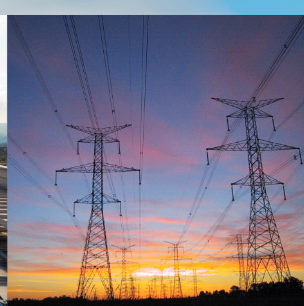
California Public Utilities Commission



33% RENEWABLES PORTFOLIO STANDARD
Implementation Analysis Preliminary Results

June 2009

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SUSAN LEE – Aspen Environmental Group
SIMON EILIF BAKER – CPUC

Acknowledgements

This report is the product of collaboration between the California Public Utilities Commission (CPUC) Energy Division staff and a team of consultants. The CPUC Project Lead was Paul Douglas, and the Project Manager was Elizabeth Stoltzfus. The CPUC team also included Anne Gillette, Jaclyn Marks, and Simon Baker. We would like to emphasize that the views and analyses expressed in this report are not the views of the CPUC, but rather the contributors to this report.

We are grateful for the technical analysis and expertise that the consultants provided to this effort. In particular, we would like to thank Arne Olsen, Ren Orans, Snuller Price, Amber Mahone, and Doug Allen from Energy Environmental Economics, Inc., and Carl Linvill, Susan Lee, and Brewster Birdsall of Aspen Environmental Group, the primary consultant study team. We would also like to thank Eric Toolson and Wenxiong Huang from PLEXOS Solutions, LLC., and Tim Mason, Ryan Pletka, and Derek Djeu from Black and Veatch.

In addition to the consulting team, we would like to thank Gary DeShazo, Grant Rosenblum, and Judith Sanders from the California Independent System Operator for their technical input throughout the analysis and for their future contribution to Phase 3 of this analysis.

The staff at the CPUC contributed significantly to validating the technical analysis as well as reading through various drafts of this report. We are especially grateful to our management, Julie Fitch and Nancy Ryan for their continued guidance and support in helping to craft this report. We would also like to thank Dan Hartmann and Amy Baker for the graphics, and Simon Baker for supporting this effort since its inception a year ago. Our report also benefited from careful editing and review from other colleagues at the CPUC, including Kristin Ralff-Douglas, Keith White, Pete Skala, Molly Sterkel, Billie Blanchard, Chloe Lukins, Burt Mattson, Anne Simon, Victoria Kolakowski, Janet Econome, Peter Allen, Sara Kamins, and Iain Fisher. We would also like to thank Terrie Prosper for copy editing this report.

Lastly, we would like to thank the participants of the 33% RPS Implementation Analysis Working Group and the Transmission Constrained Working Group in the long-term procurement plans proceeding who provided their technical expertise through attending workshops, working group meetings, conference calls, and technical comments.

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1 Executive Summary

California lawmakers are currently developing legislation to increase the current 20% by 2010 Renewables Portfolio Standard (RPS) to 33% by 2020. The California Public Utilities Commission (CPUC) and California Energy Commission (Energy Commission) have endorsed this change and it is a key greenhouse gas (GHG) reduction strategy in the California Air Resources Board's (ARB) Assembly Bill (AB) 32 Scoping Plan. As the principal agency responsible for implementing the current RPS program, the CPUC has learned many lessons that can help guide the design of a higher mandate. In addition, several recent analyses have cast light on various aspects of renewable energy development and integration. Drawing on these resources and new analyses, staff at the CPUC developed this report in order to provide new, in-depth analysis on the cost, risk, and timing of meeting a 33% RPS. This report does not recommend a preferred strategy on how to reach a 33% RPS, but rather provides an analytical framework for policymakers to weigh the tradeoffs inherent in any future 33% RPS program for California.

Summary of key findings include:

- **Timeline:** Achieving 33% RPS by the year 2020 is highly ambitious, given the magnitude of the infrastructure buildout required.
- **Resources:** To meet the current 20% RPS by 2010 target, four major new transmission lines are needed at a cost of $4 billion. Three of these lines are already underway. To meet a 33% RPS by 2020 target, seven additional lines at a cost of $12 billion would be required. In addition, the 33% RPS target is projected to require almost a tripling of renewable electricity, from 27 terawatt hours (TWh) today to approximately 75 TWh in 2020.
- **Cost:** Electricity will be higher in 2020 regardless of the RPS requirements.
    - o Even if California makes no further investments in renewable energy, this analysis projects that average electricity costs per kilowatt-hour will rise by 16.7% in 2020 compared to 2008 in real terms.
    - o In 2020, the total statewide electricity expenditures of achieving a 20% RPS are projected to be 2.8% higher compared to a hypothetical all-gas scenario, where new electricity needs are met entirely with natural gas generation.
    - o In 2020, the total statewide electricity expenditures of achieving a 33% RPS utilizing the current procurement strategy is projected to be 7.1% higher compared to the 20% RPS, and 10.2% higher compared to an all-gas scenario.
- **Policies:** Achieving a 33% RPS by 2020 requires tradeoffs amongst various policy goals and objectives. If the 2020 timeline is the most important policy priority, California must start implementing mitigation strategies such as planning for more transmission and generation than is needed to reach just 33%, pursuing procurement that is not dependent on new transmission, or concentrating renewable development in pre-permitted land that would be set aside for a renewable energy park.

APPROACH

Four Unique Renewable Resource Cases Created for Analysis

In order to conduct the implementation analysis, four unique renewable resource cases were developed. Each case represents a different 33% RPS procurement strategy to reaching the 33% RPS target. All cases assume current statutorily defined out-of-state deliverability requirements for renewables into California. Thus, these cases cannot be used to analyze the option of allowing out-of-state tradable renewable energy credits (REC) with no delivery requirement for RPS compliance.

- **33% RPS Reference Case:** This case represents California's current renewable procurement path, which is heavily dependent on new technologies, such as central station solar thermal.
- **High Wind Case:** This case demonstrates less reliance on in-state solar thermal and more reliance on less expensive wind resources in California and the Mexican state of Baja California.
- **High Out-of-State Delivered Case:** This case relies on construction of new, long-line, multi-state transmission to allow California utilities to procure large quantities of low-cost wind and geothermal resources from other western states (as noted above, this case does not include the use of tradable RECs with no delivery requirement).
- **High Distributed Generation (DG) Case:** This case assumes limited new transmission corridors can be developed to access additional renewable resources needed to achieve a 33% RPS. Instead, extensive, smaller-scale, renewable generation is interconnected to the distribution system or close to transmission substations.

In addition, a **20% RPS Reference Case** was developed to serve as a benchmark for cost comparisons between the cost of the current 20% RPS program and a 33% RPS in 2020. This reference case is comprised of California's likely renewable energy mix in 2020 based upon current state law and existing RPS contracts. As such, this case provides the most relevant benchmark against which to measure the incremental cost of various paths to meeting the higher 33% RPS target.

