits associated with the purchase of out-of-state renewables and RECs for either compliance or voluntary programs and that no double counting occurs.

Integration of CCAR, WREGIS and GHG Programs

Ensure CCAR, WREGIS, and the state GHG reduction programs are integrated in a manner that avoids double counting and handles GHG reduction credits consistently for both public and private sector investors.

[103] / The CEC could require RPS progress reports from municipal utilities to include WREGIS account records.

WORKPLAN AND SCHEDULE FOR ACHIEVING 33 % RENEWABLE GOALS

This section summarizes the recommendations developed in this report directly associated with CPUC jurisdictional activities into a preliminary workplan of actions that would improve the likelihood of achieving a 33 percent renewable energy future for California.

CPUC Workplan for Critical Actions

Developing a workplan for meeting a 33 percent renewables target is dependent first upon California's utilities meeting the current 20 percent RPS target. Based upon conversations with CPUC Commissioners and staff, a number of changes are already planned to improve and streamline the 20 percent RPS process. However, there are three critical actions that we believe should be taken right away that are important for meeting the 20 percent as well as a 33 percent RPS.

1. Clarify penalties for non-compliance. We would like to reinforce the need for the CPUC to clarify the specific conditions under which penalties would or would not be applied in order to help eliminate any uncertainty and misperceptions that presently exist We see evidence of differences in perception between the CPUC and some stakeholders about the likely willingness of the CPUC to actually apply such penalties that undermines credibility and efficient actions by participants. We believe it is very important that the utilities and stakeholders believe the CPUC is serious about meeting the 20 percent RPS compliance deadline in 2010. Given that the highest forecasts of natural gas prices are for the 2005 to 2013 timeframe,[104] delay in the implementation of the 20 percent RPS could result in ratepayers paying billions of dollars in unnecessary costs associated with the operation of fossil plants necessary to replace the energy that would otherwise come from renewable facilities. For this reason alone it is imperative that the CPUC do everything possible to meet the 20 percent RPS as soon as possible.

2. Address potential contract failure. We strongly encourage the CPUC to anticipate and address this risk now, instead of addressing it after the fact by either imposing burdensome noncompliance penalties on utilities or essentially granting the utilities a "free-ride" and forgiving their lack of compliance. Addressing the issue in the near term will ensure that the state's utilities do not

[104] / In the new CPUC gas forecast used for the MPR.

fall behind in achieving their renewable energy purchase requirements, an especially important goal if the procurement target is raised to 33 percent.

3. <u>Open discussions with the FERC.</u> Resolving the problems of expanding California's transmission grid in a manner that facilitates new renewables mandated by RPS legislation and CPUC policies must be a priority if the 20 percent RPS is to be met let alone a 33 percent target. Though the FERC turned down the SCE Trunk Line proposal, there may be other options for achieving the desired results that are acceptable to the FERC but have not yet been explored. We believe opening a dialogue as soon as possible between the FERC and the CPUC, ISO and possibly the Governor's Office could lead to an important breakthrough in resolving this important transmission problem.

In addition to the actions listed above that are critical to meeting the 20 percent RPS, we have listed eleven of the most important CPUC actions that should be undertaken in the short-term to lay the groundwork for a 33 percent renewables target:

1. Incorporate a 33 percent renewable energy target into the IOU planning and procurement process (*as soon as practical*).
2. Integrate renewable RPS planning and procurement into the resource planning process (*within the next planning cycle*).
3. Begin the process of reconfiguring the CA supply system for greater flexibility by recognizing the value of load-following fossil plants in the resource acquisition process (*within the next planning cycle*).
4. Make explicit critical path RPS issues and set a priority schedule for issuing the requisite decisions (*as soon as possible*).
5. Improve transparency in the RPS procurement process (*over the next six to nine months*).
6. Speed and streamline the solicitation process (*over the next one to two years*).
7. With the ISO, secure treatment of transmission upgrades in advance of generation requests (*begin immediately – timeline may be 2 to 3 years)*.
8. With ISO, expand justifications for new transmission to include state mandates (*implement as soon as possible).*
9. Work with the Western states on wind integration issues (*implement as soon as possible)*.
10. Consider requiring over contracting of renewable resources (*over the next year).*
11. Allow shaped or firmed renewable energy products (*as soon as practical*).

The following table divides the list of the recommended tasks according to the on-going proceedings into which they might fit. It also identifies those actions that require a significant lead time thereby suggesting that the Commission might want to begin working on them soon. Finally, the table indicates actions that may require legislation before they can be undertaken by the CPUC, or actions that though important, might be left to a later date for implementation.

