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California Energy Commission
Docket Office, MS-4
Docket No. 09-IEP-1G
Docket No. 03-RPS-1078
1516 Ninth Street
Sacramento, CA 95814-5512
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Re: California Energy Commission (Energy Commission) Docket Nos. 09-IEP-1G & 03-RPS-1078: Written Comments of Southern California Edison Company (SCE) on Joint Integrated Energy Policy Report (IEPR) and Renewable Committee Workshop: Electricity System Implications of 33 Percent Renewable

To Whom It May Concern:

SCE is pleased to provide comments on the Energy Commission's June 28 Joint IEPR and Renewables Committee Workshop on the Electricity System Implications of 33% Renewables. Mark Minick, Manager of Resource Planning for SCE participated on the panel. The responses to the questions for the workshop panel are provided as an attachment. We offer the following comments for your consideration.

CPUC, Energy Commission, and Nexant Studies Reach Similar Key Conclusions

Despite the lack of a "single" renewables integration study, it is important to observe that the California Public Utilities Commission (CPUC) Energy Division (ED), the Energy Commission, and the Nexant analysis reached similar conclusions in several key areas including timing, cost increases greenhouse gas (GHG) implications, natural gas usage and trade-offs between competing policy objectives. Below is a summary of each.

Timing

- CPUC ED - CPUC ED analysis included three timelines, none of which showed achievement of 33% renewables by 2020. Under Timeline 1 (Historical experience without process reform), which assumed no external risks, 33% RPS was achieved in 2024. Under Timeline 2A (Current practice with process reform), which also assumed no external risks, 33% Renewables Portfolio Standard (RPS) was achieved in 2021. Under Timeline 2B (Current practice with process reform), which also assumed no external risks, 33% RPS was not achieved.Nexant – The Nexant study stated that the siting and permitting of new generation may delay achievement of RPS goals. Delays are more likely to occur with higher RPS targets, since this could require the construction of additional solar resources in environmentally sensitive desert regions.

Cost Increases

- CPUC ED – The CPUC ED 33% RPS study showed an increase in electricity cost to get to 33% RPS ranges from 4-14%, with 7% identified as the "reference" case[1].
- Nexant - Relative to estimated rates for implementing a 20% RPS standard in 2020, estimated the electricity rate impacts to be 6.5-7.6% increase for the 33% RPS case in 2020 (based in part on relatively conservative transmission addition assumptions). (Nexant executive summary, page 1). SCE estimated the rate increase to be in the order of 10 – 12 % when considering other factors not included in the Nexant study.

GHG Implications

- According to the "Climate Change Scoping Plan – Pursuant to Assembly Bill (AB 32), the implementation of 33% renewables by 2020 will reduce GHG emissions by 21.3 MMTCO2e[2]. It is expected that the implementation of 33% renewables will reduce GHGs, but in SCE's opinion it is not the most cost effective way to reduce GHG emissions in the state or nationally.

Comprehensive Analysis/Assumptions

- SCE supports the Energy Commission's and CPUC's holistic approach to determining the impacts of 33% RPS by including other state policy objectives in the analysis.
- Energy Commission – The Energy Commission's 33% RPS analysis incorporated other related policy objectives implemented or being considered by the state. Examples of the Energy Commission's incorporation include Once Through Cooling (OTC) generating facility retirements of 12,655 Megawatt (MW) with 7,558 MW of replacement generation, 4,500 MW of Combined Heat and Power (CHP) and 6,000 MW of Energy Efficiency (EE). This comprehensive look can provide insights that may not be apparent from the individual policy objectives, such as an increase in natural gas usage due to CHP additions and EE (less energy usage results in lower renewable energy production to meet a 33% RPS goal).
- CPUC ED – The CPUC ED analysis assumed OTC retirements of 6,617 MW (compared with Energy Commission which assumed 12,655-7,558=5,097 MW of retirements). Regarding CHP, the CPUC ED study assumed a total of 1,574 MW nameplate small CHP and 2,804 MW of large CHP (report at page 28 http://www.cpuc.ca.gov/NR/rdonlyres/1865C207-FEB5-43CF-99EB-A212B78467F6/0/33PercentRPSImplementationAnalysisInterimReport.pdf).
- Nexant – The Nexant analysis assumed approximately 9,500 MWs in OTC retirements in both cases with 2,250 MW of quick-start peaking/load following fossil fuel resources added in the 33% case to maintain grid reliability and integrate the renewables. (net retirements of approximately 7,250 MW)

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[1] See slide #13 on http://www.energy.ca.gov/2009_energypolicy/documents/2009-06-29_workshop/presentations/04a_California_Public_Utilities_Commission_33_percent_RPS_Implementation_Analysis.pdf.

2 Climate Change Scoping Plan – Pursuant to AB 32, December 2008, Table 9, p 46.

Competing Policy Objectives

- SCE agrees with the CPUC ED's conclusion that "If the state does not plan for interactions between [EE], fossil retirements, and a 33% RPS, then a 33% RPS by 2020 could result in a surplus of energy or capacity and excess consumer costs. This interplay highlights the need to analyze and plan for interactions among the state's various policy goals. An integrated approach is needed to ensure that policy goals result in a resource plan that effectively furthers the important, underlying policy objectives and produces an efficiently integrated electricity system at an acceptable cost."[3] SCE urges the California Independent System Operator (CAISO) to take a similar comprehensive approach in its 33% renewables integration study.

PG&E's Calculator Requires More Review and Calibration

During the Workshop, Antonio Alvarez, of Pacific Gas and Electric Company (PG&E), presented a summary of a "Renewable Integration Calculator" (Calculator) they have jointly developed with The Brattle Group to help understand the operational impacts of intermittent resources. The Calculator showed that the variability and uncertainty of intermittent resources increases the need for regulation, load following, day-ahead commitment of generation and ramping resources. While SCE recognizes the potential benefits of having a simple tool to estimate the integration impacts of renewable generation, SCE cautions against drawing conclusions from the examples included in PG&E's presentation.[4] The amount of load following, regulation and additional capacity needed to accommodate intermittent resources will be the focus of the CAISO's 33% RPS integration study, due to be completed by the end of this year. As indicated in response to Energy Commission's first question[5], PG&E is working with the CAISO, as part of its 33% RPS integration project, to calibrate its Calculator. After the calibration, PG&E will make the Calculator publicly available along with a description of the methodology and user manual. SCE urges the Energy Commission to wait until the CAISO's 33% renewables integration analysis is completed before coming to conclusions regarding the amount of regulation, load following or day-ahead commitment associated with 33% renewables.

The current analysis is just a start in properly planning for the implementation of 33% renewables. In the near future, SCE will be working with the CAISO on its 33% RPS integration study. Since this is the first attempt to study integration costs at this level of penetration of intermittent resources, additional follow up studies will most likely be needed to fully understand the costs and complexity of such integration of higher levels of renewable generation. In closing, SCE cautions that it is critical that any policies recommending an increase to renewables targets be flexible enough to account for the range of potential solutions.

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[3] page 30 at http://www.cpuc.ca.gov/NR/rdonlyres/1865C207-FEB5-43CF-99EB-212B78467F6/0/33PercentRPSImplementationAnalysisInterimReport.pdf

[4] For example, slide 8 - the Calculator showed that if 4,000 MW of additional wind generation was added in the Tehachapi area of SCE's transmission system, approximately 40 MW of incremental regulation and 80 MW of load following would be needed. This may or may not be a correct value because the calculator has not been calibrated.

[5] http://www.energy.ca.gov/2009_energypolicy/documents/2009-06-29_workshop/presentations/03b_Pacific_Gas_and_Electric_Handout.pdf),

SCE appreciates the opportunity to participate in the IEPR process. If you have any questions or need additional information about these written comments, please contact me at 916-441-2369.

Very truly yours,

/s/ Manuel Alvarez

Manuel Alvarez

Joint Integrated Energy Policy Report
and
Renewables Committee Workshop
on

Electricity System Implications of 33% Renewables

June 29th, 2009

Mark Minick
Manager, Market Strategy & Resource Planning
Southern California Edison

Electricity System Implications of 33% Renewables

When interpreting studies that identify the feasibility of implementing a 33% renewables target, policymakers must keep in mind that any decisions based on a study's conclusions will be implemented in a legislative and regulatory environment, facing huge questions around the issues of once-through cooling, other air quality limitations, and market opportunities for renewable resources. Under such conditions, it is critical that any policies recommending an increase to renewables targets be flexible enough to account for the range of potential solutions to each of these issues. Accordingly, a holistic view of these competing issues is required to develop solutions that maintain overall grid stability. With these principles in mind, SCE addresses the discussion questions in the context of the Nexant Study.

Discussion Questions

1. What is/was the purpose and principle research questions of the study?

   The Nexant Study's aim was to identify:

   - Integration needs for maintaining system operability under various renewable resource combinations,
   - The transmission needed to interconnect increased levels of renewable resources across the entire state, and
   - The feasibility of siting, licensing, and developing enough of the necessary transmission and generation to reach a 33% renewables target, in the time allotted.

2. Brief description of methodology/links to documentation

   The amount of renewable energy needed to meet the 20% and 33% renewables targets by 2020 is based on the CEC's November 2007 load forecast.[6] The study assumes that renewable procurement incremental to the current 20% target will be available primarily from wind and solar resources in approximately equal energy proportions.
   The capacity contributions of renewable resources at the time of the system peak were estimated and applied toward meeting a planning reserve margin of 18%. If needed, additional fossil generation was added to meet planning reserve margin requirements.

   The generation data (i.e., unit heat rates, minimum up and down times, etc.) and generation profiles (i.e., wind and solar) are based on an Investor-Owned Utility (IOU) - revised version of the Transmission Expansion Planning Policy Committee (TEPPC) database.[7],[8] This data was used by Plexos in its production simulation modeling. The

[6],CEC-200-2007-015-SF2 (CEC's 2018 load was extended to 2020 with an annual growth of approximately 1.13%)

[7] http://www.wecc.biz/modules.php?op=modload&name=Downloads&file=index&req=view download&cid=32

[8] PG&E, SDG&E and SCE all contributed to the revised version of the database

output from that model included operations violations, greenhouse gas (GHG) emissions, transmission constraints, and costs. If necessary, additional fossil generation was added to the model to resolve operational violations.

Plexos' simulation output was used to perform a simplified version of the traditional transmission planning analysis. Only a base case analysis and limited single contingency analysis were used to identify the incremental transmission needed to meet a 33% renewables target.

3. Key study drivers

The key drivers in the Nexant Study were:

- The renewables mix (the amount of baseload (biomass and geothermal) versus the amount of intermittent resources (solar and wind) making up the renewable portfolio),
- The characteristics of existing and future fossil generation,
- The amounts of in-state and out-of-state renewables needed to help meet renewables goals,
- The assumed operational flexibility of hydro generation, and
- The ability to use transmission tie lines to meet intrahour scheduling capabilities across the Western Electricity Coordinating Council (WECC).

4. Findings and conclusions

The Nexant Study concluded that:

- Potential overgeneration and dump energy (where the must-take generation net of exports exceeds the load) scenarios can arise during certain times of the year and these situations are heavily dependent on the renewables mix and total renewables targets,
- There is a significant need for quick start/fast ramping technologies (generation and non-generation) in order to meet the operational needs demanded by the use of increased levels of intermittent renewable resources, and
- The GHG emissions levels in 2020 in a 33% target case are reduced by 16.5% from the base 20% target at a cost of approximately $180/metric ton.

5. Uncertainties

There were a number of uncertainties identified in the Nexant Study. These include:

- The ability to site, license, and develop transmission and generation necessary to reach a 33% goal by 2020,
- The level of renewables to be procured from outside California and the use of renewable energy credits,
- Gas and other fuel prices,

- The timing and quantity of fossil generation retirement, particularly if due to once-through-cooling regulations,

- Resolution of various GHG-related issues currently pending within the regulatory arena, and

- The cost of carbon credits.

6. Lessons for implementing a higher level of renewable in California by 2020

   There were a number of lessons learned from the Nexant Study. These include:

   - There is a high risk of dump energy during high coincident output hours due to overgeneration from renewable resources that the electrical system cannot accommodate.

   - Current siting, licensing, and development processes will challenge attempts to achieve increased renewables levels by target dates.

   - WECC-wide operational coordination will be required to meet the intra-hour schedules of intermittent renewables.