Two additional scenarios were developed to provide further points of reference:

- **All-Gas Scenario:** This scenario represents the resource mix in 2020 if no additional renewables were developed beyond 2007, and the rest of California's electricity needs were met with gas-fired generation. It supports comparisons between the cost of continuing investments in mostly natural gas and implementing a 33% RPS in 2020.
- **2008 Costs:** This scenario represents the current cost of electricity in California. It supports comparisons across the 2020 scenarios of increases relative to today's costs.

The report uses the four different possible 33% RPS cases to assess the costs and tradeoffs of each approach. It should be noted that:

- Projected costs are based on renewable technology costs and not the contract prices.
- The cost analysis assumes current technology costs, and makes no assumptions about the cost trajectory (up or down) of particular technologies over time due to potential transformation of the market.
- Average electricity costs per kilowatt hour are expressed as statewide averages and are not indicative of individual utilities' rates or the actual bills that consumers will pay.

Three Illustrative Timelines Created for Analysis

This report then uses the 33% RPS Reference Case to construct three illustrative timelines for achieving a 33% RPS. These timelines demonstrate how and when the state could plausibly build the necessary renewable generation and transmission to reach a 33% RPS. The timelines also offer insights into the increased need for public and private sector resources in order to quickly process the increased number of transmission and generation applications over the next 10 years.

- **Illustrative Timeline 1: Historical experience without process reform**

  This scenario is based on the state's experience with generation and transmission development over the last 10-15 years. The timeline assumes transmission planning, permitting, and construction processes that are almost entirely sequential.

- **Illustrative Timeline 2A: Current practice with process reform and no external risks**

  This scenario represents the development trajectory if California successfully implements transmission and generation process reforms that are already underway. Although not plausible since it does not include external risks that are beyond the state's control, this timeline serves to isolate the effect of the process reforms, and is the reference point that Timeline 2B is built upon.

- **Illustrative Timeline 2B: Current practice with process reform and external risks**

  This scenario represents the development trajectory if California successfully implements process reforms, but includes negative impacts and delays from external risks outside the direct control of state agencies, such as emerging technology risk, financing difficulties, and public opposition or legal challenges.

FINDINGS

Key Findings from Timeline Analysis:

The report finds that a 33% RPS in 2020 is highly ambitious, given the magnitude of the infrastructure buildout required

The magnitude of the infrastructure that California will have to plan, permit, procure, develop, and integrate in the next ten years is immense and unprecedented. This goal is more attainable with a commitment of significant new staff resources in both the public and private sectors. The conclusions below are based on an implementation analysis of the 33% RPS Reference Case.

- Timeline 1 reaches a 33% RPS in 2024. Using past practices as a guide, the scale of the transmission and generation buildout will take at least 14 years if implementation starts today. This timeline, however, assumes no external risks.
- Timeline 2A reaches a 33% RPS in 2021. This timeline assumes successful implementation of numerous process reforms now underway, which speed achievement of the 33% RPS from 2024 to 2021. This timeline represents a best case scenario as it assumes no external risks, no resource constraints in processing numerous transmission and generation applications, and that the California ISO is able to successfully implement its planned new process to review and approve more than one major transmission application per year.
- Timeline 2B does not reach the 33% RPS since two resource zones fail to develop due to risks outside of the state's control.

Numerous external risks could undermine the time savings achieved by process reforms

Several factors outside direct state control could undermine the gains realized through the various reform initiatives. These external risks could delay attainment of the 33% RPS target well beyond 2020, especially if California continues on its current renewable resource contracting path.

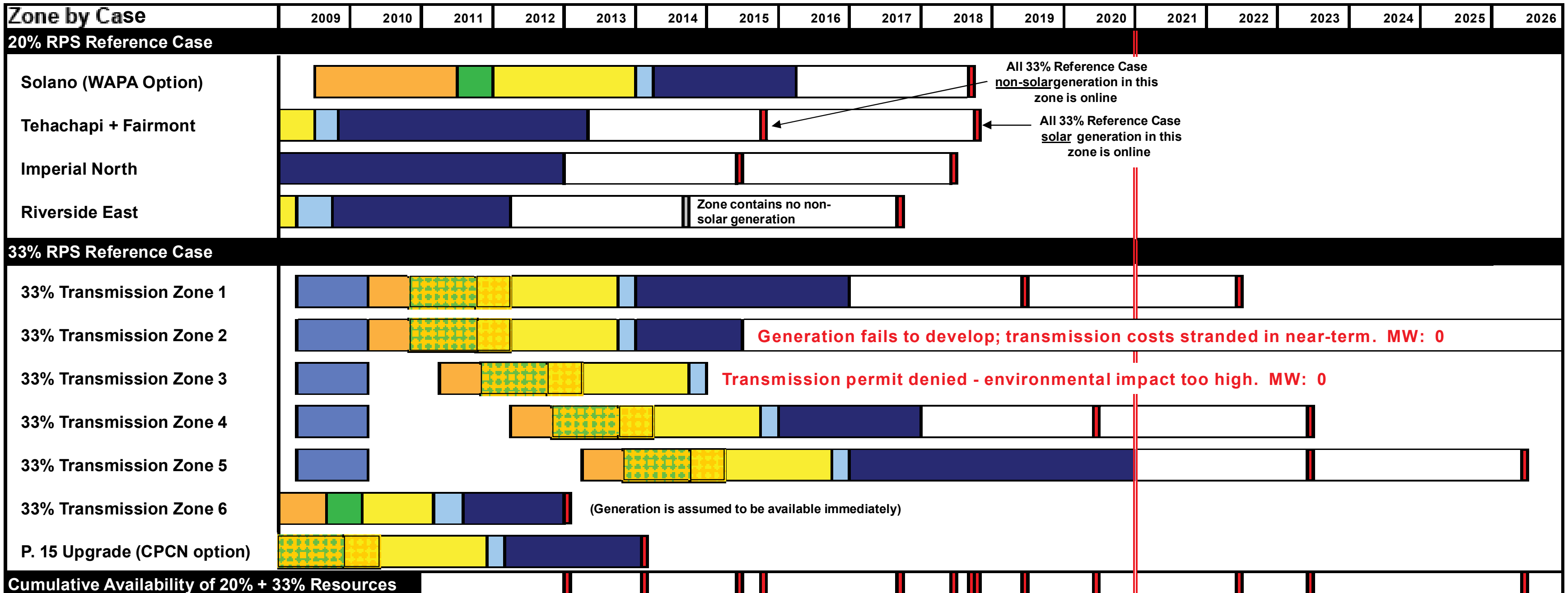
- Timeline 2B (see Exhibit A) illustrates how unanticipated contingencies could affect the timing of reaching the 33% RPS goal. External risks delaying this timeline include:
    - California's high reliance on relatively new technologies and companies
    - Scale of new infrastructure investment, which this analysis estimates at approximately $115 billion between now and 2020, in an uncertain financial environment
    - Environmental impacts of generation and transmission facilities that may require the use of large areas of undeveloped and perhaps pristine land
    - Legal challenges and public opposition to large-scale renewable energy infrastructure