Table VII-1 -- CPUC Schedule of Actions for Achieving 33 % Renewables

CPUC ACTIONS:	On Going Actions or Ones with Long Lead-Time	May Require Legislative Action	May be left to Later Time
Resource Planning & Procurement Process Incorporate a 33 % RE target into planning & acquisition process			
Integrate RE planning & procurement into IRP	X		
Use common data sets (CEC data sources where possible)	X		
Reconfigure CA electric system for greater flexibility by recognizing the value of load-following fossil plants	X		
RPS Implementation Process Prioritize critical path decisions			
Improve transparency[105]		X	
Speed & streamline solicitation process	X		
Require all RE in RPS or CO2 reduction programs to participate in WREGIS			
Consider over contracting for RE			
Allow unbundled RECs for out-of-state RE	X	X	
Institute new contracting options			X
Clarify system of penalties & revise some flexibility mechanisms			X
Consider utility incentive program			X
Consider central procurement agent		X	
Consider including aggregated DG as a priority set-aside in one or more RPS solicitations			
Transmission OII			
With ISO, secure treatment of transmission upgrades in advance of gen. requests	X		
With ISO, expand justifications for new trans. to include state mandates.	X		
Design/establish transmission corridors	X		

[105] We believe some improvements can be made even under present legislation though a legislative change is desirable in the longer term.

With ISO, incorporate RE into trans. planning	X		
With ISO, institute locational incentives	X		
With CEC, form new trans. stakeholder groups			
Support Western trans. planning forum			
Establish mechanism for timely recovery of trans. costs	X		
Institute incentive for the use of new transmission technologies	X		
Ensure RE can participate in capacity markets	X		
Work with Western States on Wind Integration	X		
Eliminate MPR/SEP	X	X	X
DG Proceedings Maintain support for DG including net metering	X	?	
Consider PV Tariff	X		
Clarify DG/REC rules			
Encourage State IOUs to offer Green Pricing			
Greenhouse Gas Reduction Program			
Continue deliberations on GHG Cap & Trade program	X	?	
Ensure RE is able to receive CO2 benefits under C&T programs			
Support changes to WREGIS to include CO2 reduction values	X		
Support coordination between WREGIS/CCAR			
Ensure Out-of-state Renewables/RECs include CO2 benefits			

Discussion of Key Actions

<u>Integrate RPS Procurement into a Comprehensive Utility Resource Planning and Procurement Framework</u>

With natural gas prices reaching new highs, and with a re-invigorated concern about global climate change, attractive opportunities for renewable energy may be overlooked if they are not carefully evaluated within a holistic, integrated resource planning and procurement framework. Such a framework can be defined by least-cost, best-fit analysis, **but such analysis may need to take into consideration a broader array of social objectives than those currently incorporated in utility analysis procedures**. At a minimum, such a framework must be able to balance the expected cost and risk of different resource options, fairly compare fixed-price renewables to variable-priced fossil resources, and address the risk of future regulatory changes, including the possibility of carbon regulation. In addition to improve system flexibility, it would be beneficial if the analysis considered non-renewable facilities that have features that accommodate the integration of intermittent renewables.

Prioritize Critical Path Decisions and Improve Transparency

We understand the CPUC is constantly working to improve their regulatory processes, but it is particularly important for meeting a 33 percent renewables target that the PUC is perceived as maintaining a consistent RPS focus, and that critical path decisions are handled in an expeditious and timely manner. Increased transparency of the procurement process will increase credibility and stakeholder support. Information that might be released under current regulation includes the number of projects bid into each RFO and the proportion that fall under each technology category.

Speed and Streamline the Solicitation Cycles

Even at the 20 percent RPS level, some streamlining of the utility acquisition cycle is necessary. The more smoothly the 20 percent procurement cycles are handled, the more enthusiasm and robust the 33 percent procurement cycles are likely to be. However, further changes may be required to meet a 33 percent target. If so, the CPUC might want to consider less frequent but larger RFO, and establishing deadlines by which utilities must submit contracts under each RFO. The Commission should also further standardize procurement practices and contract terms and conditions to minimize the time consuming process of negotiating with short-listed bidders.