7. Recommendations for further analysis

   Future studies should focus on:

   - The intra-hour operability needs (e.g.,spinning, load-following, and regulation) required by the integration of increased levels of intermittent renewable resources,

   - The improvement of forecasting tools, which forecast the availability of intermittent resources in the day ahead and the hour ahead markets,

   - The detailed transmission analysis to identify the transmission needed to meet the WECC/ North American Electric Reliability Council (NERC) transmission planning criteria, and

   - The reflection of the operating limitations of hydro and other resources, and analyzing the effects of increased stress due to the integration of intermittent generation on resources, such as increased maintenance or less reliable operation.

8. Input assumptions: matrix for comparing studies

   a. Load forecast used?

   - The Nexant Study used the CEC's November 2007 load forecast.[9]

     The load forecast for the rest of the WECC, outside California, was based on the load forecast used in the CEC's Scenario Analysis of California Electricity System study.[10]

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[9] CEC-200-2007-015-SF2 (CEC's 2018 load was extended to 2020 with an annual growth of approximately 1.13%)
[10] CEC-200-2007-010-SF

b. How was the "additional renewables" (amount required for 33 percent renewable energy by 2020) calculated for your study?

- The Nexant Study assumed that all of California's load-serving entities meet a 20% goal by 2020. The incremental energy required to meet the state-wide 33% target was calculated as the difference between the two. The incremental procurement target is approximately 41,000 GWh in 2020.

  For 2020, the prior year energy sales were assumed to be 314,000 GWh

    For a 20% renewables goal, the target is 62,800 GWh.

    For a 33% renewables goal, the target is 103,620 GWh

- The Nexant Study also assumed that approximately 12% of the renewable energy necessary is procured from outside of California and is assumed to be delivered using a combination of existing transmission interconnection lines, new transmission lines from out of state, and renewable energy credits.

c. What did you assume for Renewable Portfolio Standard developments in the rest of WECC, how much fossil generation was added to replace once-through cooling retirements and how much was added to "back-up" intermittent renewable energy in California and the rest of the WECC?

- The combined renewables target for the rest of the WECC is approximately 14%, which was derived using individual states' renewable targets.
- The Nexant Study assumed the retirement of almost 10,000 MW of once-through-cooling units (excluding nuclear units) by 2020. Both the 20% and 33% cases assumed the same level of once-through-cooling retirements.
- Approximately 2,250 MW of quick-start peaking/load following fossil fuel resources were added to maintain grid reliability and integrate renewables in the 33% case.

d. What major transmission upgrades were included and in what year in California and the rest of WECC?

The study identified the transmission needed to meet a 33% target by 2020, rather than estimating an annual need for transmission. The study did not:

- Conduct a detailed transmission planning analysis,
- Follow the Large Generation Interconnection Procedure (LGIP) to identify the transmission needed to interconnect the renewable generation, and
- Perform a deliverability assessment of the new generation needed to accommodate increased levels of renewable resources.

Accordingly, the Nexant Study may have underestimated the number of transmission projects needed.

Nevertheless, the Nexant Study identified that nine (9) transmission projects are needed to reach a 33% RPS goal:

The following five projects are assumed to be in service in 2020 to help reach the 20% target:

1. Tehachapi Renewable Transmission Project (TRTP),
2. Devers – Palo Verde #2,
3. Green Path North,
4. Sunrise Transmission Project, and
5. Lugo-Pisgah 500 kV upgrades.

The following incremental transmission projects are identified for the 33% case:

6. Kramer-Lugo 500 kV line,
7. Central California Clean Energy Transmission Project (C3ETP),
8. Northern California to Pacific Northwest 500 kV line, and
9. Coachella- Devers 230 kV lines.

Submitted To:
Southern California Edison

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California Renewable Portfolio Standards Study Executive Summary

Submitted By:
Nexant

APRIL 2009

Foreward

This study was performed by Nexant's Software and Information Systems Division for Southern California Edison under P.O. Number 4500044198. Other study participants included San Diego Gas & Electric, and Pacific Gas and Electric.

Nexant gratefully acknowledges the assistance of the National Renewable Energy Laboratory, 3Tier, and General Electric for the supply of wind and solar data, and the California Independent System Operator for providing additional data used in this work.

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Executive Summary

California's Renewable Portfolio Standard (RPS), enacted in 2002 and accelerated in 2006, is one of the most aggressive renewables standards of any state. The current RPS requires that 20% of electricity delivered to customers by investor-owned utilities, energy service providers, and community choice aggregators must come from qualified renewable resources by 2010.

It is quite possible that the RPS requirements will be made more ambitious in the future, as the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) are presently investigating the possibility of a 33% RPS target to be met by 2020. The California Air Resources Board has also identified a 33% RPS as one means of achieving the goals of AB 32, which established the state's goal of reducing greenhouse gas (GHG) emissions in 2020 to the GHG emission levels of 1990. And on November 17, 2008, Governor Schwarzenegger issued Executive Order S-14-08 that calls for a 33% Renewable Portfolio Standard for the state.

There are numerous outstanding concerns and questions regarding the implications of more aggressive RPS requirements. This study–which assumed the 20% RPS requirements were met in 2012 and looked at the state as a whole, not only at California ISO's territory–addresses a subset of these, which may be grouped into the following broad categories:

- What will be the general cost trend or effect of increasing RPS standards on California ratepayers?
- How is the ability to plan and operate the power system affected by the integration of additional renewable generation, and are there limitations as to how fast and how much renewable generation can be implemented in the future?
- How do GHG emissions associated with power supply vary with higher penetrations of renewable resources, and what is the cost of reducing the emissions by increasing the amount of renewables?
- How feasible is it to meet the various RPS targets per the proposed schedules?

The general conclusions reached in the study are:

- Relative to estimated rates for implementing a 20% RPS standard in 2020 and 2025, estimates of the rate impacts are a 6.5-7.6% increase for the 33% RPS case in 2020 and a 16.9-18.9% increase for the 50% RPS case in 2025 (based in part on relatively conservative transmission addition assumptions).
- Since the output of many renewable resources, such as wind and solar, vary according to the availability of the wind or sun, etc., the production from renewable resources is variable and uncertain. To reliably operate the grid given this variability, additional conventional resources with load following and regulation capabilities are required. Traditional measures of generation adequacy—reserve margin and loss-of-load-expectation (LOLE)—may not fully account for renewable resource variability and may no longer be sufficient to describe the ability of generation to satisfy demand and other grid operation needs. Because higher levels of renewable generation require

additional generation resources for load following and regulation, future planning requirements may also need regulation and load following components.

- In order to have sufficient resources for grid operations, between approximately 2,250 MW (33% RPS scenario in 2020) and 3,750 MW (50% RPS scenario in 2020 and 2025) of quick-start peaking/load following resources were required, and the hydro generation was operated more aggressively for load following and regulation than it is currently.
- GHG reduction costs were approximately $160 to $230 (in 2008 constant dollars) per tonne of CO2 reduction. The lower value reflects the cost in the 33% RPS High Wind scenario, and the higher value reflects the cost in the 50% RPS case.
- Anticipated retirement of more than 10,000 MW of existing thermal resources may be delayed in the short term, as there may not be sufficient time to complete the transmission modifications needed to allow more generation to be delivered into the Los Angeles Basin without jeopardizing grid and system reliability.
- Based upon the assumptions used in the study, achieving the 50% RPS target would require at least nine major upgrades to the in-state transmission system beyond what is already planned to meet the 20% standard, plus a new transmission line to the Northwest to import renewable energy from that region. The 33% case would require at least seven upgrades beyond what is already planned, plus the line to the Northwest. These estimates are probably on the low end due to the non-traditional methods used to identify needed transmission upgrades.
- In Nexant's view, the siting and permitting of new generation may delay achievement of RPS goals. Delays are more likely to occur with higher RPS targets, since this could require the construction of additional solar resources in environmentally sensitive desert regions.
- Energy storage provides significant benefits with respect to reducing dump power and reducing fluctuations in output due to changes in wind or solar inputs. The addition of storage to solar thermal generation reduced dump power from 3100 GWh to 821 GWh in the 50% RPS requirement in 2025

Whereas this study was a thorough first step in understanding many of the ramifications that higher levels of RPS resources may impose on the system, the study should be viewed as a starting point for additional work—in conjunction with experience from real-world operations—to understand the effects of increasing RPS requirements on the operations of the grid. The study focused more heavily on understanding the impact of increasing RPS standards on the economics of the power system rather than on operational aspects. Hence, the results of this study cannot be interpreted as the final determination of operational feasibility of the power system. The following caveats should be kept in mind with respect to operational feasibility:

- Additional work must be done to understand the implications of future RPS goals on voltage stability, frequency and tie-flow regulation, load following, transient stability, locational loss-of-load issues, operational effects on thermal and hydro units, and many other operational issues that were not included in the scope of this study or were addressed at a relatively high level.

- This analysis identifies potentially serious issues with operating the power system at the 33% and 50% levels of renewable penetration, which may equate to problems at even lower levels of RPS penetration. The operational violations encountered in the simulations indicate that even with the large time period to adjust to changes in non-dispatchable resources and with perfect foresight, the overall flexibility of the remaining operating generation may be inadequate to operate the grid reliably.
- The overall operational feasibility of these future RPS standards needs further research using smaller time increments to fully understand the ramifications to the grid.
- The results of the study also suggest that the use of a target planning reserve margin, or even a more sophisticated locational loss-of-load target, may by itself be an inadequate measure of generation reliability with high renewable penetration. This is because additional resources are needed to meet the operational ramping and load following requirements created by incremental intermittent and non-dispatchable renewable resources
- In Nexant's opinion, the analysis as performed understates the issue of dump power, in part because hydro generation was operated more aggressively for load following and regulation in the simulation than is done in practice. Further, system commitment and dispatch were performed WECC-wide and with perfect foresight, which ignores coordination issues and sudden events encountered in actual system operation. Future analyses should review the modeling of hydro units and their ramping capabilities; the modeling of commitment and dispatch should consider that these functions are performed on a balancing authority basis and not WECC-wide.
- If further studies determine that dump power has a significant impact on costs and the operability or reliability of the network, then changes to current and future contract structures may be necessary to allow more frequent curtailment of these resources. This will also require the addition of controls on the renewable resources to allow for central control of their output, as well as higher RPS procurement targets for utilities to ensure the RPS standards are met.

EFFECTS OF INCREASING RPS REQUIREMENTS ON RATEPAYERS

Nexant performed a thorough analysis to estimate the increase in customer rates over the 2012-2025 study period as RPS requirements varied. The components of cost included the following:

- The levelized capital costs included costs associated with new generation plants (both renewable and non-renewable) required to meet RPS requirements and load growth. as well as additional costs needed to add capacity sufficient to meet operating and non-operating reserves and satisfy load following and regulation capacity requirements as identified in the production simulation. In this study, Power Purchase Agreement (PPA) terms were based on the economic life of the generation;
- The capital costs of the required new transmission facilities were estimated based on standard transmission capital costs for both bulk transmission and optimized collector systems;

- Variable operating costs – the fuel costs of generation plants located in California and the cost of imports to meet California load – were estimated in the production costing process;
- GHG compliance costs represent the cost or credit to the state as a whole, in cases where credits are purchased when state-wide GHG emission exceeded the AB32 requirement, or where surplus GHG credits are sold if the state-wide GHG emissions were lower than the AB32 requirement.
- All other costs are the costs of operating the electric system not included in the items above, such as capital, operation and maintenance of existing transmission assets, distribution costs, nuclear decommissioning, etc.

Table 1. Breakdown of revenue requirements for 2020 and 2025 for 20%, 33% and 50% RPS ($2008 Billions, annually)

2008 $ Billions, annually	2020			2025		
	20%	33%	50%	20%	33%	50%
Incremental Transmission	0	0.6	1	0	0.7	2
Incremental Generation	0	5	8	0	5	12
Production Costs (Fuel + Imports)	13	11	9	15	12	9
GHG Compliance	0.1	-0.1	-0.2	0.2	0	-0.3
All Other costs	31	31	31	31	31	31
Total	44	47	49	46	49	54

Renewable costs were based on the cost of generation levelized over the economic life of the project rather than on the Market Price Referent (MPR) plus Time of Delivery (TOD) adjustments to the levelized 20-year renewable PPA terms. In developing the revenue requirements for Table 1 above, Nexant assumed that the costs associated with incremental renewable generation additions would be higher on a per-MW basis under the 33% and 50% standards due to increased costs for raw materials, siting and permitting, land, etc. To reflect this, 10% and 20% adders, respectively, were added to the cost of renewable generation in these cases.