California must start implementing mitigation strategies if achieving a 33% RPS by the year 2020 is the most important policy priority

Timeline 2B provides an example of a scenario in which, despite successful implementation of ambitious reforms, two resource zones fail to develop due to external risks. While Timeline 2B presents a hypothetical example, it illustrates the potential impact of real risks that California's current procurement strategy is not prepared to mitigate. Specifically, California's current procurement path is focused almost solely on central station renewable generation that is dependent on new transmission. In order to mitigate the risk that one resource zone would fail to develop, thereby delaying the achievement of a 33% RPS by several years, the state should consider a procurement strategy that adequately considers the time and risk, in addition to price, associated with particular renewable generation resources. The state may also wish to adopt risk mitigation strategies, such as:

- Planning for more transmission and generation than needed to reach just 33%
- Pursuing procurement, such as distributed solar photovoltaics (PV), which is not dependent on new transmission
- Concentrating renewable development in pre-permitted land that would be set aside for a renewable energy park

Exhibit A. Illustrative Timeline 2B for the 33% RPS Reference Case: Current Practice With Process Reform and External Risks



MW available per year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Biomass							74	74	74	74	165	165	165	165	165	165	165	165
Geothermal							1,120	1,120	1,120	1,120	1,120	1,144	1,144	1,144	1,144	1,144	1,144	1,144
Solar thermal + PV									1,349	2,008	2,008	2,008	2,008	4,556	5,979	5,979	5,979	6,724
Wind					100	100	4,397	4,397	4,397	5,397	6,208	6,411	6,411	6,411	6,866	6,866	6,866	6,866
Total Zone Resources					100	100	5,591	5,591	6,940	8,599	9,501	9,728	9,728	12,276	14,154	14,154	14,154	14,899

CAISO Development of 33% Renewable Tansmission "Conceptual Master Plan"
Project-specific Transmission Planning by CAISO / POU / WECC
CPCN / Project Description Prep by Utility
CEQA/NEPA review by CPUC / POU / Feds
Final Project Review and Approval by CPUC / POU / Feds
Final Design + Construction by Utility
Gradual Generation Interconnection

Source: CPUC/Aspen

Result: The 33% RPS Reference Case is not achieved due to unexpected problems with the development of two zones and delays in deployment of large-scale solar projects. Regardless of the nature of the risks that may actually occur, realization of any risk could cause delay and have a significant impact on timing. Although the state does not have direct control over many of the risks facing renewable energy development, it could adopt strategies that would mitigate specific risks.

Key Findings from Renewable Resource and Cost Analysis

A 33% RPS is projected to require almost a tripling of renewable electricity, and nearly a doubling of new transmission lines

The 33% RPS Reference Case is projected to require an additional 75 TWh of renewable electricity, or nearly a tripling compared to the 27 TWh of delivered renewable electricity generated at the end of 2007. It is also projected to require seven new transmission lines to deliver the additional 75 TWh of electricity.

Exhibit B. Renewable Generation and Transmission Needed in 2020

20% RPS Reference Case would require	33% RPS Reference Case would require
35 TWh of new renewable electricity in 2020, in addition to **27 TWh** of generation from renewables in existence at the end of 2007	**75 TWh** of new renewable electricity in 2020, in addition to **27 TWh** of generation from renewables in existence at the end of 2007
4 New Major Transmission Lines at cost of **$4 Billion**	**7** Additional Major Transmission Lines at cost of **$12 Billion**

Electricity will be higher in 2020 regardless of the RPS requirements

Real electricity costs will be significantly higher in 2020 compared to 2008, regardless of whether California pursues a 20% or 33% RPS (see Exhibit B).

- Even if California makes no further investments in renewable energy (the all-gas scenario), the analysis projects that average statewide electricity costs per kilowatt hour will rise by 16.7% in 2020 compared to 2008 in real terms. This increase results from the need to maintain and replace aging transmission and distribution infrastructure, anticipated investments in advanced metering infrastructure and other smart grid capabilities, the cost of repowering or replacing generators to comply with once-through cooling regulations, and the cost of procuring new conventional generating resources to meet load growth.
- In 2020, the total statewide electricity expenditures of the 20% RPS Reference Case is projected to be 2.8% higher compared to the all-gas scenario.
- In 2020, the total statewide electricity expenditures of the 33% RPS Reference Case is projected to be 7.1% higher compared to the 20% Reference Case, and 10.2% higher compared to the all-gas scenario.

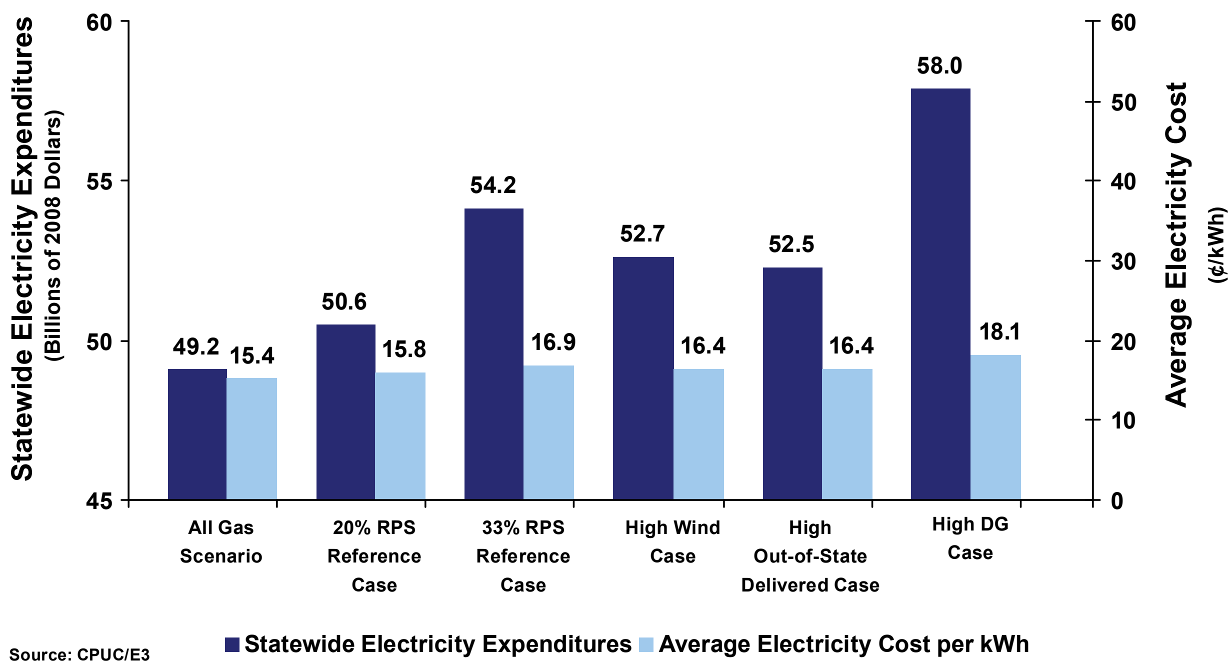
The 33% RPS Reference Case is the most expensive case relative to the alternative 33% RPS cases requiring new transmission lines; but it is still much less costly than the High DG Case (see Exhibit B)

The cost premium of meeting a 33% RPS does not vary greatly between the High Out-of-State Delivered Case and the High-Wind Case. Statewide electricity expenditures under these cases are $1.5 and $1.8 billion lower than the 33% RPS Reference Case, respectively, with the cost savings largely resulting from replacing large quantities of solar thermal resources with less costly wind resources.