Consider Requiring Over Contracting

Though the CPUC has allowed utilities to bank projects acquired in advance of annual need as a flexibility mechanism that is not the same thing as over contracting. Banking still assumes that all projects will eventually become operational. Over contracting assumes some portion of the contracted projects will fail to become operational. In the near term, we recommend that the CPUC encourage over-contracting by clarifying the application of penalties and flexibility mechanisms in the event of contract failure. In the longer term the CPUC may require over contracting depending upon actual procurement experience. Addressing the issue of contract failure in the near term will ensure that the state's utilities do not fall behind in achieving their renewable energy purchase requirements, an especially important goal if the procurement target is raised to 33 percent. For those electricity suppliers that are already near the 20 percent target, the development of a 33 percent planning goal along with the encouragement of over contracting would provide an incentive for continued aggressive renewable energy purchases in the near to medium term before a 33 percent RPS legislation is enacted.

Provide Deliverability Flexibility and Allow Unbundled RECs for Out-of-State Renewables

California's renewable energy delivery requirements were recently modified to allow for a broader range of delivery locations. However, to meet 33 percent renewable penetration, additional measures would be beneficial. RECs have several benefits that add flexibility to policy implementation and may decrease costs. RECs allow more flexibility in transmission expansion implementation. Allowing unbundled RECs to participate in RPS procurements may also put competitive downward pressure on bundled renewable energy costs. Though unbundled RECs are not a panacea to the very real transmission constraints that currently exist, use of unbundled RECs can help facilitate RPS compliance for the state's ESPs and CCAs and for those utilities with constrained transmission ties with the rest of the state. With an aggressive 33 percent target, we believe that it may ultimately be necessary to provide this additional delivery flexibility to out-of-state generators.

In our analysis we looked at the question of whether it would be beneficial from a rate perspective to cancel or defer some transmission upgrades designed to deliver renewables from outside the state into the state, or some upgrades that are at higher risk of non-approval in favor of replacing that power with RECs.

A case that exemplifies such a scenario is the delay of two investments intended to increase capacity for delivery of out-of-state renewables (the 2013 PDCI Line Tap near Gerlach and the 500 kV Captain Jack-Olinda Tracy improvement), as well as the final phase of the Tehachapi transmission expansion in 2020. Together, these investments total $1.74 billion. The impact of delaying these investments would be to reduce energy deliveries available to the RPS by a total of 10 million MWh. The delay of these investments would not result in energy shortages within the state, and RECs could offer a way for utilities to meet their RPS obligations until the transmission was completed at a later time. The effect of not completing these transmission projects would be to reduce the 2011-2020 NPV costs of the RPS by $191 million, and the NPV costs for the 2011-2030 timeframe would be reduced by $757 million from the *33 Percent Renewables Base*

If these investments were delayed, one option to consider would be the procurement of RECs and non-renewable energy to replace the 7.7 million MWh of renewable energy impacted by these transmission delays. Purchasing RECs and nonrenewable electricity to replace the renewable energy that would have been delivered to the RPS with these transmission investments is not likely to result in cost savings because the average cost of bundled renewable energy purchased for the RPS is projected to be lower than the nonrenewable market price during this time frame.[106] Nevertheless, RECs do provide a mechanism that would allow the IOUs to continue to comply with their RPS obligations if needed transmission upgrades were delayed.

[106] However, exceptions to this example could occur that could result in ratepayer savings such as a situation where RECs are combined with energy from a hydro plant, or where the transmission delays were earlier in the cycle when renewables are more expensive than the non-renewable energy market price.

One of benefits of bundled renewable energy purchases is their hedge value against rising natural gas prices. In a REC procurement, this hedge value could be preserved through the use of contracts for differences tied to natural gas prices.

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

We further recommend that the CPUC specifically allow renewable developers to offer shaped or firmed products, as long as renewable electricity is delivered *into the state*.

The Importance of Long-term Contracting and Contracts for Differences

Though we know that long-term contracts are important for financing renewable generating facilities, they also provide benefits to ratepayers. Long-term contracts can be used to reduce differential rate impacts across years. As shown in the *33 Percent Renewables Base Case* scenario in Section IV, small rate increases are expected in the first years of meeting the 33% target, but in the later years the RPS procurements result in net rate savings. Twenty year contracts (rather than ten year contracts that must be renegotiated) would better allocate those benefits. Some portion of longer-term renewable energy contracts (15 to 20 years) can serve as a hedge against increased bid prices after the first 10 years and ensure delivery of the longer-term benefits from these facilities.[107]

Uncertainty about future supply costs can be dealt with through various contracting mechanisms. For example, mechanisms such as contracts for differences, for either energy or REC purchases, can provide a cap on the so-called “above market” costs associated with some RPS procurements. Such mechanisms may be especially useful in the years where renewable energy costs are more likely to be above market prices, and they can be used as mechanisms to levelize the costs and benefits of procurements over the procurement life time.