The bulk transmission additions were identified using a simplified, non-traditional approach. Nexant estimates that a more traditional transmission planning approach would identify approximately 30% more needed upgrades. Consequently, the transmission cost numbers reported here are 30% higher than the costs of the explicitly identified upgrades.

Production costs decrease with increasing penetration of renewable resources. These decreases are primarily due to reduced fuel consumption for fossil units, as their energy production is displaced by that from the renewable resources.

Greenhouse gas compliance was modeled assuming the utilities would incur additional expenses to purchase credits in cases where they fail to meet reduction targets, but would have additional revenue in those cases where reduction targets were exceeded. In the 33% RPS Case in 2020, for example, California utilities would receive a credit of $0.1 billion from the sale of excess GHG credits.

Tables 2 and 3 show the state-wide rate impacts for the various RPS cases in 2020 and 2025, in 2008 constant dollars. High-costs Base Cases were also established for the 33% RPS Case in 2020, and for the 50% RPS Case in 2025, in order to estimate the upper bound for the costs. For the 33% RPS, it has been assumed that the ultimate 33% target is met in 2020, hence increasing production from renewable resources must only keep up with modest demand growth in the period 2020-2025. In order to assure the 50% RPS target was met by 2025, a 40% RPS target was set for 2020.

It must be noted that the average rates presented in Tables 2 and 3 are state-wide average values, including the rates for municipal and investor owned utilities. The rates for individual utilities or customer classes will deviate from these averages. Debt equivalence was not calculated as part of the revenue requirement calculation.

In addition, financing assumptions regarding the cost of debt and return on equity were assumed to be flat, rather than changing as the Debt-to-Equity ratios would change due to current economic conditions. Leverage assumptions are aggressive and the cost of debt and equity may be low given the associated risk with such high leverage based projects in the current economic environment.

Table 2. Revenue requirements for 2020.

	2020 Revenue Requirements			
	20% RPS	*33% RPS*	*33% RPS High*	*50% RPS*
Revenue Requirement (2008 $B)	44	47	47	49
Average Rate (2008 cents/kWh)	13.83	14.73	14.88	15.58
% Increase from 20%	N/A	6.5%	7.6%	12.7%

Table 3. Revenue requirements for 2025.

	2025 Revenue Requirements			
	20% RPS	*33% RPS*	*50% RPS*	*50% RPS High*
Revenue Requirement (2008 $B)	46	49	54	55
Average Rate (2008 cents/kWh)	13.85	14.70	16.19	16.46
% Increase from 20%	N/A	6.2%	16.9%	18.9%

INTEGRATION, PLANNING, AND OPERATION EFFECTS

A core objective of this study is to evaluate the impacts on planning and operating of the California power system and electricity market resulting from an increase in the amount of renewables from the current 20% RPS level to 33% and 50% RPS levels. The impacts largely arise from the increase in the total variability of the system associated with the general intermittent nature of wind and solar resources. The increased variability has implications on voltage stability, frequency and tie-flow regulation, load following, transient stability, locational loss-of-load simulations, and wear-and-tear effects on thermal and hydro units, among many other issues.

The approach, scope, and results of the study focused on identifying and trying to quantify the magnitude of the impacts driven by increased renewable penetration. Accordingly, the impacts of renewables at the 20% level were determined prior to those for the 33% and 50% levels so that the delta between the impacts could be determined. The primary tool used here for understanding operation of the power system is the PLEXOS™ production simulation software, which looked at steady state generation commitment and dispatch in hourly time steps. While such a tool is primarily used to understand the economics of the power system, it also yields information about the feasibility of operating the system. Nevertheless, significant additional work must be done to better understand the full scope of the implications on system planning and operations from the increased variability of intermittent resources. In particular, additional operational information may be available with more granular time-steps of, say, five minutes, than with the hourly time-steps of this study. The study, therefore, cannot be interpreted as determining the feasibility of operating the power system in a reliable manner under any of the RPS scenarios. Rather, the study should be viewed as a starting point—in conjunction with experience from real-world operations—for additional work to understand the effects of increasing RPS requirements.

Planning Reserve Margin

In order to ensure a reliable supply of energy, generation capacity in excess of peak demand conditions must be installed to account for scheduled and forced outages that might otherwise result in insufficient capacity to meet demand. In California, the typical planning reserve margin is 15-17% over the forecasted peak. An 18% level was used as the target for all of the various cases in this study. "Firm capacity multipliers" were used to de-rate the reliability contribution of wind and solar resources to account for their intermittency. Nameplate capacity times the multiplier gives the firm capacity. The firm capacity multipliers are 10% for wind, 45% for solar photovoltaic and concentrated solar photovoltaic, 56% for solar thermal resources, 95% for solar thermal resources with energy storage, and 100% (i.e., no de-rate) for both biomass and geothermal.

In developing the generation plans, resources were added until both the RPS energy requirements and the reliability requirements were satisfied. In two cases, it was found that capacity was needed in excess of the 18% target. For the 33% RPS in 2020, Nexant established a resource expansion plan favoring solar resources over wind as a sensitivity case. Because the reliability value of solar is high relative to its energy contribution (i.e. solar is available during peak hours when energy is needed most, but these resources do not provide energy without the use of storage), a planning reserve margin of 21% was reached before the RPS energy requirements were reached.

The resource plan for the 50% RPS case in 2025 also resulted in a planning reserve margin near 21%. In this instance, the need for capacity additions occurred due to ramping and load following violations in the production simulation runs. This is a significant finding that points to potentially serious issues in the actual operation of the power system with this level of renewable penetration, and likely at even lower RPS levels. The production simulation operates in hourly time-steps and has perfect foresight of hourly demand changes, production from wind and solar generation, unit outages, and other factors that would affect unit commitment and dispatch. The violations encountered indicate that even with the large time period to adjust dispatchable resources and perfect foresight, the overall flexibility of operating generation is inadequate. In practice, the changes often come without warning and occur over a period of a few minutes, not smoothly over the hour. Thus, this is an area that needs further research in smaller time increments to understand the full operation impacts. In addition, it suggests that the use of a target planning reserve margin, or even a more sophisticated locational loss-of-load target, may by themselves be inadequate measures of generation reliability with high renewable penetration.

Dump Power

The dumping of power occurs when the minimum generation in a region (e.g. baseload nuclear, run-of-river hydro, wind, solar, firm imports, some gas-fired generation for control, etc.) exceeds demand and willing buyers of exports. Dumping implies that some renewable resources must be operated below the level at which they would otherwise operate in order to maintain system frequency and interchange. Energy prices during these events can go to, or even below, zero. During some simulations at higher RPS levels, this occurred several times during on-peak hours when solar production was high. Dump power makes the resources less economic and requires the construction of additional renewable resources to attain the RPS energy goals. Such considerations also indicate that the state would likely have severe operating problems.

Dump power was encountered in production simulations, primarily for the 50% RPS in 2025, where 3,100 GWh (approximately 1% of California's annual load) was dumped. Ninety percent of the dump occurred in the territory of Southern California Edison (SCE), because a large fraction of the planned renewable additions were in this region. It should also be noted that the location of these resources in SCE territory causes increased south-to-north flows into the territory of Pacific Gas & Electric (PG&E) along Path 15, counter to the current prevailing trends. The majority of the dumping occurred in the March-May timeframe, since during this period, hydro, wind and solar resources all operate at higher output levels.

The substitution of solar thermal generation with storage in place of other, more intermittent solar resources, reduced dump energy to 821 GWh in the 50% RPS simulation in 2025.

In Nexant's opinion, the analysis as performed understates the issue of dump power, in part because hydro generation was operated more aggressively for load following and regulation in the simulation than is done in current practice. Absent this aggressive use of hydro resources, additional fossil resources would need to be committed, which could potentially exacerbate over-generation. Furthermore, system commitment and dispatch were performed WECC-wide and with perfect foresight, which ignores coordination issues, limitations due to existing contracts, and sudden events seen in actual system operation. Future analyses should review the modeling of hydro units and their ramping capabilities; simulation of commitment and dispatch should consider that these functions are performed on a balancing authority basis and not WECC-wide.

Lastly, dumping renewable energy would require adding more renewables, thus producing more dump energy. This may signal that the incremental value of more renewable power is very low without more cost effective storage options in the future.

If further studies determine that dump power has a significant impact on costs, the operation of renewable resources or on reliable operation of the power system, changes to current and future contract structures may be necessary to allow more frequent curtailment. This will also require the addition of controls on the renewable resources to allow for central control of their output.

Regulation

Control area operators must maintain sufficient generation on automatic generation control to follow the short term variations in load and generation in order to regulate the system within the prescribed NERC/WECC control performance standards. With increasing levels of wind generation, the requirement for regulation both in the up direction (Regulation Up) and the down direction (Regulation Down) are increased. The results of the analysis are shown in Tables 4 and 5, below, for the 50% RPS in 2025 and the 33% RPS in 2020, respectively.

Table 4. Regulation Requirements for the 50% RPS in 2025

	Winter	Spring	Summer	Fall
Regulation Up	1031	1023	843	847
Regulation Down	1092	1076	1017	889

Table 5. Regulation Requirements for the 33% RPS in 2020

	Winter	Spring	Summer	Fall
Regulation Up	541	541	476	467
Regulation Down	559	571	533	486

These results are not as dramatically different from today's 350 MW regulation up and 350 MW regulation down requirements as was seen in the CAISO's November paper. This is likely due to the use of more diverse wind sites in this work, and more solar additions relative to what was used in the ISO's work. Nevertheless, the results indicate that the CAISO and other balancing authorities will face significant challenges in meeting performance standards.

Ramping

Tables 6 and 7 compare the estimated maximum morning and evening ramps for the 20%, 33% and 50% RPS requirements in 2025 to the observed maximums in 2006. It must be noted that the estimated 2025 values are for state-wide changes, whereas the 2006 values are for CAISO only. This difference tends to overstate the difference in the three-hour ramping requirements. Further, these values are only for changes in load and from wind generation.

Table 6. Maximum Morning Ramps for 2025 Compared to 2006

	Morning Ramps, MW			
	2006	2025 20% RPS	2025 33% RPS	2025 50% RPS
Winter	7,000	10,200	12,200	15,100
Spring	6,900	11,000	13,300	16,500
Summer	10,100	17,800	18,700	20,200
Fall	7,200	11,000	12,000	14,500

Table 7. Maximum Evening Ramps for 2025 Compared to 2006

	Evening Ramps, MW			
	2006	2025 20% RPS	2025 33% RPS	2025 50% RPS
Winter	7,900	11,100	12,400	14,400
Spring	8,000	11,100	12,000	13,700
Summer	10,600	15,900	16,100	16,500
Fall	11,500	14,700	14,700	14,700

The ramps for both morning and evening periods are expected to be much greater in 2025 than those observed in 2006. Load growth accounts for approximately 25% of this change; the rest is due to contributions from wind. Changes in wind output often exacerbate the ramping issue, decreasing in the morning as load increases, and increasing during the evening when load decreases.

GREENHOUSE GAS REDUCTIONS

The CO2 emissions attributable to the electric power sector in California were calculated as the sum of emissions from generators located in California plus the emissions associated with imports of electric power (both specified imports from California owned generation located outside of California and unspecified imports). These were compared to the emissions from the 20% RPS cases in the relevant year. The values were also compared to the 1990 GHG emissions reference of 86.4 million tonnes, which must be achieved by 2020 under AB 32.

The emissions estimated in the 33% RPS scenario are reported in Table 8. As expected, emissions declined compared to the 20% RPS scenario, due to an increase in renewable energy generation, and a commensurate decrease in fossil fuel generation. The 20% reference levels in 2020 and 2025 were 97.1 million tonnes, and 102.9 million tonnes, respectively, both exceeding the 1990 reference level. Overall in the 33% RPS scenario emissions declined by 16 million tonnes in 2020, and by 16.6 million tonnes in 2025, compared to the 20% scenario. In both 2020 and 2025, the estimated level of emissions is below the 1990 emissions level. Approximate costs for the reductions of CO2 were $160 per tonne in 2008 constant dollars.