The High DG Case adds almost twice the incremental costs of the 33% RPS Reference Case

The cost premium of the High DG Case is significantly higher than the 33% RPS alternative cases, with a 14.6% cost premium compared to the 20% RPS Reference Case, and a 7.0% cost premium compared to the 33% RPS Reference Case. This is due to the heavy reliance on solar PV resources, which are currently more expensive than wind and central station solar.

Exhibit C. Statewide Electricity Expenditures and Average Electricity Cost in 2020



Source: CPUC/E3

Findings from Sensitivity Analysis

Projecting the costs of different renewable and fossil-fired energy sources out to 2020 requires numerous assumptions about future conditions including load growth, equipment costs, and fuel prices. Many of these variables are highly uncertain, and some significantly influence the model's results. Accordingly, the study includes sensitivity analysis in three key areas, finding that:

- A 33% RPS can serve as a hedge against natural gas prices, but only under very high natural gas and GHG allowance prices. Thus, the hedging value in itself is not a very strong justification to do a 33% RPS.
- The interplay between energy efficiency achievement and renewable energy procurement highlights the need to analyze and plan for the interactions among the state's various policy goals. If the state does not plan for interactions, then a 33% RPS by 2020 could result in a surplus of energy or capacity and excess consumer costs.
- Dramatic cost reductions in solar PV could make a solar DG strategy cost-competitive with central station renewable generation. More analysis is necessary to determine the programmatic strategies necessary to achieve a high-DG scenario as well as the feasibility of high penetrations of solar PV on the distribution grid.

POLICY OBJECTIVES AND TRADEOFFS

Achieving a 33% RPS will require tradeoffs amongst various policy goals and objectives

There are multiple renewable procurement strategies that California could pursue to reach a 33% RPS, but each procurement path will reach the 33% RPS target on a different timeframe and will perform differently across the broad range of RPS policy objectives that stakeholders and decision-makers have articulated. See Exhibit D for a comparison of how each 33% RPS Case performs across the RPS policy objectives.

Exhibit D. Comparison of 33% RPS Cases Across RPS Policy Objectives

Policy Objective	33% RPS Reference Case	High Wind Case	High Out-of-State Delivered Case	High-DG Case
Cost	◒	●	●	○
Timing	○	◒	◒	◒
GHG Emission Reductions	●	●	●	●
Resource Diversity (Hedging Value)	●	●	●	●
Local Environmental Quality Air Quality	●	◒	○	●
Local Environmental Quality Land Use	○	◒	◒	●
In-state Economic Development	◒	◒	○	◒
Long-Term Transformation	●	○	○	●
Technology Development Risk	○	●	●	○

Legend:

● Case performs well ○ Case performs poorly ◒ Case is neutral

California IOUs are currently on a procurement path that in effect prioritizes long-term market transformation over other policy objectives. California's IOUs are depending on new renewable technologies, including solar thermal, to meet their RPS obligations. This procurement strategy may lead to long-term market transformation of the central station solar market, but due to risks inherent to new technologies, this strategy could result in higher prices and a longer development period that could delay achievement of a 33% RPS to after 2020.

RPS Policy Objectives Should Be Prioritized

As this analysis has shown, many of the policy objectives are mutually exclusive and in conflict with one another. Currently, the RPS procurement process is in effect dictating the timing, cost, and policy objectives of a future 33% RPS program. Thus, the tradeoffs are being decided through the utility procurement process, not by the policymakers or regulators. Using current RPS contracts as an example, market transformation and in-state economic development are the primary policy objectives that are being prioritized at the expense of meeting a 2020 timeline and minimizing customer costs. This results from lack of having a stated priority preference. Some of the key questions to help determine a priority preference include:

- Should California focus public investment and system planning efforts on developing and integrating technologies with significant long-term transformational potential such as solar thermal or solar PV?
- Should California focus on developing in-state resources? Up to what cost? What is the correct balance between in-state economic development and higher customer costs?
- Is California willing to delay the 2020 target in order to develop primarily California resources and stimulate new technologies and market transformation?
- Should California waive renewable energy delivery requirements for out-of-state resources if it is necessary to meet the 2020 target or pursue a lower cost strategy?
- Should the CPUC encourage the utilities to procure increased amounts of (currently) high-cost solar PV to mitigate the potential negative impact of delay due to failure of a resource zone?

NEXT STEPS

This report presents the preliminary results of the 33% RPS Implementation Analysis and does not include results from Phase 3, the final phase of this analysis. By the end of 2009, the final results will incorporate additional analyses. First, the California ISO will complete a study to determine the resource requirements to integrate the intermittent renewable resources needed for a 33% RPS. Second, the transmission cost estimates will be updated based on the latest information from the Renewable Energy Transmission Initiative (RETI) and the California ISO's conceptual transmission planning process. Finally, CPUC staff will identify and articulate solutions and strategies for addressing many of the risks and challenges identified throughout this report.

2 Introduction

The CPUC, in conjunction with the Energy Commission, is responsible for implementing the state's Renewables Portfolio Standard Program, which is one of the most ambitious renewable energy standards in the country. California lawmakers are contemplating increasing the current RPS mandate, which is 20% renewable energy by 2010, to 33% renewable energy by 2020. A 33% renewable goal could further California's efforts to address climate change and lead the nation in proactive clean energy policy. The CPUC supports this more aggressive 33% renewable energy standard and recommended it as a key electric sector strategy in the Energy Commission/CPUC joint recommendations to the California Air Resources Board to help California meet its climate change targets established in AB 32, the Global Warming Solutions Act of 2006. The ARB adopted this recommendation in December 2008. [1]

The CPUC's Energy Division staff initiated this study in August 2008 in order to provide a quantitative analysis of the costs and risks of alternative means of achieving a 33% RPS by 2020.[2] The report seeks to answer two key questions: 1) How much will it cost to meet a 33% RPS, and 2) how will the state reach a 33% RPS by 2020? Working with a broad stakeholder group, including the investor-owned electrical utilities, industry experts, ratepayer advocates, and environmental groups, the study team, which consisted of CPUC staff and a consulting team, developed the preliminary results presented in this report. The report analyzes four different possible 33% RPS alternatives and articulates the costs and tradeoffs of each approach. The study team used the 33% RPS Reference Case to construct three illustrative timelines for achieving a 33% RPS. These timelines demonstrate how and when the state could plausibly build the necessary renewable generation and transmission to reach a 33% RPS. CPUC staff will issue a final report by the end of 2009, which will be informed by additional analysis that the California ISO is conducting.