Flexible Rate Making Mechanisms

Any negative incremental rate payer impacts of the RPS decline over the 20 year analysis horizon. And, as demonstrated in the base case, there can be inconsistent changes in rate impacts from year to year. To promote rate stability, the CPUC should consider rate making mechanisms (e.g. balancing account) that smooth the impact of RPS procurement costs on rates by spreading the costs/benefits over the life of the projects, rather than reflecting incremental RPS costs in rates on a year by year basis.

---

[107] / Though shorter term contracts (10 years) provide a hedge against a situation where conventional supply alternatives costs drop significantly, a mixture of contract lengths (10, 15, and 20 years) can hedge against both that situation and a situation where alternative suppliers have relatively high costs and renewable generators are tempted to price their bids accordingly. The second ten year period is when consumers will see the greatest benefits from RPS procurement barring a collapse of the fossil fuel market.

Consider New or Revised Utility Incentives Mechanisms

Meeting a 33 percent target requires willing buyers. Under the present regulatory structure, the state's utilities may profit from owning renewable energy assets (through a return on rate-based facilities), but purchases of renewable electricity from third parties will generally provide no such opportunity. We recommend that the CPUC *consider* developing a more effective system of incentives that provides the IOUs some profit for cost-effective achievement of the 33 percent goal or for achieving the goal in advance of the compliance timeline.

Central Procurement Agent

There have been discussions about the possibility of a "central procurement agent" that would purchase renewable energy on behalf of ESPs/CCAs or their customers,[108] and that would otherwise follow similar procurement processes as the state's IOUs might follow. Though we expect central procurement ideas to be vetted in regard to the 20 percent requirement, we also recommend that they be considered in the context of a 33 percent target.

Common Data Sets for Analysis

From the work on this report it has become clear that the California Energy Commission has excellent analytic skills and technical reports that provide an invaluable basis for evaluating the impacts of various electricity policies and programs. Though the Joint CPUC/CEC Renewables Committee has collaborated well on a number of policy issues, we still found instances where the two agencies could significantly improve their coordination. For example, the CEC develops an independent natural gas forecast for the IPER Report while the CPUC has developed its own natural gas forecast for use in the market price reference (MPR) proceedings. Though the CEC forecast focuses more on long-term natural gas prices and the CPUC forecast focuses on natural gas prices over the next five years, nonetheless, it should be possible to develop one forecast that serves both functions rather than duplicating efforts. Given the limited resources available to each agency, closer coordination seems advisable. We therefore recommend that the CEC serve as a common source for electricity and natural gas data required for decision making. The CPUC can take advantage of these analytic talents by applying these data to their analyses of regulatory issues rather than duplicating tasks resulting in conflicting or inconsistent data and decisions.

Infrastructure Modifications

Infrastructure modifications include three primary areas: (1) Transmission, (2) System Configuration, and (3) Western State Renewables Integration. The transmission recommendations are a subset of recommendations from the Transmission Section that are directly applicable to CPUC responsibilities. The system configuration

[108] / Or as a last resort for IOU compliance if they do not comply under present policies and processes.

recommendation resulted from the resource discussions in Section II and the Western State Renewables Integration recommendation are from the Resource and Transmission Section discussions.

Transmission

These transmission recommendations fall into three categories: (1) Increasing Transmission Capacity, (2) Greater Operational Flexibility, and (3) More Receptive Transmission Tariffs and Market Design. Though FERC and CAISO control much of the transmission decision making, nonetheless the CPUC and the CEC both play critical roles and can provide leadership and direction for the FERC and ISO decision makers. Moreover, the CPUC can provide alternative rate recovery options for transmission investments to the extent that FERC is unwilling or unable to facilitate the transmission additions needed to support renewable energy targets.

Increasing Transmission Capacity

> Secure rolled-in rate treatment for transmission built ahead of renewable generation plant interconnection requests
>
> In conjunction with the California ISO, the CPUC (and possibly the Governor's Office) can conduct informal discussions with the Federal Energy Regulatory Commission on their willingness to approve a Section 205 filing by the California ISO under the Federal Power Act. This filing would seek to recover the costs of transmission built ahead of renewable energy plant development in ratebase through a transmission grid access charge to load serving entities (paid for by all users of the California ISO grid.)[109]

If this action is not successful the CPUC could:

> Allow transmission lines that are not designated as "network resources" for inclusion in transmission ratebase to be placed in distribution ratebase. [110]

In addition, the CPUC could work with CAISO to:

> Encourage the CAISO to expand the justifications for identifying new transmission facilities for construction in the California ISO transmission planning process beyond economic or reliability reasons to include building transmission to achieve state policy directives.
>
> Establish designated transmission corridors.