Table 8. CO2 Emissions, 33% Scenario

			Deviation from 20% Scenario	
Name	33% RPS	33% RPS	33% RPS	33% RPS
Year	2020	2025	2020	2025
CA Emissions ('000 Tonnes)	45,320	50,480	-11,581	-13,152
Specified Imports Emissions ('000 Tonnes)	24,078	24,058	-441	-486
Unspecified Imports Emissions ('000 Tonnes)	11,701	11,682	-3,996	-3,020
Total Emissions ('000 Tonnes)	81,099	86,220	-16,017	-16,658

Table 9. Emissions 50% RPS Scenario

Name	50% RPS Target (40% actual)	50% RPS	Deviation from 20% Scenario 50% RPS	Deviation from 20% Scenario 50% RPS
Year	2020	2025	2020	2025
CA Emissions ('000 Tonnes)	38,936	38,513	-17,965	-25,119
Specified Imports Emissions ('000 Tonnes)	23,748	22,442	-771	-2,102
Unspecified Imports Emissions ('000 Tonnes)	9,950	2,150	-5,747	-12,553
Total Emissions ('000 Tonnes)	72,634	63,105	-24,483	-39,774

The emissions estimated in the 50% RPS scenario are shown in Table 9 above. Emissions from all sources (California generation, specified imports and non specified imports) all declined by significant amounts, compared to the 20% RPS scenario, due to an increase in the amount of generation from renewable energy sources, and a corresponding decrease in fossil fuel generation. In both 2020 and 2025, the estimated level of emissions is well below the 1990 emissions level. Approximate costs for the reductions of CO2, which were the result of the higher renewable levels, were $230 per tonne, in 2008 constant dollars. Resource dispatch and emission levels could vary significantly depending on the CO2 price assumed. This study assumed $8/tonne in 2004 with a 4% annual escalation factor.

FEASIBILITY

California's current 20% Renewable Portfolio Standard is among the most ambitious in the United States. Increasing the standard to 33% or 50% will make it more difficult for entities subject to the RPS to meet the goal on time. Nexant investigated several factors that may contribute to schedule (not technical) infeasibility.

Transmission

Based upon the assumptions used by Nexant, achieving the 50% RPS target would require at least nine major upgrades to the in-state transmission system. Nexant also assumed that a new transmission line would be built to the Northwest to import renewable energy from that region. The 33% case would require at least seven upgrades incremental to lines already planned, plus the line to the Northwest. As mentioned previously, these estimates are probably on the low end due to the non-traditional methods used to identify needed transmission upgrades.

The duration required to add new transmission in California may be approximated as follows:

- Project study and approval by CAISO, 1-2 years
- CPUC approval, 2-3 years
- Engineering and procurement, 1-3 years
- Construction and environmental mitigation, 2-3 years

This yields a typical lead-time of 6-11 years for a transmission project. However, both the CPUC requirements and environmental mitigation steps can become much more extensive and prolonged, as has occurred with San Diego Gas and Electric's Sunrise transmission project, for example. In Nexant's view, delays in transmission additions are likely to cause delays in achieving the RPS targets on time.

Generation Siting and Permitting

Achieving the RPS targets will require the addition of large amounts of new generation facilities. This fact is exacerbated by expected retirements, largely in order to eliminate once-through-cooling, of 46 thermal units totaling 9,629 MW before 2020. Figure 1 shows the capacity additions for each RPS scenario in 2025. [Note that in the Figure "Other Resources" refers to resources in place before 2012 and imports over interties.]

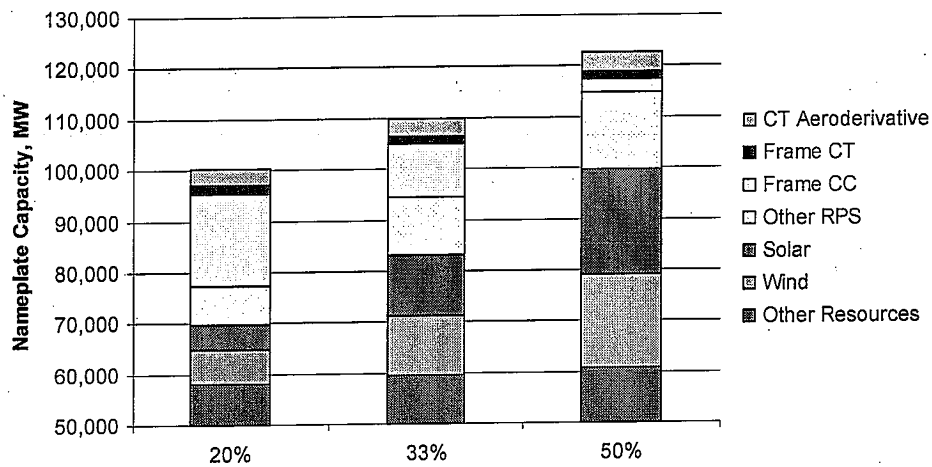


Figure 1. Resource plans for 2025 for the various RPS targets.

RPS resources present significant siting and permitting challenges; for example, the land required for solar facilities would be expansive. Under the 50% RPS, Nexant estimates that solar facilities would occupy 250 square miles of land, and many of the most attractive sites in the Mojave Desert are under the management of the Federal Bureau of Land Management (BLM). The BLM and CEC are required to review applications for all facilities larger than 50 MW. At present approximately 125 such projects are under review, but so far none have been approved. Recent comments from the BLM suggest that they are likely to permit fewer than 30 of these projects in the foreseeable future.

Siting and permitting challenges will exist even at the 20% RPS target, which would require 22.8 GW of new thermal generation. In Nexant's view, the siting and permitting of new generation may delay achievement of RPS goals. Delays are more likely to occur with higher RPS targets, since this could require the construction of additional solar resources in environmentally-sensitive desert regions.

RECOMMENDATIONS

Based on the results of this study, Nexant recommends the following with respect to the planning and operation of the power system under higher levels of RPS requirements:

- The unpredictable and intermittent nature of renewable resources, particularly solar without energy storage and wind, requires that the flexibility of other resources (including thermal, hydro, geothermal, etc.) be considered as a factor in the long- and mid-term resource planning process. Here, flexibility refers to the startup time, maximum upward and downward ramp rates, and minimum output levels of the units, and the costs associated with achieving this performance. This may include development of explicit criteria for quantifying flexibility requirements and inclusion of these criteria in the process. These factors are likely to be used to determine if one's portfolio will be sufficient to meet the system's requirements for flexibility on a planning basis.
- Control systems for the system operators to quickly curtail wind or solar generation in the event that over-generation has not been resolved prior to real time should be addressed. This would include the need to equip all new wind and solar generation with SCADA type controls that allow for rapid remote curtailment (without manual intervention). It would also require that contracts with all new wind and solar generators require the installation of this equipment and include the commercial terms associated with its use. As the opportunity and need arise, steps should be taken to add such controls and commercial provisions to existing wind and solar projects.
- Further work should be done to quantify the benefits of coupling storage with renewable resources. In particular, solar thermal generation with storage appears to present several valuable benefits, including high storage efficiency, reduced over-generation, the ability to ride through periods of cloud cover without changing output, and the ability to co-fire with gas to provide a capacity benefit. The dispatchability of this type of generation—which was not fully modeled or captured in this study—may also help resolve system impacts related to intermittency including the need for increased ramp rates on other generation. The study results show that solar with storage may not be significantly more expensive than solar without storage on a $/MWhr basis.
- The costs and benefits of using probabilistic planning methods for transmission planning should be examined, particularly for the renewable collection systems. Such planning should consider that wind and solar facilities do not all produce at peak generation levels simultaneously, allowing for lower levels of investment or more rapid deployment of renewables based upon this natural production diversity.
- The forecasting of seasonal renewable generation should be improved to assist with short term system planning and over-generation forecasting. The results of these studies could also be used to improve the WECC-wide understanding of over-generation potential
- The CAISO should continue its program of requiring telemetry to monitor the output of new renewable resources (under PIRP), and should expand this program to require monitoring of all existing such resources.
- Real time analysis tools should be developed to provide operators with near real time insight into over-generation issues and mitigation options and the need for curtailing renewables due to local transmission limitations.

- The CAISO should incorporate wind and solar forecasts into the day-ahead market process.
- The CAISO and other planning entities in California should maintain close relationships with each other and WECC regarding renewable resource planning and operating procedures.

With respect to modeling and further studies of the higher RPS requirements, Nexant recommends the following:

- Further refine the modeling of hydro and pumped storage unit capability with regard to reserves, load following and regulation.
- Further refine the modeling of Must Take and Must Run for reliability units as they impact the potential for over-generation.
- Further refine the modeling of units that can be available to provide reserves, load following and AGC capability in the future.
- Examine system conditions under high hydro conditions to determine the requirements for reserves, load following and regulation.
- Examine the dynamics of solar generation with and without storage including the potential load forecast errors and potential for large loss of solar generation due to extended cloud cover or other events.
- Examine the potential for dispatching solar thermal storage to mitigate the impact to ramping and reduce the potential for over-generation and develop a solar-with-storage dispatch model for these future modeling efforts.
- Examine the potential for over-generation under a range of scenarios including high hydro with the model improvements listed above.
- Examine the impact to the resource adequacy process due to increased levels of renewables.
- Studies of the need for load following be increased and focus on the near and long term to allow for reflecting the study results in the commercial procurement processes used by utilities to make additions to the portfolios.
- Modeling of unit commitment and system dispatch by balancing authority rather than WECC-wide.

Higher Renewable Portfolio Standards Study

(Nexant Study)

Joint Study by IOU's

Presentation Outline

- Executive Summary
- Study Overview
- Study Conclusions
- Revenue Requirements and Rates
- Other Study Results
  - Dump Energy
  - Integration issues
  - Transmission Expansion
  - Emissions
- Generation and Transmission Feasibility
- Nexant Recommendations
- Study Input Assumptions

Executive Summary

Study Overview

- Performed an independent analysis of the cost, rate and operational effects of potential state-wide RPS levels of 20%, 33% and 50%

Study Conclusion

- California rate increases in 2020 are in the range of 7-11% for a 33% RPS case
- It is not evident that sufficient transmission development can be achieved to reach a 33% RPS target by 2020
- Flexible, fast response resources; storage technology; and better coordination is needed to integrate higher levels of renewable resources

Study Overview

- Nexant Consulting performed an independent analysis in the summer and fall of 2008 that analyzed the effects of future RPS levels of 20%, 33% and 50% in California

- Study participants included the three California IOUs, with input from the CAISO

- Objectives were to evaluate:
  - Renewable resource availability in California
  - Statewide cost and rate impacts
  - Transmission and generation expansion requirements
  - RPS integration (grid operational issues)
  - Construction and technical feasibility

- This study did not attempt to:
  - Determine the optimal mix and locations of renewables
  - Optimize central station versus distributed generation

Study Conclusions

Renewable resource availability in California

- There appears to be sufficient potential renewable generation that can be developed to meet the study RPS targets
- Timely siting and licensing for all the required RPS projects is still uncertain

Statewide cost and rate impacts

- Rate increases in 2020 are in the range of 7-11% for a 33% RPS case
  - Costs may be slightly higher due to current financing and debt equivalence issues, which were not included in the Nexant study

Transmission and generation expansion requirements

- It is not evident that sufficient transmission and generation development can be achieved to reach a 33% RPS target by 2020

Dump Energy concerns

- Intermittent renewable integration and dump energy issues start to develop at 33% and significantly worsen at 50% RPS levels

Construction and technical feasibility

- Sufficient wind development may be feasible
- Solar development may be problematic
- The development of new peaking fossil plants or storage, for operational integration, is critical

Estimated Revenue Requirements

- There are many differences in the methods used for various analyses of 33% RPS in California
  - Must make uniform comparisons – studies often have different 20% RPS base cases.
  - The Nexant assessment was based on July 2008 input assumptions, simulation model output for production costs, and a simplified transmission flow analysis
  - The CPUC GHG study was a simplified spreadsheet assessment (E3 consulting) that did not use any production simulation analysis and did not perform any transmission flow analysis
  - Neither assessment did a detailed transmission planning analysis

- Based on the expected range of renewable costs, and expected transmission requirements, the California rate increase for a 33% RPS scenario in 2020 should be in the range of 7 – 11%
  - The SCE rate increase may be smaller as SCE has a higher level of renewables than the rest of the state
  - New transmission costs will be shared by everyone in the CAISO as TAC charges

20% RPS Scenario Revenue Assessment

2020 California Revenues and Rates
(2008$)

	CPUC GHG Modeling[1]	Nexant Study[2]	SCE Adj. to Nexant Study[3]
Total Revenue Requirement	$47.3 Billion	$43.8 Billion	$44.7 Billion
Rate (cents/kWh)	14.9 cents/kWh	13.8 cents/kWh	14.1 cents/kWh

[1] Based on state load of 318,000 GWh in 2020

[2] Simplified E3 study done for the CPUC regarding GHG mitigation cost estimates corrected to match Nexant study sales

[3] More detailed analysis of renewable generation and transmission needs

[4] Includes debt equivalence mitigation costs, based on SCE's financing assumptions, with contract costs adjusted for utility-type contract terms and MPR+TOD RPS pricing.