POLICY GOALS AND OBJECTIVES

California has been leading the country with aggressive renewable energy targets since the establishment of the RPS in 2002. Senate Bill (SB) 1078 established Public Utilities Code Section 399.11 - 399.15, which created California's first RPS law and mandated a 20% RPS by 2017.[3] Just three years later, in 2005, the legislature amended the statute to accelerate this goal to 20% by 2010.[4] Current statute expressly prohibits the CPUC from requiring an RPS level beyond the 20% target.

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[1] California Air Resources Board, "Climate Change Scoping Plan," Approved December 11, 2008. Available at: http://www.arb.ca.gov/cc/scopingplan/document/scopingplandocument.htm.

[2] CPUC Decision (D.)07-12-052, which authorized the 2007 long-term procurement plans (LTPPs), directed Energy Division staff to work with stakeholders to refine a methodology for evaluating a 33% RPS by 2020 within the context of LTPP.

[3] Senate Bill 1078 (2002), Section 3, Article 16, PU Code Section 399.11(a)(b)(c)

[4] Senate Bill 107 (2006)

In November 2008, Governor Schwarzenegger issued Executive Order S-14-08, requiring state agencies to establish the Renewable Energy Action Team to streamline the review of transmission and renewable generation projects as well as commit state agencies to work towards achieving 33% of retail sales from renewable energy by 2020.[5] The legislature is currently considering several different bills that would mandate a 33% RPS by 2020.

Through legislation and other measures, state policymakers have articulated various policy goals and objectives that a 33% RPS should address:

- **Greenhouse Gas Emission Reductions**. California can avoid significant GHG emissions by replacing one-third of the state's energy supply with renewable resources. As part of its strategy to reduce emissions to 1990 levels by 2020, ARB has estimated that a 33% RPS could reduce GHG emissions by 21.3 million metric tons of carbon dioxide equivalent ($MMTCO_2e$), satisfying nearly 12% of the total required GHG reductions.
- **Long-Term Market Transformation.** An aggressive RPS target should help to drive the energy technology transformations needed to lower costs, upgrade current infrastructure, and achieve long-term GHG reductions beyond 2020. Scientists estimate that deep cuts in global GHG emissions of 50% to 85% below current levels by 2050 are necessary to prevent the worst impacts from climate change.[6]
- **Resource Diversity.** Higher levels of renewable energy generation can improve the diversity and security of California's energy supply, provide hedging value, and reduce dependence on fossil fuels with volatile prices, particularly natural gas.
- **Local Environmental Quality and Public Health.** Renewable generation can improve local air quality and public health, principally through reduced emissions of criteria pollutants at gas-fired power plants in California.
- **Economic Development.** Renewable technologies can create local manufacturing, installation, maintenance, and operational jobs.
- **Least-Cost, Best Fit.** Public Utilities Code Section 399.14 requires a renewable project selection process called "least-cost, best-fit," which allows the utility to select the project based on the value to the ratepayer and the utility. The statute requires the CPUC to consider estimates of indirect costs associated with the project, including new transmission investments and ongoing utility expenses resulting from integrating and operating renewable energy resources. Consequently, this report describes both the cost and "fit" attributes of four different portfolios of renewable resources.
- **Timing**. Since the ARB has linked a 33% RPS to the 2020 climate change goals, the speed at which renewable resources can be developed and integrated into the power grid is very important.

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[5] California Governor's Executive Order S-14-08, "Governor Schwarzenegger Advances State's Renewable Energy Development," November 17, 2008. Available at: http://gov.ca.gov/press-release/11073/.

[6] Intergovernmental Panel on Climate Change, "Climate Change 2007: Synthesis Report," 2007, Section 5.4, pg. 66-67, Assessment of the Intergovernmental Panel on Climate Change, Valencia, Spain. California Governor Schwarzenegger committed California to reduce statewide GHG emissions to 80% below 1990 levels by 2050 in Executive Order S-3-05, June 1, 2005. Available at: http://gov.ca.gov/executive-order/1861/.

STUDY OVERVIEW

Several other studies and processes have examined, or are now examining, a particular aspect of a California 33% RPS. Some of these studies have occurred in the past, while others are occurring in parallel with this analysis. These studies include:

- Center for Resource Solutions report prepared for the CPUC (2005)[7]
- E3's modeling work to develop the GHG Calculator in support of the joint CPUC/Energy Commission proceeding to develop recommendations for the ARB on implementation of AB 32 for the electricity sector[8]
- California ISO Preliminary Report on Renewable Transmission Plans (2008)[9]
- California ISO's Integration of Renewable Resources Program[10] to evaluate the generation performance characteristics and gas-fired generation needed to support increased levels of various types of renewable resources
- Energy Commission 2009 Integrated Energy Policy Report (IEPR) proceeding
- Ongoing work of RETI and other transmission planning processes to facilitate the interconnection of renewable generators

This study provides a more in-depth, granular, and comprehensive analysis of different possible renewable scenarios compared to these previous studies. It draws heavily on most of the sources described above for data and assumptions, including RETI and the GHG Calculator, both of which were scrutinized and evaluated through stakeholder processes. The analysis also used a stakeholder working group to vet and refine the study methodology, assumptions, and inputs, especially when the assumptions differed from existing studies. For example, the renewable technology cost numbers from RETI were used, except the financing assumptions were modified to incorporate recent changes in financial markets. This report also incorporates new resource potential identified in RETI and other sources, existing resources from the Western Electricity Coordinating Council's (WECC) most recent west-wide study cases,[11] and proposed projects under development (identified through utility procurement solicitations). As a result, the renewable energy project and cost data underlying this analysis is the best publicly available data to date.

In addition, this study is the first effort to create comprehensive generation and transmission timelines that illustrate the many steps required to bring renewable energy projects in California from conception to commercial operation. This study elevates the analysis from a general discussion of perceived barriers into illustrative timelines that depict the magnitude of the coordination challenge associated with a 33% RPS.

[7] http://www.resource-solutions.org/lib/librarypdfs/Achieving_33_Percent_RPS_Report.pdf
[8] http://www.ethree.com/CPUC_GHG_Model.html
[9] http://www.caiso.com/2007/2007d75567610.pdf
[10] See http://www.caiso.com/1c51/1c51c7946a480.html for status and documents related to this program.
[11] The analysis is built off of the November 2008 version of the WECC's Transmission Expansion Planning and Policy Committee (TEPPC) 2017 database.

Assumptions

Like any modeling effort, this study makes a number of simplifications in order to represent a complex problem in manageable proportions. Likewise, the analysis includes assumptions about the future that are not known today. First, this study is a statewide analysis, and not limited to the investor-owned utilities (IOUs). Second, this analysis used high-level estimates of renewable integration and transmission costs, which will be updated in the next phase of this study. Third, the technology costs presented in this analysis reflect the costs to build and operate the renewable project with a reasonable profit, but are not based on actual contract prices. Many of the other assumptions are stated below or are explained in the relevant sections throughout the report and in the methodology discussion found in Appendix B.