[109] / Though the SCE trunk line application was rejected, there may be variations on this concept that could be supported by the FERC.
[110] / PU Code section 399.25.

Examine the right-of-way needs for future transmission projects, designate and conduct environmental reviews for important corridors, and allow the banking of necessary lands for right-of-way ahead of need. For prospective acquisition and banking of land for corridors, establish a mechanism for transmission owners to recover costs on a timely basis.

<u>Coordinate with the CAISO to ensure transmission planning for renewable resources is part of the long-term transmission planning process.</u>

Clear roles and responsibilities for transmission planning to achieve the RPS could speed attainment of renewable energy objectives. Clarify that transmission projects may be planned and constructed in support of state renewable energy policy in addition to traditional reliability or economic planning criteria.

<u>Coordinate with the CEC to form new stakeholder study groups for transmission projects for renewable resources in renewable energy cluster areas.</u>

Study groups have been formed for the Tehachapi and the Imperial Valley areas. Applying best practices from these two groups to other areas is a good model for gaining the consensus of multiple affected parties and establishing a viable plan for transmission development.

<u>Coordinate with the CAISO to study the establishment of locational incentives for generators.</u>

If generators locate on the correct side of congested transmission lines, they can displace the need for "imported" energy into the congested area and thereby free up capacity on the congested transmission line for other uses. Post implementation of the California ISO Market Re-design and Technology Upgrade (MRTU) project, locational incentives are created by locational marginal pricing (LMP). However, experience in PJM suggests that LMP alone may not be effective in getting generators to locate in high congestion cost areas. For example, PJM has evaluated locational incentives after years of operating an LMP market. The incentives could be offered to both thermal and renewable generators. Research conducted by the California Energy Commission on strategic siting of renewables suggests strong locational benefits for renewable energy plants.

<u>Support the development of a proactive, permanent Western Regional Transmission Planning Forum that could address regional renewable energy issues.</u>

<u>Reduce transmission development risks by ensuring timely recovery of all prudent transmission development costs for renewable transmission projects.</u>

Allow timely cost recovery in retail rates or other means of compensation for all transmission development costs for renewable resources. This would reduce development risks and encourage pursuit of transmission solutions to congestion problems.

<u>Support the development and rapid implementation of transmission investment incentives as envisioned in the Energy Policy Act of 2005.</u>

<u>Recognize the value of load-following capability of fossil plants to renewable energy in integrated resource planning and regulatory cost recovery proceedings.</u>

Load following capability is often associated with higher heat rates and lower fuel efficiency for thermal generators. Individually, these resources may not look as cost competitive. However, in combination with renewable resources they can help to achieve a lower system cost, improved reliability and greater operational flexibility.

<u>Provide transmission owners incentives to adopt new transmission technologies that increase operational flexibility for renewable resources.</u>

Through favorable regulatory treatment, the California Public Utilities Commission can encourage investigation and adoption of new transmission and energy storage technologies that will increase the operational flexibility and efficient utilization of the grid for renewable resources. Examples of favorable regulatory treatment include accelerated depreciation or an enhanced return on equity, either fixed or performance-based.

<u>Develop capacity values for renewable generators and ensure that a future capacity market allows renewable generators to participate.</u>

Create a methodology for calculating capacity value. Calculating renewable energy capacity values based upon probability of operating at time of peak or upon average historical operating data are both used in other regions. Geographic or spatial diversity of wind generator locations contributes to offsetting wind generator variability, since varying wind patterns tend to cancel each other out. This can improve capacity values and suggests that transmission requirements will not increase linearly with growth in wind generation capacity.

System Configuration

During the past two decades, as natural gas prices remained low and stable, gas-turbine combined cycle power plants became the power plant option of choice for base load needs. With the latest jet engine technology applied, the combined cycles were designed to be clean and very efficient. With base load operation in mind, and a goal to have the very highest conversion efficiency possible, these plants were designed for long, continuous operation at full load. Thousands of MWs of such capacity was built to serve

California’s growing electric load and to replace older steam-cycle based fossil generation throughout the 1990s.

Over the past two years, natural gas prices have risen dramatically. As a result, combined cycles provide more of an intermediate duty service. Ideally, the power plants would operate at part load for many hours in a day, and be shut down completely at night when loads drop off. Fundamentally, gas turbine based power systems are capable of such duty. But the fleet of combined cycles built in 1990s was not designed for such service. They have poor part load heat rates and relatively long start up periods.