33% RPS Scenario Revenue Assessment

2020 California Revenues and Rates
(2008$)

	CPUC GHG Modeling[1]	Nexant Study[2]	SCE Adj. to Nexant Study[3]
Total Revenue Requirement	$53.7 Billion	$46.7 Billion	$49.7 Billion
Rate (cents/kWh)	16.9 cents/kWh	14.7 cents/kWh	15.6 cents/kWh
% Rate Increase (Incremental to 20% RPS)	13.5%	6.6%	11.1%

[1] Based on state load of 318,000 GWh in 2020

[2] Simplified E3 study done for the CPUC regarding GHG mitigation cost estimates corrected to match Nexant study sales

[3] More detailed analysis of renewable generation and transmission needs

[4] Includes debt equivalence mitigation costs, based on SCE's financing assumptions, with contract costs adjusted for utility-type contract terms and MPR+TOD RPS pricing.

Other Study Results

- Dump Energy
- Ramping and Regulation
- Transmission Expansion Study Limitations
- Transmission Expansion
- GHG emissions
- Generation and Transmission Feasibility

Higher RPS is likely to lead to significant amounts of dump energy in the SCE territory.

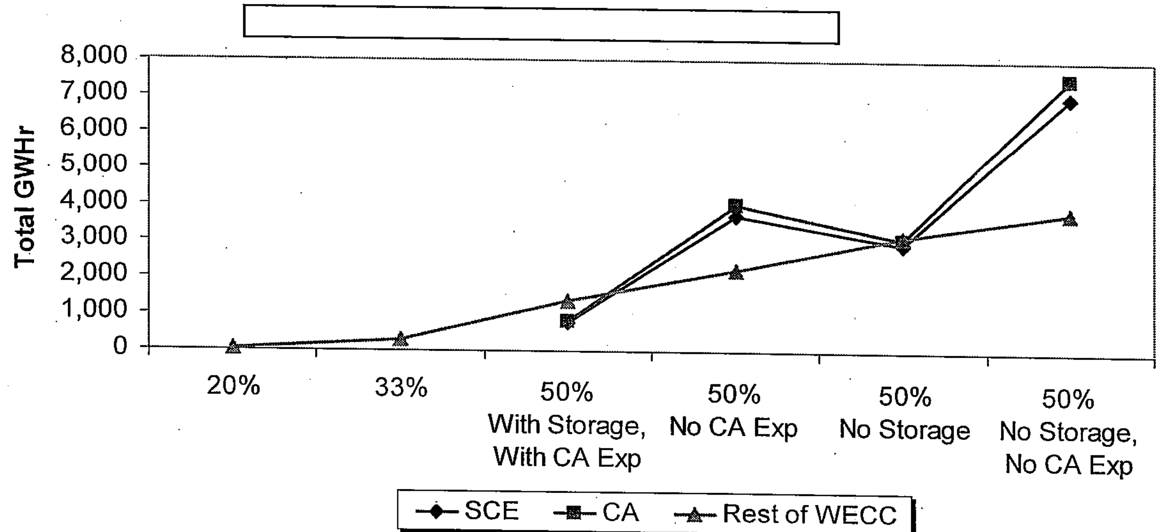
Dump energy *is the excess generation that creates a load-gen imbalance. It occurs when the generation within California and the firm imports into California exceed California's load and export capability to willing buyers outside California. Currently, system operators curtail wind power output on a pro-rata basis to eliminate dump energy, effectively increasing the total capacity required for RPS compliance.*

- Nexant Study Observations
  - Dump energy typically occurs in the springtime when must take energy from hydro, wind, and solar can all be at relatively high output levels
  - More than 90% of the dump energy was observed in SCE's territory due to the territory's high penetration of renewables
  - Dump energy may still be underestimated as the model's simplified algorithm optimizes on a WECC-wide basis, meaning generation out of the state will always back down to take surplus California power
- Dump energy could be reduced by:
  - Adding storage capabilities to solar resources[1]
  - Lowering the minimum output limits (P_{min}) on existing CC's and CT's
  - Changing the structure of current and future contracts to allow more frequent curtailment
- If CHP expansion occurs, dump energy could increase significantly

1 The addition of solar storage reduced California's dump energy from 3,100 GWh to 821 GWh in the 50% RPS scenario.

Energy storage integrated into the transmission grid is helpful in reducing the amount of grid dump energy.

Dump Energy, 2025



- Without the addition of storage technologies, a 50% RPS results in substantial dump energy throughout the WECC in 2025
  - Within California, ~3,100 GWh would need to be dumped
  - SCE's territory accounts for the majority of California's dump energy, totaling 3,000 GWh or 2% of total load
  - Throughout the rest of the WECC, over-generation totaled ~3,200 GWh
- The addition of storage to solar thermal resources in this study reduced dump energy by ~75%, but any type of bulk grid storage would be helpful in this regard

Energy storage technologies may be pivotal in limiting dump energy

Flexible and fast response resources are needed to meet ramp requirements and regulate the grid.

Ramp & Regulation Requirements

	Morning Ramps**, MW				
	2006	2013 20%	2025 20%	2025 33%	2025 50%
	Historical	CAISO study*	Nexant		
Winter	6,979	8,631	10,243	12,184	15,110
Spring	6,860	8,494	10,967	13,272	16,512
Summer	10,090	12,664	17,823	18,727	20,241
Fall	7,229	8,995	11,016	11,950	14,470

	Evening Ramps***, MW				
	2006	2013 20%	2025 20%	2025 33%	2025 50%
	Historical	CAISO study*	Nexant		
Winter	7,856	9,293	12,090	13,483	15,501
Spring	7,962	9,788	11,854	13,497	15,852
Summer	10,589	12,135	15,938	16,330	16,885
Fall	11,511	13,483	14,167	15,851	18,303

- New quick-start peaking/load following resources will be required:
  - At least 2,250 MW under a 33% RPS in 2020, and
  - At least 3,750 MW under a 50% RPS in 2025
- Regulation requirements will nearly triple under a 50% RPS in 2025 with 929 MW of Reg Up and 1,030 MW of Reg Down as compared to current regulation needs of ~350 MW in either direction

* Source: CAISO Renewable Integration Study

** Morning Ramps: Spring & Fall: Hour-Ending 7 (HE7) – HE9; Summer: HE8 – HE10; Winter: HE6 – HE8

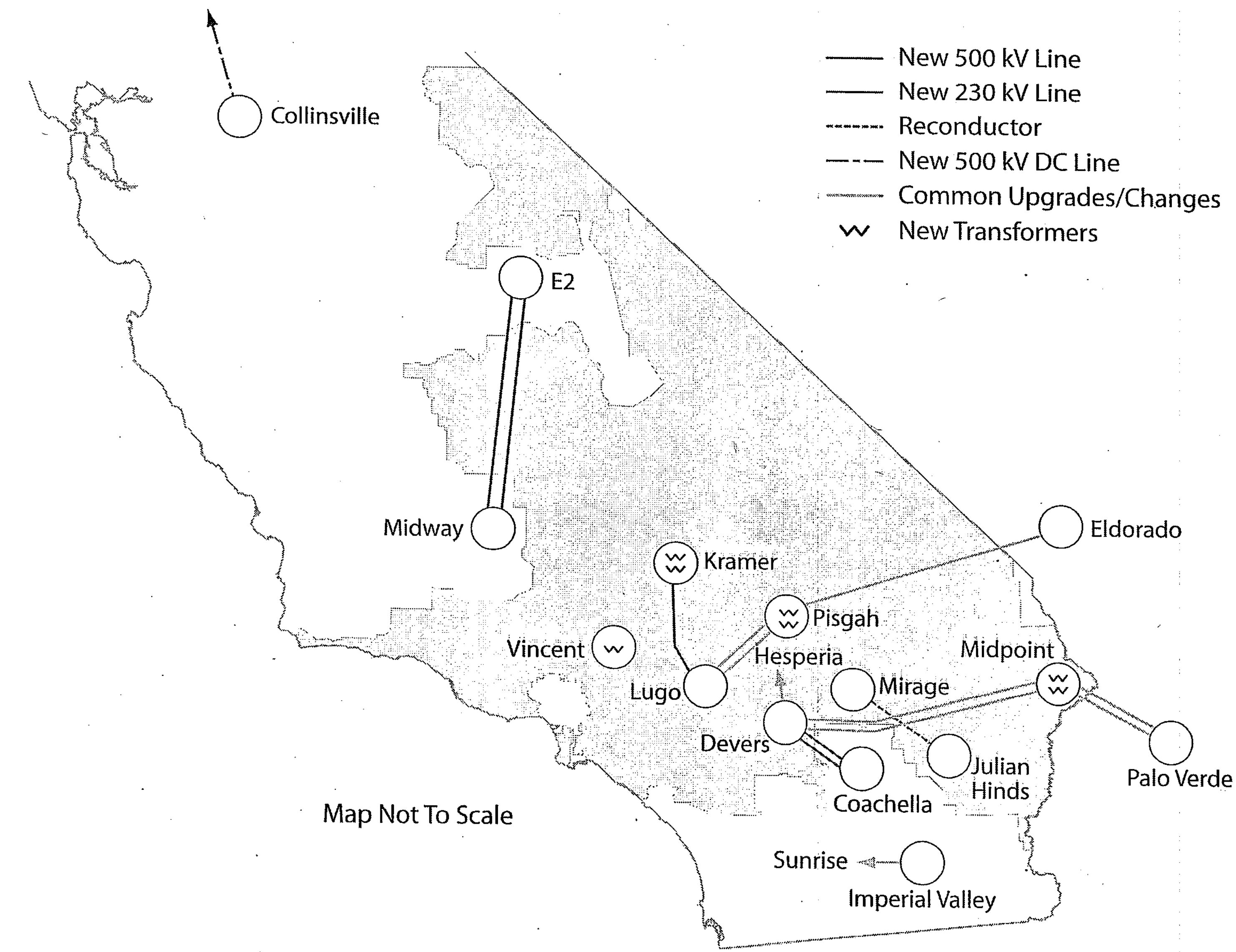
*** Evening Ramps: All Seasons: HE22 – HE24

The study did not follow the traditional planning approach in the transmission expansion analysis.

Transmission Expansion Study Methodology & Limitations

- Expansion study methodology
  - The study deviated from the traditional study methods used by IOU's (load flow, transient stability, short circuit analysis, etc.), as just two load flow studies were performed on the 2025 50% RPS case – one at the time of the system peak and another during a period of high renewable generation
  - The other RPS case results were adapted from the 50% RPS case conclusions per Nexant's professional judgment
  - The transmission studies did not address the deliverability of all of the generation as this is typically performed by the CAISO
  - Generator-tie and collector system costs were modeled in detail
- Implications on resulting transmission upgrade requirements and costs
  - In order to adjust the cost estimate for the upgrades required by the battery of transmission studies typically performed by IOUs, transmission costs were subject to a 30% adder

Transmission Expansion - 33% RPS Case 2020



The incremental shift to a 33% RPS results in a 16.5% reduction in California's GHG emissions at a cost of $180 per metric ton in 2020.

California GHG Emissions in 2020

	33% RPS	Deviation From 20% RPS	
2020 GHG Emissions	*000's of Metric Tons*	*000's of Metric Tons*	*Percentage*
California Generation Emissions	45,320	–11,580	-20.0%
Specified Imports Emissions	24,080	– 440	-1.8%
Unspecified Imports Emissions	11,700	–4,000	-25.5%
Total GHG Emissions	**81,100**	**–16,020**	**-16.5%**

Incremental cost of CO_2 abatement:

$180/metric ton

Feasibility of Renewable Generation Integration

- The system operation appears feasible based on hourly production simulation, but the modeling:
  - Over-optimizes relative to actual performance due to perfect foresight
  - Can almost always be made to work using sufficient resources in model
  - Did not use detailed transmission information and relied on significant exports
  - Looks at hourly time steps, which miss some shorter term events
  - Ignores numerous important factors, e.g. voltage issues
  - Is highly reliant on increased use and flexibility of existing hydro generation
  - Requires increased flexibility to deal with morning ramps
  - Requires additional flexibility and control of solar and wind in real time
- Additional studies are needed to assess:
  - Over-generation analysis under a wider range of system conditions
  - Operational studies with more realistic generator operational limits
  - A more detailed transmission analysis
  - A planning reserve margin loss-of-load analysis (currently underway at the CAISO)
  - Better understanding of the likelihood and impacts of changes in solar radiance (cloud cover)

More Analysis is Required to Fully Assess Integration Feasibility

The process of siting and licensing new transmission lines can potentially lead to multi-year delays.