Study Outputs

This report presents the preliminary results of the first two phases of this three-phase study. The key outputs are described below.

Four Unique 33% RPS Cases

The study team developed four unique 33% RPS cases, or renewable resource portfolios, for achieving a 33% RPS by 2020. Each case addresses a different possible scenario. For example, the 33% RPS Reference Case reflects California's current renewable procurement path, which is focused partly on new technologies, such as central station solar. Three alternative 33% RPS cases were developed, which test the costs and benefits of a particular resource strategy, including higher levels of wind energy, out-of-state resources, and distributed renewable resources.

Renewable Resource Portfolio

A resource portfolio is a collection of renewable resources by quantity and technology type selected based on different constraints or policy objectives.

A fifth case was developed, termed the 20% RPS Reference Case, to serve as a point of comparison for any cost changes associated with a 33% RPS. The 20% RPS Reference Case reflects current state law and utility procurement. Two additional scenarios were developed to provide further points of reference: an all-gas scenario, which represents the resource mix in 2020 if no additional renewables were developed beyond 2007, and the rest of California's electricity needs were met with gas-fired generation, and 2008 Costs, which represents the current cost of electricity in California.

Estimates of Renewable Generation and Transmission

This report presents plausible estimates of the type and amount of renewable generation and transmission needed to reach a 33% RPS. The Energy Commission's 2007 IEPR load forecast was used to project electricity sales to 2020. The study team calculated the quantity of new renewable resources needed to meet the 33% RPS and then selected renewable resources to fill this need. The study also provides a high-level estimate of the new transmission investment needed to integrate and deliver renewable resources to load centers. However, the study did not undertake a detailed engineering analysis of the ability of the renewable resources to connect to the existing grid. It also does not reflect the conceptual transmission plans that RETI is currently developing, since these were not available at the time of this analysis. As a result, the transmission investment assumed in the cases does not represent an "optimal" or least-cost transmission plan. The study team will update the transmission results in the final phase of this study based on the transmission conceptual plans that RETI and the California ISO are developing.

Electricity Costs in 2020

All electricity costs are presented in 2008 dollars unless noted otherwise. This analysis calculated statewide electricity expenditures, which is an economic cost, for the different RPS cases in the year 2020, as well as the average cost per kWh in 2020. All costs include federal production and investment tax credits and state property tax incentives. This analysis did not calculate ratepayer bill impacts, which depend on policy design, cost allocation, and how economic costs are recovered through different rate classes. In addition, this analysis employed simplified assumptions for transmission costs and integration costs in lieu of detailed California ISO analysis. These cost assumptions will be updated in the final report following further analysis.

To estimate the cost of constructing new renewable resources, the study team relied primarily on data developed for the state's RETI process. RETI developed cost and performance information for hundreds of potential projects throughout California, representing tens of thousands of megawatts of renewable energy resources. Additional resource characterizations came from the GHG Calculator.

For most of the projects, the costs are the developer costs to build and operate the project with a reasonable profit. The project costs are not the negotiated contract prices. However, projects that were projected to cost less than a combined cycle gas turbine (CCGT) power plant were assumed to be at least as expensive as a CCGT, even if some renewable resources may be slightly less expensive to develop. E3 made the assumption that the CCGT cost serves as a floor for the cost of a renewable power purchase agreement (PPA) since until low-cost renewables are widely available, it is unlikely that developers will agree to supply power to California utilities below the market rate for new conventional resources. This assumption has a modest, upward impact on the total cost of complying with a 33% RPS.

Illustrative Timelines for Generation and Transmission Facilities

As mentioned above, this analysis created illustrative timelines for the generation and transmission facilities needed to meet a 33% RPS. These timelines show the time needed to reach a 33% RPS under three scenarios: a) historical experience without process reform, b) current practice including process reform and no external risks, and c) current practice with process reform and external risks. The study team constructed timelines only for the 33% RPS Reference Case and did not perform this analysis on the other three alternative 33% RPS cases.

This analysis also identified several external risks that are outside of the state's control. These risks include technology risk, financing risk, environmental impacts, and potential legal challenges and public opposition to transmission and generation permits. The report shows how these risks could cause delay despite the progress the state is making in streamlining current renewable generation and transmission permitting processes.

3 33% RPS Resource Portfolio Results

This section describes the renewable resource mixes developed for each 33% RPS case and presents the impact of these resource mixes on total statewide electricity expenditures, average statewide electricity costs, and GHG emissions relative to an all-gas scenario and the 20% RPS Reference Case. A brief overview of the methodology is provided below, with a more complete description in Appendix B.

In order to conduct the analysis, E3 first created an RPS Calculator, which is a Microsoft Excel spreadsheet model developed to aggregate the renewable cost and performance data and select renewable resources needed to meet the RPS target. The model identifies transmission investments that deliver renewable resources to load and conventional resources that are needed to meet energy and peak demand growth. It also calculates the cost and GHG impacts of a given portfolio of resources in 2020. Second, E3 calculated the renewable resource need to determine how much renewable energy the state needs to procure between now and 2020 to meet the 33% RPS. E3 used the Energy Commission's 2007 IEPR load forecast to project statewide electricity load in 2020, which included assumptions on the state's achievement of energy efficiency, demand response, combined heat and power, and the California Solar Initiative.[12] In order to fill this need, data was collected drawing from the sources described in Table 1. Next, each renewable project was placed into a resource zone, which is an aggregation of renewable resources in a contained geographic area. These zones were then ranked by both economic and environmental factors. From this data, the study team developed five different renewable energy cases, which are described in Table 2.

[12] California Energy Commission, "California Energy Demand 2008 – 2018 Staff Revised Forecast," CEC-200-2007-015-SF2, November 2007: http://www.energy.ca.gov/2007publications/CEC-200-2007-015/CEC-200-2007-015-SF2.PDF

Table 1. Data Sources Used in 33% RPS Implementation Analysis

Data Source	Description
CPUC Energy Division project database (ED Database)	The Energy Division maintains a database of renewable energy projects representing approximately 56 TWh of electricity that the IOUs have selected through RPS solicitations.[13] The projects are in various stages of completion, ranging from projects under negotiation (i.e., short-listed for negotiating a contract by an IOU), to projects that are online. Incorporating short-listed projects distinguishes this study from prior analyses by enabling it to take advantage of information about commercial interest in specific new renewable projects.
Renewable Energy Transmission Initiative	The RETI process developed a detailed and comprehensive database of renewable resource potential in California and neighboring states.[14] The RETI analysis provided a stakeholder-vetted engineering assessment of renewable resources at the project level by location and technology type. The RETI dataset relies on proxy projects that are based on expressed commercial interest, it does not include short-listed projects. In addition to renewable resource information, the RETI database categorized clusters of renewable development into renewable resource zones, which were extremely valuable in the estimates of resource development and transmission need.
The GHG Calculator	E3 developed a database of renewable resource potential throughout the WECC as part of its GHG modeling analysis for the CPUC, ARB, and the Energy Commission. The study team relied on the E3 database for information on renewable resources outside of California.[15]
Estimates of distributed renewable energy potential	E3 developed new estimates of the technical potential to connect distributed renewable generation in California. While the distributed solar photovoltaic technical potential estimates that were developed for this study are very high-level, they are useful for the purpose of testing the benefits and costs of distributed renewables relative to central station power plants to achieve a 33% RPS.