California’s loads will continue to grow, at the same time we may also retire much of the remaining fleet of old, inefficient gas generation left over from the 1970s. Even with a large increase of renewable power plants to serve an expanded RPS, new gas-fired generation will be needed. As these new plants are conceived and deployed, it will be important to design them with the kind of operational flexibility that would make them highly complimentary with the potentially large fleet of wind and solar plants we could deploy over the next 15 years. Gas turbine-based power systems with good part load efficiency, fast ramp rates, rapid startup cycles, and located as close to load centers as feasible, would allow the complex California electric grid to accommodate larger amounts of intermittent renewables as well as improve the flexibility of the entire system.

Utility and grid planners should be encouraged to specify new fossil energy needs that generally have the features described above.

Western State Integration

The vast wind resource present in California, Oregon and Washington, and the current interest in expanding wind deployment in those states by up to a factor of 5, has compelled many to examine the wind-hydro integration opportunity in more depth. Bonneville Power Administration has already developed a Storage and Shaping Service for wind, using its hydro assets on the Columbia River to provide this. This service is available to California Utilities, and several have availed themselves of it however we believe much more can be done in this area.

The CPUC should strongly encourage California, Oregon and Washington, including the utilities and control area operators, to examine the benefits of a regional approach to wind-hydro integration. Through the operation of the Pacific AC and DC Interties, there has been a long history of California and Pacific Northwest cooperation on a mutually beneficial basis to exchange large quantities of energy and capacity to serve radically different load profiles. The existing hydro and interconnecting transmission assets across the west can be further exploited to increase the quantity of low cost intermittent wind that can be accommodated on the western grid.

Supplemental Energy Program (SEP)

Though it would clearly require legislative action, one of our most important recommendations is to eliminate the present MPR-SEP structure of the California RPS as the state seeks to achieve a more aggressive 33 percent target. The existence of SEPs makes the California RPS unique, but less recognized is that SEPs create perverse incentives. Because utility payments are capped at the MPR, utilities may be indifferent to the cost of contracts that exceed the MPR. Regulatory approval of renewable energy solicitations and evaluation protocols, PRG oversight, and CPUC contract pre-approval can counteract these perverse SEP incentives, but each result in added regulatory complexities and burdens. This added complexity may in turn slow the state's progress towards its aggressive renewable energy goals and result in piece meal electricity planning that can undermine the ability to design a flexible, fully integrated electricity system.

Eliminating the MPR – SEP structure, and simply allowing utilities to recover prudent renewable energy costs in retail rates (like most other states' RPS policies), would not absolve the CPUC of its policy and procurement oversight responsibilities, but it would make those responsibilities easier to manage. Eliminating the MPR-SEP structure would also help alleviate some of the other concerns with that structure, discussed in Section V. The primary stated advantage of the current MPR-SEP structure – the establishment of a cap on overall program costs – can easily be accommodated through other means including traditional rate regulation, and integrated resource planning and procurement policies. Given the relatively low short-term negative rate impact forecast in this analysis and the positive long-term benefits for the State, it seems the risk of major rate increases due to renewable energy costs might be managed through traditional regulatory means.

To avoid interruption of a program that is beginning to show signs of working, if the state's policymakers do decide to develop a new structure for the state's RPS without MPR and SEPs, we recommend that the present system remain in place until the new system is fully operational.

Distributed Generation

According to PV experts, the expectation is for PV to be *cost competitive with retail electricity rates* within ten to twelve years. Whether this comes from incremental improvements in the technology, manufacturing and installation scale-up or due to a major technology breakthrough, it is generally agreed that a significant reduction in PV costs will occur during the timeframe we are discussing in this paper. Estimates for the amount of PV capacity that might be installed in California between 2010 and 2020 are at the low end 3,000 to 6,000 MW, and could be as high as 10,000 to 15,000 MW. But such large amounts of DG will not be realized unless actions are taken to develop the necessary infrastructure.

Maintain Stable DG Support

Without other legislation, responsibility for maintaining consistent momentum for the DG sector falls to the CPUC.[111] Over the next five years, develop and maintain stable state support for DG/PV (e.g. help keep PV growth at ~30 percent) in order to maximize the amount of cost-effective PV available in the 2010 to 2020 time period.