Feasibility of Transmission

- The typical lead-time for major transmission projects is 6-11 years (based on the location and length of the project)

- The typical process involves:
  - Project study and approval by CAISO (1-2 years)
  - CPUC approval (2-3 years)
    - Can cause significant delays, e.g., delayed approval of Sunrise Project
    - Other litigation post CPUC approval can also delay the project
  - Engineering/Procurement (1-3 years)
  - Construction/Environmental Mitigation (2-3) years
    - Delays could be based on the route modifications and the degree of environmental mitigation required

Potential source of multi-year delays

Within generation siting and permitting, there are many sources of multi-year delays.

Feasibility of Generation Siting and Permitting

- Land area for solar is typically 8 acres/MW
  - A 50% RPS goal implies 250+ square miles for solar developments
- Solar thermal > 50 MW needs BLM and CEC approval
  - Of the 25 projects in CA the BLM has to review, zero have been approved

> **"I don't see us putting 80 solar projects on BLM land, there's no way. I don't see us putting 30."**
> **--Greg Miller, BLM**

- 20% RPS requires 14,300 MW of new gas fired thermal generation in 2020
- 33% RPS requires 11,300 MW of new gas fired thermal generation in 2020

Potential Source of Multi-Year Delay

Nexant Recommendations

Resource Selection

- Flexible and fast-response resources are preferred in order to help respond to expected intermittent resource output
  - Fast start, fast ramp, low minimum output
  - Implied bias towards LMS100-type combustion turbines
  - Modifications to existing CCs might allow attainment of lower minimum output
- Improve control of renewable production
  - Solar thermal units with storage reduce fluctuations with cloud cover, are somewhat dispatchable, and help reduce issues related to over-generation
  - Control of output or storage would provide a better operational fit with current system load shapes
  - Real-time control for all new units would greatly assist operations

Forecasting

- Need to integrate improved wind and solar forecasts into day-ahead scheduling
- Must require new renewables to participate in the ISO's Participating Intermittent Resources Program (PIMS)

Coordination

- Must maintain close relationships with other WECC control areas regarding renewable resource planning and operating procedures

More analysis will yield more operational information

Input Assumptions

- Out-of-State renewables
- Fossil Retirements
- Locations for new renewables

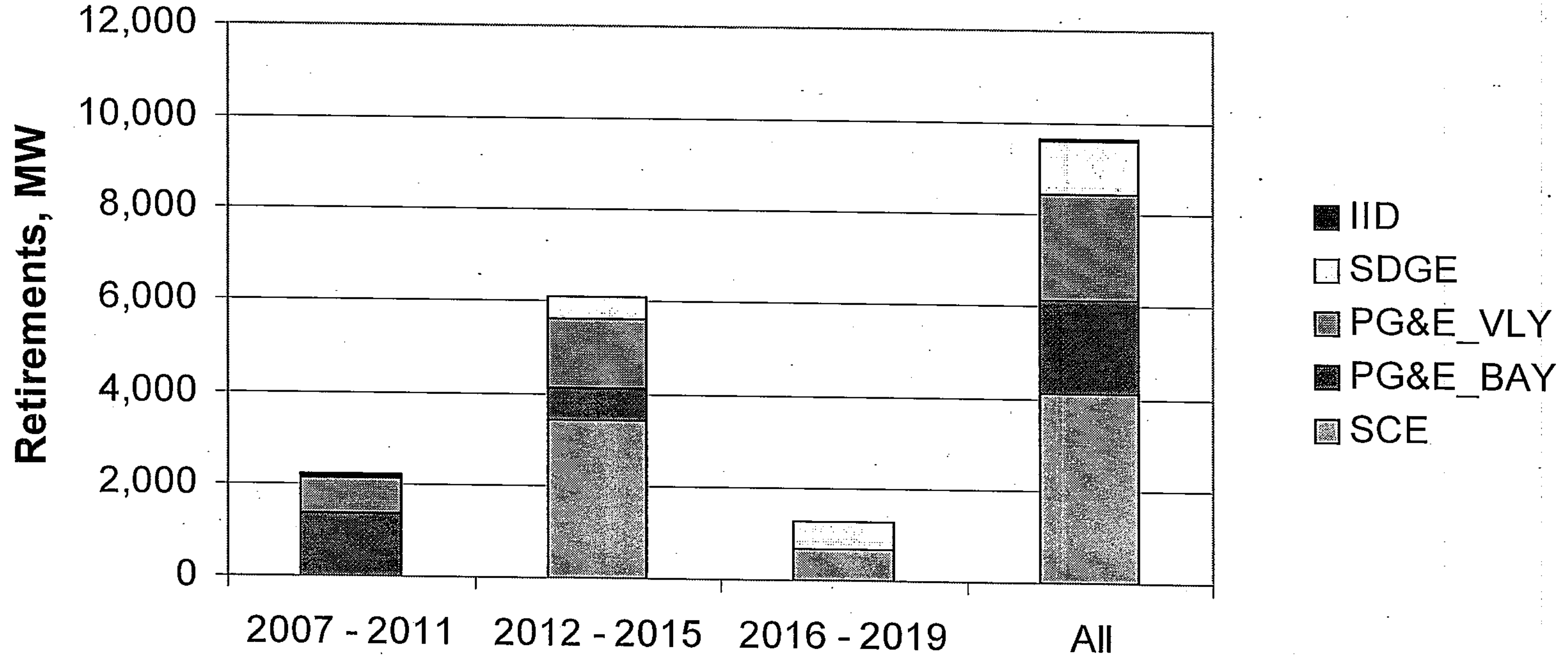
Out-of-State Renewables

- Out-of-State generating plants
  - California utilities ownership of 18 out-of-state non-RPS power plants with a total firm capacity from 6,600 to 6,900 MW was maintained
  - Total firm capacity available over interties into southern California was assumed to be 10,000 MW
- Assumed Out-of-state RPS (MW) were as follows:

	Over Existing Intertie	Over New Intertie	RECs
2012, 20%	946		724
2020, 33%	1,552	1,000	1,224

* Modeling assumptions were established in July 2008

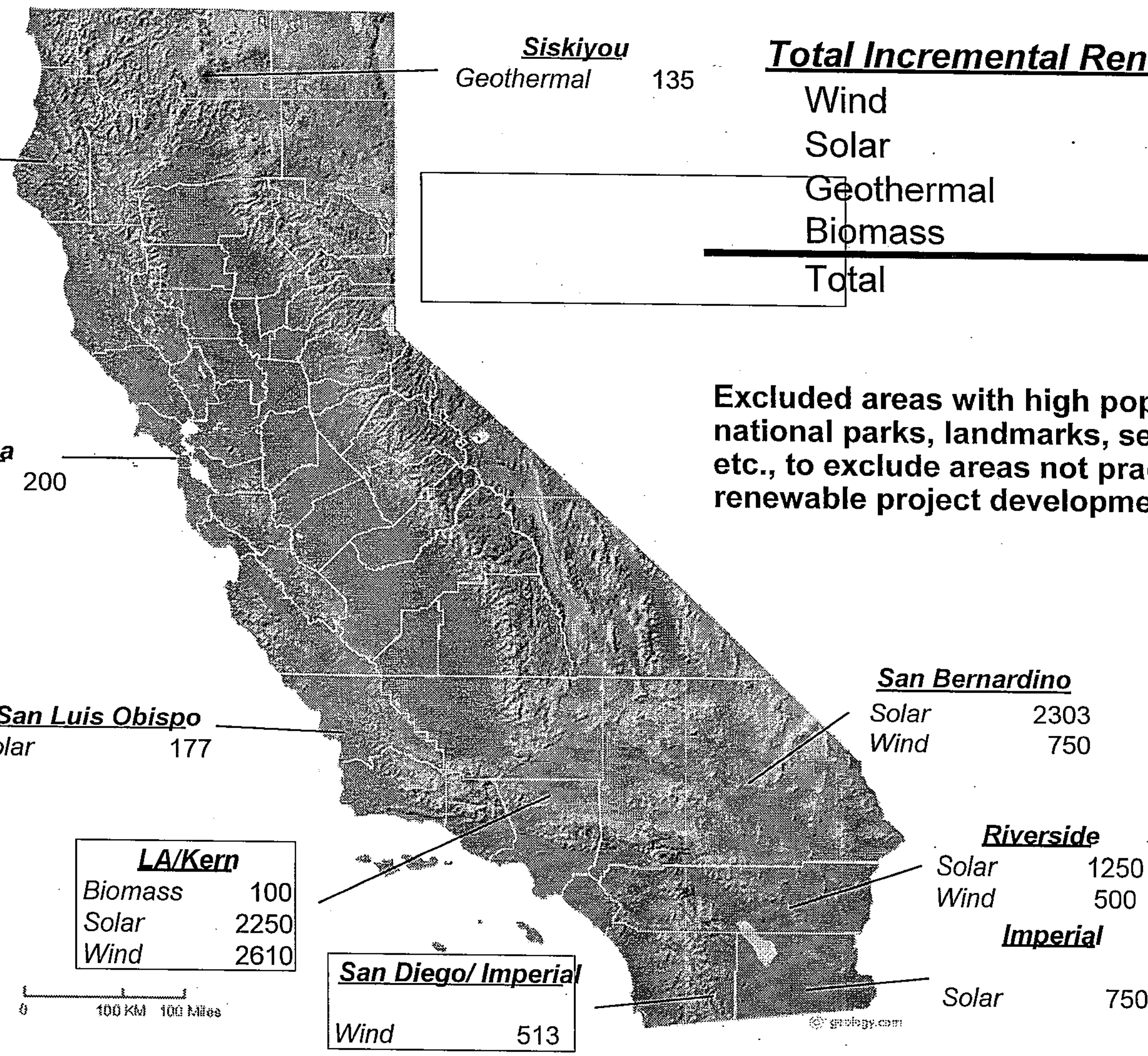
Fossil Unit Retirements



The three IOUs provided information about potential unit retirements, which resulted in retirement of approximately 9,500 MW of existing generation (primarily OTC units) by 2020

(Nuclear units were assumed to obtain license extensions as needed to operate beyond 2025)

Incremental Renewables* - 33% RPS in 2020



Total Incremental Renewables (MW)	
Wind	4,373
Solar	6,730
Geothermal	135
Biomass	300
Total	11,538

Excluded areas with high population density, national parks, landmarks, sensitive areas, etc., to exclude areas not practical for renewable project development

* Incremental to 20% RPS case in 2020

Backup

General Input Assumptions

- November 2007 CEC 2008-2030 California state demand forecast
  - Includes on-going conservation efforts
  - Energy use grows 1.1%/year, peak demand grows 1.2%/year
- Natural gas forecast per 2008 California Gas Report, approximately $7.13-$7.78/MMBtu, burner tip in CA, 2008 dollars
- Added approximately 2,700 MW of Solar PV and Solar CPV by 2020 in the 33% case
- Some RPS renewables were located outside of the state (one third as RECs, one third delivered over existing interties, one third delivered over new interties)
  - 1,700 MW in 2012, 20% case; 3,800 MW in 2020, 33% case; 4,800 MW in 2020, 40% case
- Incorporated California RPS targets for all CA munis and the other WECC entities had their own targets
- State-wide retirements of approximately 9,500 MW of existing generation by 2020, mostly once through cooling units
- Load and wind generation were time-synched to 2006 data for use in the PLEXOS production simulation modeling and the operational and transmission analysis
  - Solar used a "typical" data set from NREL for Southeast California
- 20% RPS serves as reference case throughout
  - 2012 20% RPS case common to all

General Input Assumptions (cont'd)

- GHG prices from CPUC were assumed to grow annually at 5% (nominal) from $8/tonne in 2004
  - $11.82, $17.46 and $21.96 in 2012, 2020, 2025 respectively
- All financial assumptions and results are expressed in 2008 dollars
- New transmission that was common to all cases
  - Interstate transmission line from the Northwest (1,000 MW for the 33% case)
  - Palo Verde - Midpoint - Devers #2 and Sunrise Projects assumed to be operational by 2012
  - New Pisgah – Lugo line and existing El Dorado – Lugo 500 kV line looped into Pisgah was assumed to be operation by 2012
  - Green Path North was assumed to be operational in 2020
- The analysis was performed at a state-wide level
  - Resources were added to meet state RPS and planning reserve requirements
  - Commitment and dispatch was modeled as a state-wide system and not a CAISO system
    - CAISO represents roughly 75% of the state, so the effects of this assumption were modest
  - Results were not disaggregated by utility

Load Forecast

- CEC's November 2007 demand forecast
- The CEC forecast was distributed among zones
- FERC Form 714 data from 2006 was used for hourly load shapes for CA zones and neighboring utilities
- The demand shape and hourly wind production was used to generate synchronized demand
- The TEPPC 2017 data base, released in April 2008, was used for hourly load shapes for the rest of the WECC zones

Generation Planning – Case Summaries

Year	RPS Requirement	Sensitivity
2012	20%	**Base**
2020	20%	**Base**
		High Gas
	33%	**Base**
		High Wind
		High Solar
		No Solar Storage
		High GHG
		High Gas
	40%	**Base**
		High Gas
2025	20%	**Base**
		High Gas
	33%	**Base**
		High Gas
	50%	**Base**
		High Gas

- For the High Gas sensitivities, $2 was added to all gas prices
- The ratio of Wind/Solar additions after 2012 was 70/30 in High Wind sensitivity, and vice versa for High Solar case. The Base case was about 50/50.
- All thermal solar included molten salt storage unless noted otherwise.