[13] The CPUC maintains a public version of this database: www.cpuc.ca.gov/renewables

[14] Renewable Energy Transmission Initiative: www.energy.ca.gov/reti/documents/index.html

[15] The E3 database compiled the data through GIS date from the National Renewable Energy Laboratory, the Energy Information Administration, the Energy Commission, and the Western Governor's Association. More detailed information is available here: http://ethree.com/CPUC_GHG_Model.html.

Table 2. 2020 Cases Developed for the 33% RPS Implementation Analysis

Case Name	Description
20% RPS Reference Case	Utilities procure 35 TWh of additional renewables to meet a 20% RPS target by 2020.
33% RPS Reference Case	Utilities procure 75 TWh of additional renewables to meet a 33% RPS target by 2020. There is heavy emphasis on projects that are already either contracted or short-listed with California IOUs, which includes a significant proportion of solar thermal and solar photovoltaic resources.
High Wind Case	Assumes less reliance on in-state solar thermal and more reliance on the less expensive wind resources in California and Baja.
High Out-of-State Delivered Case	Allows construction of new, long-line, multi-state transmission to allow California utilities to procure large quantities of low-cost wind and geothermal resources in other western states. Does not use tradable renewable energy certificates as a compliance tool. Thus, all out-of-state electricity is delivered to California.
High DG Case	Assumes limited new transmission corridors are developed to access additional renewable resources to achieve a 33% RPS. Instead, extensive, smaller-scale renewable generation is located on the distribution system and close to substations.

RENEWABLE RESOURCES NEEDED

Table 3 shows the calculation of the quantity of renewable resources that California utilities must procure between 2008 and 2020 to meet a specified RPS target – for both a 20% and a 33% RPS.

Table 3. New Renewable Resources Required to Meet a 33% RPS by 2020 in TWh

	20% RPS	33% RPS
2020 retail sales forecast [16]	308	308
Required RPS resources	62	102
RPS resources claimed by utilities in 2007[17]	27	27
Resources needed to reach RPS	*35*	*75*

RESULTING RPS RESOURCE MIXES

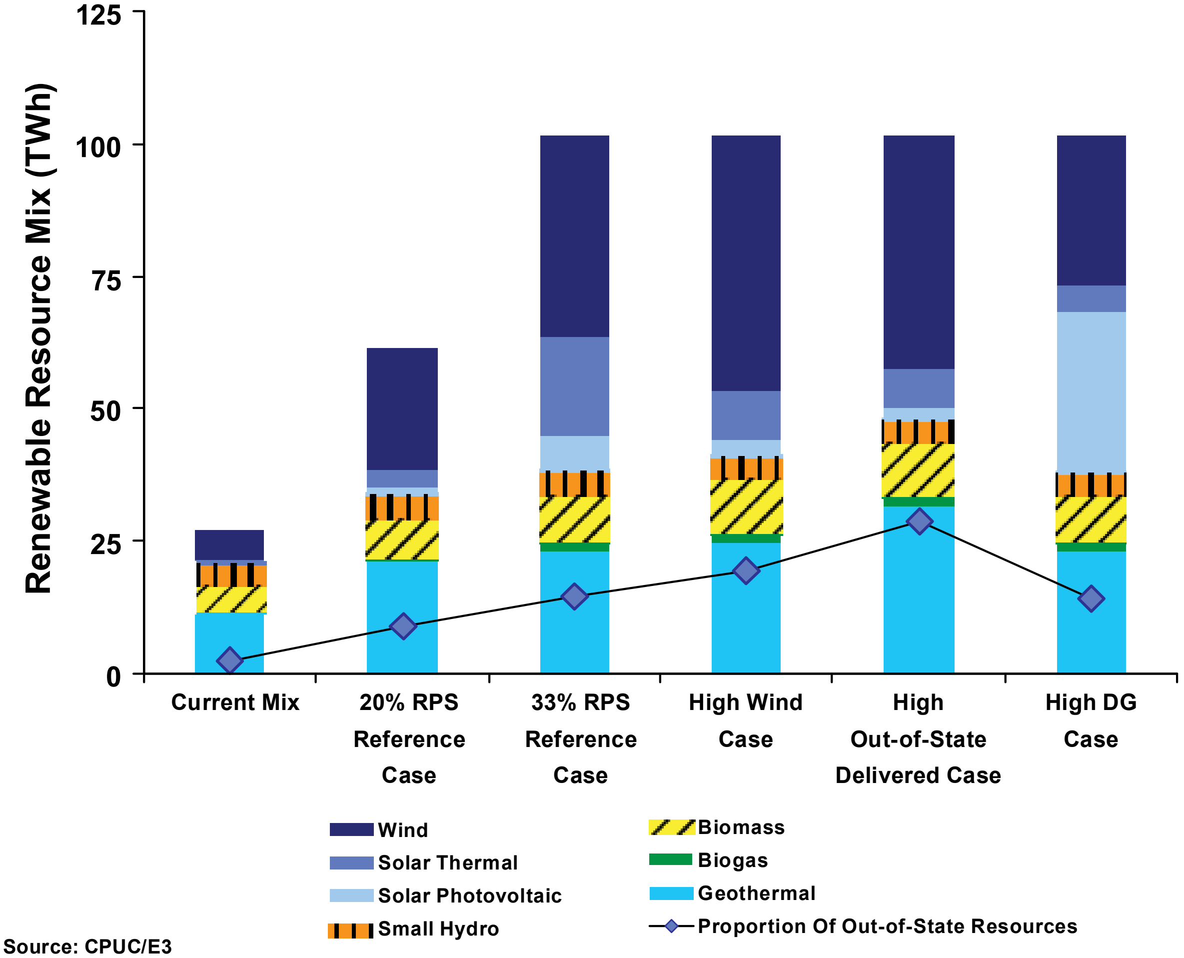
Figure 1 provides the renewable energy resource mixes for each RPS case, which were derived using the RPS Calculator. The renewable energy resource mixes for each case vary significantly across portfolios. The 33% RPS Reference Case has the most large-scale solar compared to all of the other cases. The High Out-of-State Delivered Case contains the largest proportion of out-of-state resources, such as geothermal energy, and nearly as much wind as the High Wind Case.