Maintain Net Metering

Support and maintain the existing net-metering program to support a stable market environment. Adjust the program and the use of a program cap as appropriate to changing circumstances

Implement PV Tariff

Develop a state-wide PV tariff (analogous to the PG&E A-6 tariff) that is based on the value of the time of delivery) that can supplement or replace the present tariff structure when the timing is right. There could also be a regulatory reward side for IOUs that develop innovative programs and take advantage of DG/PV to reduce system costs of grid operation while stimulating greater use of PV.

Inter-agency Working Group

The CPUC should consider including the PV industry in the inter-agency working group for self-generation. Members of the DG community feel they could better support the implementation of activities and improve efficiency of PV programs if they were involved earlier in the decision-making process and able to provide insights into what is feasible in the marketplace.

Clear Rules for DG Customers

Clarify the rules to ensure the owners of distributed generation facilities have control of the RECs produced by those facilities unless they explicitly choose to deed those REC benefits to another party in exchange for a government incentive, or some other type of financial or contractual benefit. This will allow, customers with distributed generation systems in the future to make informed choices regarding the disposition of the renewable energy certificates (REC) from their systems under various incentive scenarios.

[111] / On October 27, 2005, Governor Schwarzenegger announced his intention to "aggressively pursue" his Million Solar Roofs Initiative with the CPUC, overcoming the obstacles presented by the Legislature and its special interest issues at the end of this year's session.

Aggregated DG RPS Priority or Alternative DG/RPS Target

Allow aggregated power from distributed generation to participate in utility RPS solicitations and in the future establish a separate DG/RPS target beyond the 33 percent renewables goal.

Voluntary Renewable Energy Market

The voluntary market in California could substantially supplement GHG reductions that occur as a result of mandatory programs (see Section VI for details). It is possible that if California's electric utilities offered well designed Green Pricing programs this could add 1 to 3 percent additional renewable sales above the State RPS mandate. We believe it is possible for California to achieve 3 to 5 percent of its electricity supply from distributed renewable generation (primarily from PV installations) during the 2010 to 2020 timeframe. It is possible that if California's investor owned electric utilities offered well designed Green Pricing programs or Green Tariffs this could add 1 to 3 percent additional renewable sales above the State RPS mandate.

Contrary to arguments heard in some quarters that green pricing programs could drive up the cost of complying with the RPS, we believe increased renewable energy market growth can, under some circumstances, actually reduce costs. Though transmission issues may continue to be a problem in the near future, a utility could purchase a few MW of additional capacity to use for their Green Pricing program from winning bidders in their RPS solicitation. Moreover, utility green pricing programs are not hampered by the same rules and restrictions as RPS and are free to purchase RECs and rebundle them with other energy supplies and other types of market options.

In order to achieve these results, the CPUC needs to do the following:

Carbon Benefits for Renewable Generators

Support voluntary renewable energy markets by ensuring renewable energy generators are able to pass along the carbon benefits associated with their power generation to their customers. This includes ensuring renewable energy and RECs from projects located in other states but sold into the California market are able to transfer their carbon benefits to the California purchaser.

Additionality of Voluntary Market

Ensure renewable energy sold in voluntary renewable energy markets is accounted for separately and not counted toward compliance with mandatory carbon or RPS targets.

Green Pricing

Encourage or require State IOUs to offer green pricing programs that incorporate best practices:[112]

m. Are based on new renewable generation facilities
n. Are additional to utility mandates
o. Allow customers to hedge against fuel price fluctuations
p. Allow the use of regional RECs as appropriate
q. Encourage the use of contracts for differences for RECs
r. Keep any above market prices consistent with actual renewable energy costs and only include reasonable fees for services

Greenhouse Gas Reduction Program

Meshing the 33 percent renewable energy target with electricity sector greenhouse gas reduction targets can be accomplished in several ways: (1) Codify the 33 percent RPS target and move to fully implement the mandate; (2) integrate the greenhouse gas reduction target, as well as the renewable energy and energy efficiency goals into the utility resource planning and solicitation process and implement as an integrated approach; (3) translate the greenhouse reduction goals into an electricity sector cap and trade program; or (4) some combination of the above. The following are the CPUC tasks we believe are required to fully integrate renewables into the GHG reduction program:

Combine Integration Strategies

The CPUC should consider implementing a combination of strategies to incorporate renewables into a GHG reduction process:

d. Implement a 33 percent renewables portfolio as either an RPS mandate or a planning target.
e. Implement an integrated resource planning approach (that incorporates the RPS or renewables target as well as the Commission's Loading Order rules, carbon adder for emitting resources, and a greenhouse gas performance standard as a transition strategy while a GHG Cap and Trade program is being considered).
f. Ensure through legislation that customer owned as well as IOU, LSE and CCA electricity servers meet the same GHG reduction requirements and timelines.
g. If a GHG Cap & Trade program is implemented, allocate emission allowances or credits to renewable generation including distributed generation. It is critical that the connection between renewables and carbon emission reductions be made explicit in order to encourage the level of renewables necessary to meet the desired GHG targets.