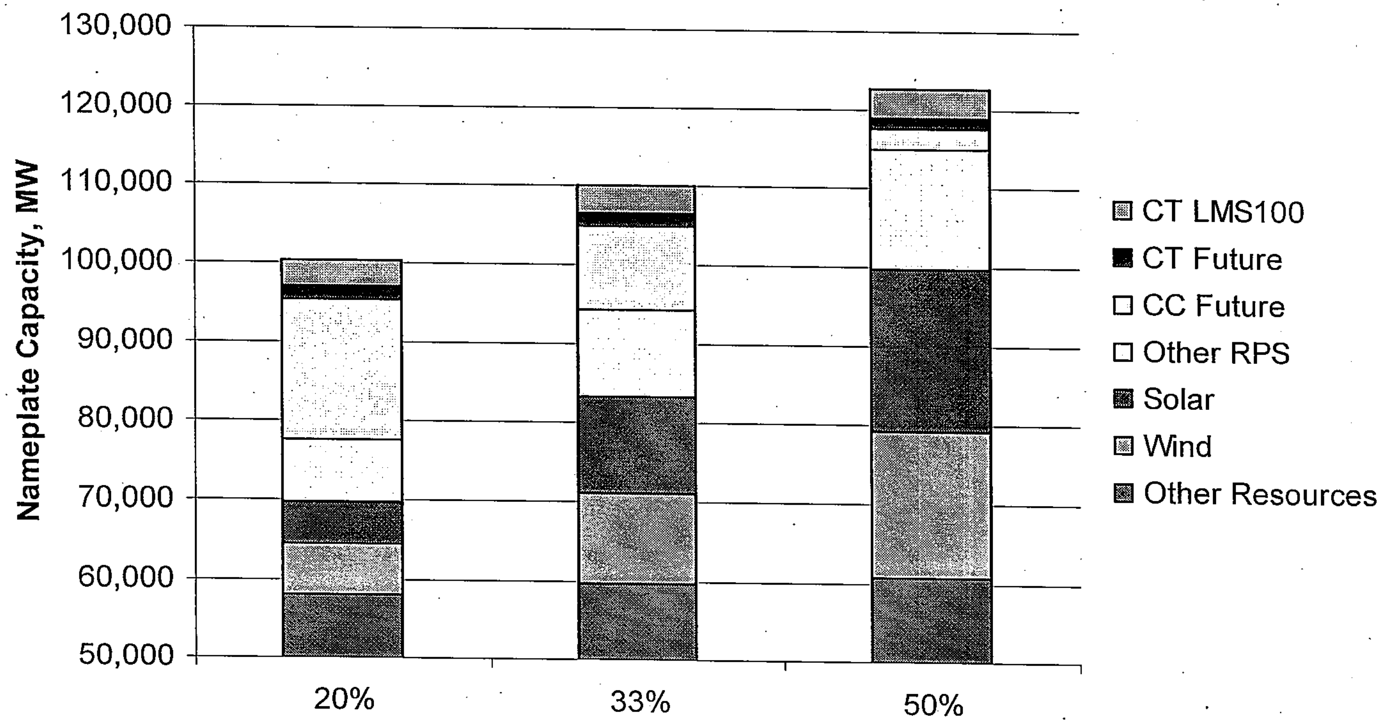
Generation Expansion Assumptions

- Developed generation plans for CA utilities based on these criteria:
  - Expansion used known planned projects as much as possible
  - An 18% planning reserve margin
  - The appropriate level of RPS requirements
  - Resolution of any operational violations found in production modeling (sometimes required adding peakers)
  - Developed plans for four study years (2012, 2016, 2020, 2025) for California and the rest of the WECC
- Developed "economically reasonable," but not optimal expansion plans
  - Often guided more by RPS requirements than by "Least Cost Best Fit" parameters
- Determined annual fixed costs for added plants
  - For renewables, all costs are fixed
  - Fossil fixed costs include capital-related and fixed O&M

Generation Expansion Assumptions (cont'd)

- The 20% RPS case was the base case starting in 2012
- All known, contracted, or other specifically planned California renewable projects scheduled for operation by 2012 were assumed to be built
  - In order to meet the 20% RPS targets roughly equal amounts of wind and solar generic generation were added
  - Out-of-state RPS and non-RPS generation owned by or with rights held by California utilities was delivered over existing interties
  - The planned generation for non-California WECC entities in the Transmission Expansion Planning Policy Committee (TEPPC) database established the base 2012 generation plan and additional wind and solar resources were added to meet the RPS target
- All generating plants that appeared in the 20% base case appeared in all other cases, except for specific fossil retirements

Resource Plans, 2025



- Other RPS includes biomass, geothermal, small hydro, out-of-state renewables
- Other Resources includes Non-RPS imports

Generation Planning – RPS Targets

- RPS Targets by technology were established for California only

- For non-CA WECC states, roughly equal amounts of wind and solar were added WECC-wide to meet RPS targets, but not in each state

- The 2012 the California renewable energy mix was:
  - Small hydro 5%
  - Biomass 14%
  - Geothermal 32%
  - Wind 31%
  - Solar 18%

- The types of incremental solar for future base cases were:
  - Solar thermal without storage (Solar CSP)
  - Solar thermal with storage (Solar TES)
  - Solar photovoltaic (solar PV)
  - Concentrating solar photovoltaic (solar CPV)

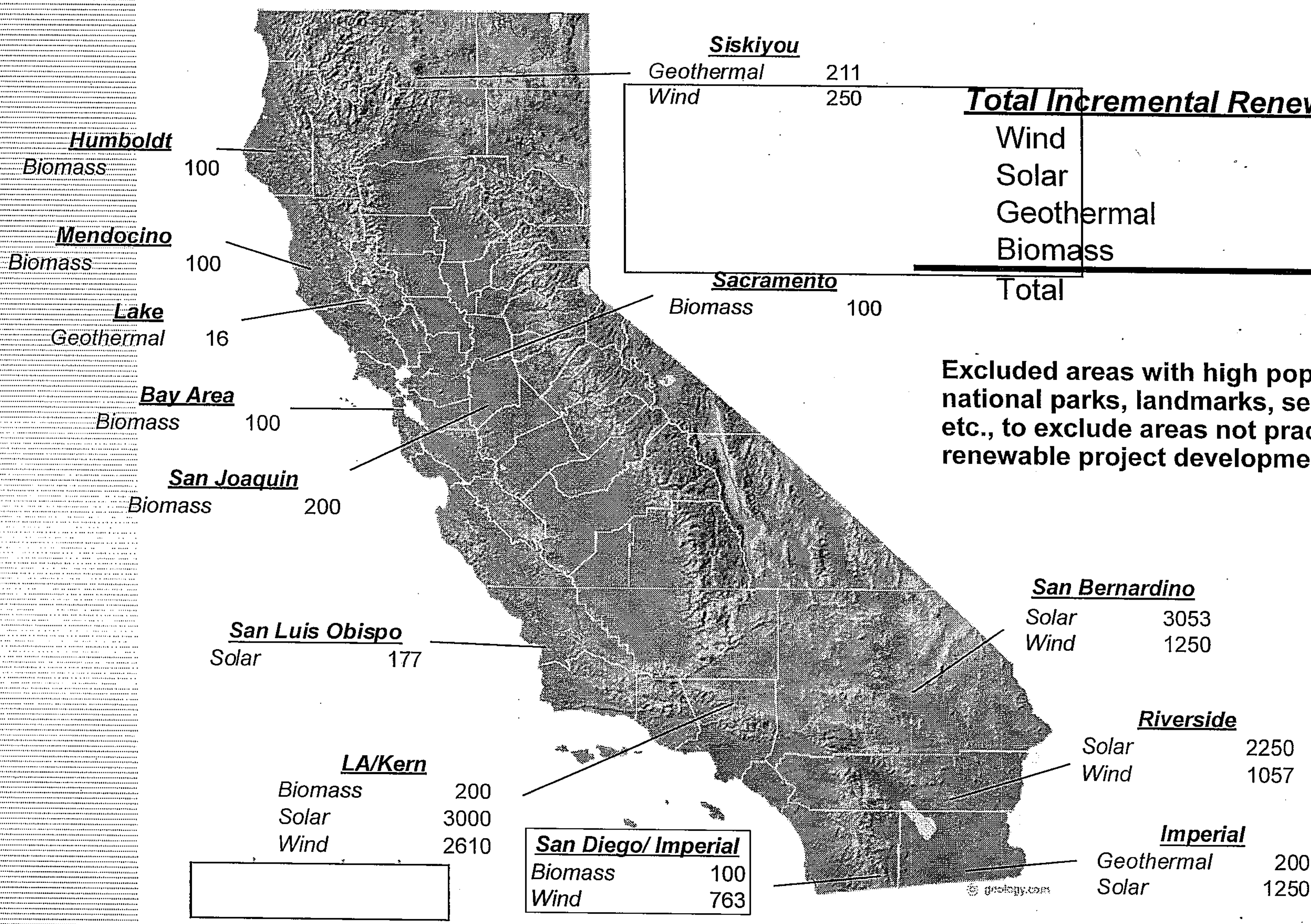
Generation Planning – RPS Targets (cont'd)

- Renewable energy mix in the future 20% cases
  - Small hydro energy was held constant
  - The 2012 biomass and geothermal percentages were held constant
  - The remaining energy requirement was filled roughly equally with wind and solar
- Renewable energy mix in the 2020 33% case
  - Small hydro energy was the same as in 2012
  - 50% of the available potential of relatively low cost geothermal and biomass were assumed developed by 2020
  - The remaining energy requirement was then filled equally with wind and solar
- Existing and Planned generation
  - Information available on the CEC, CPUC, SMUD and LADWP websites was used for adding future renewable and non-renewable generation in other areas

WECC - RPS Assumptions

	Year			
Region	2012	2016	2020	2025
Alberta	10.0%	12.8%	15.5%	17.5%
Arizona	10.0%	12.8%	13.2%	15.0%
British Columbia	10.0%	12.8%	13.4%	15.0%
California	N/A	N/A	N/A	N/A
Colorado	10.0%	12.8%	15.6%	17.5%
Montana	10.5%	11.6%	12.2%	15.0%
Nevada	10.0%	15.0%	20.0%	20.0%
North Baja California	0.0%	0.0%	0.0%	0.0%
New Mexico	8.0%	11.9%	15.8%	17.5%
North West	10.0%	12.2%	14.4%	17.5%
Idaho	5.0%	5.0%	5.0%	7.5%
Utah	5.0%	10.0%	15.0%	20.0%
Wyoming - Central East	5.0%	5.0%	5.0%	7.5%
WECC Total	9.3%	12.0%	14.2%	16.4%