---

[112] / From *The Regulator's Handbook on Renewable Energy Tariffs*, Best Practices for Green Pricing Programs,. Center for Resource Solutions, November 2005.

WREGIS Participation

Require that all renewable energy participation in GHG reduction programs is contingent on participating in the WREGIS tracking system to increase credibility, avoid double counting, and simplify compliance.

WREGIS Emission Data

Support changes to WREGIS that include calculation and tracking of carbon reduction benefits from renewables (including liquid fuels) to expand the tools available to measure and validate greenhouse gas reduction claims.

Ensure Out-of-State Renewables/RECs have Environmental Benefits

Through WREGIS protocols and work with NAAIB and the Western Governor's Association, make sure California can take credit for the GHG reduction benefits associated with the purchase of out-of-state renewables and RECs for either compliance or voluntary programs and that no double counting occurs.

RECOMMENDATIONS FOR FURTHER STUDY

There are some elements identified in this report that would greatly benefit from further study to better understand the issue in greater depth and interactions among variables that can strongly affect the outcome. Many of these topics might be appropriate for investigation by the California Energy Commission under its PIER Program or through other means by either the CPUC or the CEC. The following describes key topics the authors feel should be studied further.

Resource Supply

Investigate the interaction of mechanisms (and their costs) to adjust for wind intermittency, capacity factor and resource adequacy.

We suggest the California Energy Commission's PIER Project examine further the inter-relationship of these three integration issues. Though a lot of research has already occurred both domestically and internationally assessing various wind integration costs (intermittency, capacity value, and resource adequacy), we have not been able to find any research that looks at how the costs associated with these three effects should be combined. Most wind experts agree that the effects are not strictly additive and that activities undertaken to address one factor may reduce or increase the others (e.g. measures taken to deal with intermittency may also affect the capacity value). No one to our knowledge has taken this next step to better understand the combined effects of various options.

Transmission And Operational Flexibility

Investigate opportunities to better utilize California's hydropower, pumped storage, and demand side management potential to address intermittency issues.

Include resources controlled by participating generators in the ISO, publicly-owned utilities, and state water management facilities (See Appendix III-A of the Transmission Section). California's peak wind generation occurs at night during off-peak loads. If wind generation at night could be used for pumped storage facilities, it would be transformed into dispatchable peaking capability.

Investigate opportunities to increase the utilization of the existing transmission infrastructure.

Investigate methods to better manage unused non-firm capacity on existing transmission paths (e.g. Path 15, Path 26, COB, and COI) for increased in-state renewable generation and out-of-state renewable energy imports. The implementation of the new LMP market design by the California ISO may contribute to improved utilization of transmission assets. However, reliability and other issues unrelated to market design also affect utilization of key transmission paths. Further, not all transmission assets important to California are under ISO control. The study would look at all transmission assets in the state, encompassing California's public and investor-owned transmission systems and transmission paths important for importing renewable energy, irrespective of grid ownership.

Distributed Generation And Voluntary Markets

The following research might be undertaken or requested by the CPUC to help inform future policy decisions related to distributed generation and other voluntary market issues.

Transmission and Distribution Costs Associated with Net Metering.

Further research is needed to better understand what, if any, T/D costs are being transferred from net metered customers to non-participating customers.[113] Any cost reallocation occurring today could be mitigated or reversed either through a T&D fee or by changing the method by which T&D costs are being recovered. Such mechanisms might be different for residential customers than for commercial/industrial customers

Renewables And Greenhouse Gas Reduction Programs

Investigate the Feasibility of Incorporating GHG Emission Values into WREGIS

The California Energy Commission should investigate the feasibility of incorporating GHG and other emission data related to renewable generation into WREGIS protocols. In addition, the Commission might also investigate the feasibility of incorporating liquid fuels into WREGIS thus creating a financial tool that might be useful when combined with other policies to stimulate greater use of Biofuels for both power generation and transportation.

Investigate the Integration of CCAR with WREGIS

The California Energy Commission should support research into the mechanism(s) necessary to integrate WREGIS data with CCAR to ensure purchasers of renewable energy and RECs can receive appropriate credit in CCAR for reducing their GHG footprint.

[113] / An Oklahoma study resulted in an estimated cost of $0.00017/kWh for transmission handling.