Incremental Renewables 40% RPS, 2020

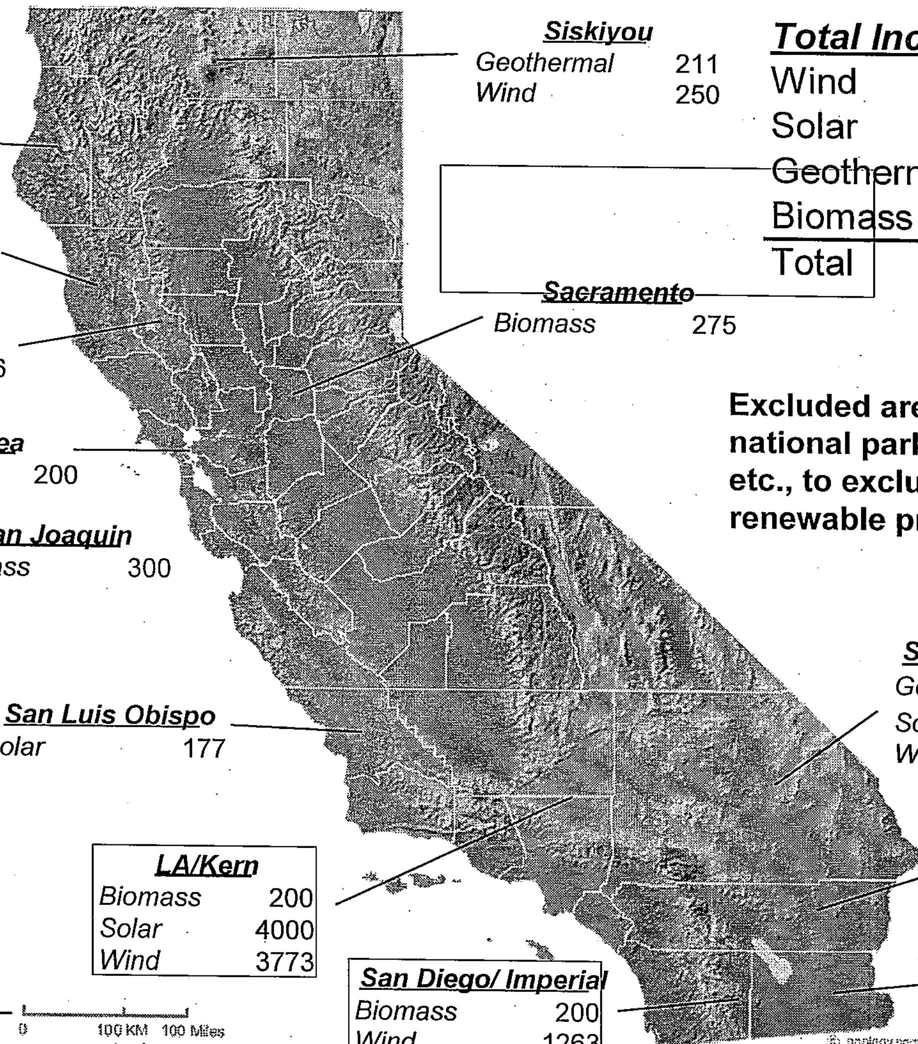


Total Incremental Renewables (MW)	
Wind	5,930
Solar	9,730
Geothermal	427
Biomass	900
Total	16,987

Excluded areas with high population density, national parks, landmarks, sensitive areas, etc., to exclude areas not practical for renewable project development

* Incremental to 20% RPS case in 2020

Incremental Renewables 50% RPS, 2025



Total Incremental Renewables (MW)	
Wind	9,093
Solar	15,480
Geothermal	775
Biomass	1,475
Total	26,823

Excluded areas with high population density, national parks, landmarks, sensitive areas, etc., to exclude areas not practical for renewable project development

* Incremental to 20% RPS case in 2020

Base Case – Capacity Summary

Case Name		**20%**	**33%**	**40%**
Year	**2007**	**2020**	**2020**	**2020**
CA peak Demand, MW		72,862	72,862	72,862
Firm capacity, MW		82,600	82,689	82,744
Additional Firm over interties, MW		3,436	3,436	3,436
Total Firm Capacity, MW		86,036	86,124	86,180
CA Reserve Margin		**18.1%**	**18.2%**	**18.3%**
Nameplate Capacity, MW				
Wind	1,693	5,452	11,325	13,282
Solar	484	5,078	11,808	14,808
Geothermal	1,903	2,652	2,787	3,079
Biomass	1,050	1,393	1,693	2,293
Small Hydro	637	640	640	**640**
Total RPS	**5,766**	**15,215**	**28,253**	**34,202**
Future non-RPS (CC, CT, LMS100)	701	14,306	11,329	7,863
Other non-RPS, MW	62,275	61,026	57,078	56,902
Total non-RPS, MW	62,976	75,332	68,407	64,765
Total Out-of-State RPS (incl. in other total non-RPS)	0	2,026	3,776	4,776

CA RPS Energy Summary

Case Name		20%	33%	40%
Year	**2007**	**2020**	**2020**	**2020**
Previous Year CA Energy Delivered, GWH		287,941	313,684	313,684
20% RPS target		62,737		
33% RPS Target			103,516	
40% RPS Target				125,474
CA RPS Energy by type, GWH				
Wind	4,703	18,027	36,916	44,603
Solar	1,759	12,309	31,199	39,937
Geothermal	13,234	20,769	21,715	23,761
Biomass	6,758	9,200	11,039	14,718
Small Hydro	2,605	2,612	2,612	2,612
Total RPS	**29,058**	**62,916**	**103,480**	**125,631**
CA RPS %		**20.06%**	**32.99%**	**40.05%**

Transmission Upgrades - 33% RPS Case 2020

Identified Upgrades in the 33% RPS Case - 2020	
1	A new 500/230 kV Substation at Kramer with one 500 kV line to Lugo, and two 1120 MVA 500/230 kV Transformers to connect renewables from north of Kramer.
2	Add two 1120 MVA 500/230 kV transformers at Midpoint to interconnect renewables
3	Add two 1120 MVA 500/230 kV transformers at Pisgah to interconnect renewables.
4	Increase the Julian Hinds-Mirage 230 kV transfer capability by reconductoring
5	Increase transfer capability between Coachella and Devers by adding two 230 kV lines
6	Add one 1120 MVA, 500/230 kV transformer at Vincent to relive the existing transformer overload due to additional renewables
7	Central California Clean Energy Transmission Project (C3ETP) to import renewables into northern CA
8	Northern California transmission project capable of delivering 1,000 MW of renewable generation from Northwest

Transmission Expansion – Assumptions

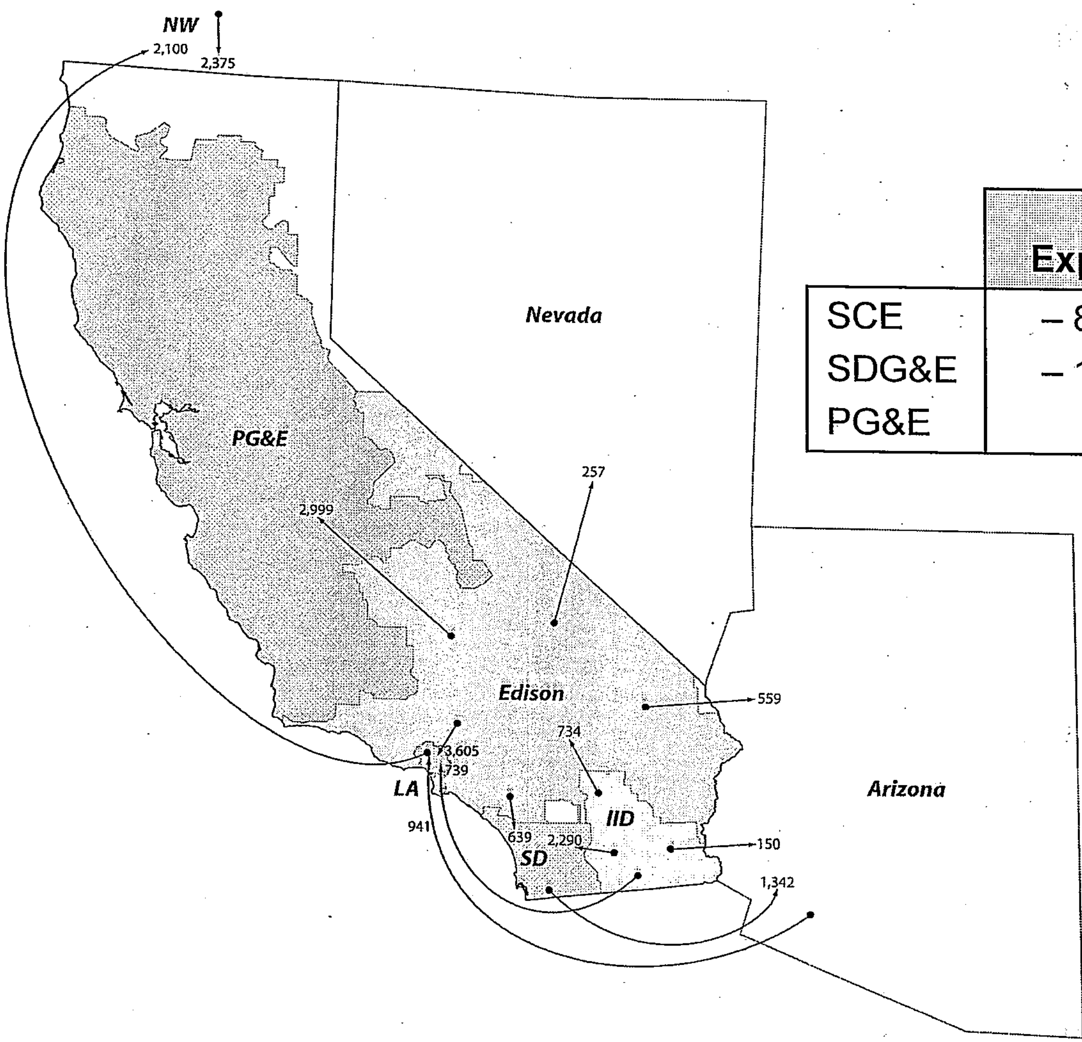
- Transmission expansion included estimates for:
  - Generation-ties
  - Collection Systems
  - Bulk transmission network requirements
  - Tie-line upgrades
- Generation-Ties were sized for nameplate generator output
- Collection systems were sized to handle loading from renewable resources
- Bulk transmission network upgrades were based on production simulation output for the 2025 50% RPS scenario
- Bulk transmission network upgrades, for other base cases, are based on Nexant professional judgment, resource plans, and power flow results from the 50% RPS case

Transmission Expansion – Collector system

- The collector systems was designed considering the diversity of the wind and solar production profiles.
- The design assumed that it may be cost effective to curtail some renewable generation from time-to-time to reduce the need for additional transmission.
- Savings in transmission costs were based on the fact that more nameplate capacity can be accommodated by the same transmission.
- The above concept may require additional protection and control to reliably operate the grid.

Results – One Hour Net Interchange

- Interchanges between regions in 2025, 50% case, California Exports, with Solar plants having 6 hours of storage
  - April 14 Hour 10



Megawatts

	Exports	Imports	Net Interchange
SCE	– 8,059	734	– 7,325
SDG&E	– 1,342	2,929	1,587
PG&E	– 0	5,374	5,374

Planning Reserves and Resource Counting Assumptions

- Started with a constant 18% planning reserve margin (PRM) for CA for 33% RPS
  - Slightly higher than 15-17% level currently being used
- Reached a 21% PRM for CA for 50% RPS
- Renewables were assigned the following "firm capacity multipliers" for the purpose of calculating the PRM:
  - Wind, 10%
  - Solar PV and CPV, 45%
  - Solar thermal, 56%
  - Solar thermal with storage, 95%

Nexant Generation Technology and Costs

Technology	Capacity Factor, %	$/kW		Nominal $, Incl Gen Tie		
				$/kW-yr		$/MWH
		Incl Gen Tie	Gen Tie Only	Total	Fixed Only	Total
Wind 30% CF	30.0%	1,739	139	290		110
Wind 35% CF	35.0%	1,739	139	292		95
Wind 40% CF	40.0%	1,739	139	295		84
PV	26.4%	6,000	40	447		193
CPV	27.0%	6,780	40	506		214
Solar Trough	25.0%	3,240	40	358		163
Solar Trough 6 hr Storage	34.5%	4,389	40	527		174
Solar CR 3 hr Storage	29.0%	3,140	40	483		190
Solar CR 6 hr Storage	37.0%	3,765	40	565		174
Geothermal	80.0%	2,460	60	539		77
Biomass	70.0%	4,057	57	724		118
Combined Cycle	N/A	1,074	24		99	
Std Peaking	N/A	628	28		55	
LMS 100	N/A	1,024	24		88	

(developed and used by Nexant in the study)