[16] Source: California Energy Commission, 2007, "California Energy Demand 2008 - 2018 Staff Revised Forecast," Energy Commission-200-2007-015-SF2, (excludes sales by California water agencies) extrapolated from 2018 to 2020 based on historic growth trends
[17] Source: Energy Commission 2007 Net System Power Report

The bioenergy and small hydro proportions do not vary greatly across the cases. The High DG Case includes a much larger proportion of solar PV than any other case.

Figure 1 also shows the level of renewable energy from the various resources in each case, inside and outside of California. All cases assume existing statutorily-required out-of-state energy delivery requirements.[18] The High Out-of-State Delivered Case and the High Wind Case have a higher proportion of renewable energy developed outside of California compared to the other cases. Thus, this study does not examine the potential for or costs and benefits of the use of tradable RECs with no delivery requirement as a compliance mechanism in the RPS program.

Figure 1. Renewable Resource Mixes in 2020 under Different Cases



Source: CPUC/E3

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[18] California Public Resources Code Section 25741(a) states that facilities located in California or with their first point of interconnection in the state are automatically deemed "delivered," eligible renewable energy from out-of-state facilities must be "scheduled for consumption by California end-use retail customers" to be counted for compliance with the RPS program. The RPS statute also allows "electricity generated by an eligible renewable energy resource [to] be considered 'delivered' regardless of whether the electricity is generated at a different time from consumption by a California end-use customer. The Energy Commission's RPS Eligibility Guidebook interprets this to mean that out-of-state energy may be "firmed" and "shaped," or backed up or supplemented with delivery from another source, before it is delivered to California.

Table 4 shows the locations of the renewable resources in the 33% RPS Reference Case. The resources fall into two categories: those that need additional transmission development, and those that do not. Resources that do not need new in-state transmission were aggregated into relatively homogenous clusters. Similar tables for the three alternative 33% RPS cases are included in Appendix C.

Table 4. Locations of Renewable Resource Zones in 33% RPS Reference Case

Resource Zones Selected in Reference Cases		
Included in 20% and 33% RPS Reference Cases		
	MW	**GWh**
Tehachapi	3,000	8,862
Distributed CPUC Database*	525	3,118
Solano	1,000	3,197
Out-of-State Early*	2,062	6,617
Imperial North	1,500	9,634
Riverside East	1,350	3,153
Included in 33% RPS Reference Case Only		
Mountain Pass	1,650	4,041
Carrizo North	1,500	3,306
Out-of-State Late*	1,934	5,295
Needles	1,200	3,078
Kramer	1,650	4,226
Distributed Biogas*	249	1,855
Distributed Geothermal*	175	1,344
Fairmont	1,650	5,003
San Bernardino - Lucerne	1,800	5,020
Palm Springs	806	2,711
Baja	97	321
Riverside East Incremental	1,650	3,869
Total	**23,798**	**74,650**

* Aggregations of renewable resources that do not need new in-state transmission development.

RPS COSTS IMPACTS AND GHG EMISSION REDUCTIONS

This section describes the cost impacts for each RPS case. Specifically, the 33% RPS cases are compared to the 20% RPS Reference Case. These costs, however, are uncertain for a number of reasons. Chief among these are: a) Use of planning-level data regarding technology cost and performance from RETI and other sources rather than contract prices associated with any particular project; b) Assumption of no changes in renewable technology costs or performance over time; c) Use of high-level estimates of transmission and renewable integration costs; d) Natural gas prices are highly volatile and may be very different from forecasted values; e) Use of a number of assumptions about GHG regulation including the cost of carbon dioxide (CO_2) allowances in 2020 and the allocation of allowance auction revenues to electric utility ratepayers. While new data that is forthcoming from RETI and the California ISO may help to refine cost estimates, uncertainty is inherent in any long-term planning exercise, which should be kept in mind when interpreting these results.

All-Gas Scenario and 20% RPS Reference Case

Average California electricity costs per kilowatt-hour are expected to increase substantially between now and 2020 even without new investments in renewable resources. Table 5 shows California's projected statewide electricity expenditures in 2008 and in 2020 for an all-gas scenario in which no new renewable projects are built after 2007. This all-gas scenario is designed to show the overall change in the California electricity system by 2020 if no additional renewable resources are built after 2007. Average electricity costs per kilowatt-hour are expected to increase by 16.7% from 2008 to 2020 under the all-gas scenario. This increase results from the need to maintain and replace aging transmission and distribution infrastructure, anticipated investments in advanced metering infrastructure and other smart grid capabilities, the cost of re-powering or replacing generators to comply with once-through cooling regulations, and the cost of procuring new conventional generating resources to meet load growth. Under the 20% RPS Reference Case (current law), the average electricity costs per kilowatt-hour increase would be 19.7% compared to 2008.

Table 5. Projected California Electricity Costs in 2020 (billions of 2008 dollars)

Category	2008	All-Gas Scenario in 2020	20% RPS Reference Case in 2020	33% RPS Reference Case in 2020
Existing and New Conventional Generation Fixed Costs	$8.5	$11.8	$11.1	$9.9
Existing and New Conventional Generation Variable Costs	$13.2	$16.5	$14.2	$11.6
Existing Transmission and Distribution	$15.1	$20.5	$20.5	$20.5
New Transmission for Renewables	N/A	N/A	$0.5	$1.8
New Renewable Generation and Integration	N/A	N/A	$4.3	$10.8
CO_2 Allowances[19]	N/A	$0.4	- $0.03	- $0.5
Total Statewide Electricity Expenditures	**$36.8**	**$49.2**	**$50.6**	**$54.2**
Average Statewide Electricity Cost per kWh	**$0.132/kWh**	**$0.154/kWh**	**$0.158/kWh**	**$0.169/kWh**

[19] Assumes that revenues from the auction of 108 MMT of CO_2 allowances (based on estimate 2008 electric sector emissions) are used to reduce utility rates. Does not include additional CO_2 costs that are reflected in higher market prices.

Implication: Electricity costs will increase significantly in 2020 compared to 2008, regardless of whether California mandates a 33% RPS or not.

33% RPS Cases

As shown in Table 6 and Figure 2, the cost premium from the 20% RPS Reference Case to the 33% RPS Reference Case is 7.1%, or $3.6 billion more in the year 2020. Table 6 also shows that the cost impact of meeting a 33% RPS does not vary greatly between the High Out-of-State Delivered Case and the High-Wind Case. Statewide electricity expenditures under these cases are $1.5 billion and $1.7 billion lower than the 33% RPS Reference Case, respectively, with the cost savings largely resulting from replacing large quantities of solar thermal resources with less costly wind resources (see Figure 13 in Appendix B for the levelized cost of each generation technology). The cost similarity between the High Wind Case and the High Out-of-State Delivered Case indicates that remote wind resources can be constructed and delivered to California at a similar, though slightly lower, cost compared to building local resources, which are of lower quality and also require in-state transmission upgrades. On the other hand, the out-of-state resource costs could be even lower through trading RECs with no delivery requirement since the scenarios studied here all assume California deliverability and thus transmission investment.

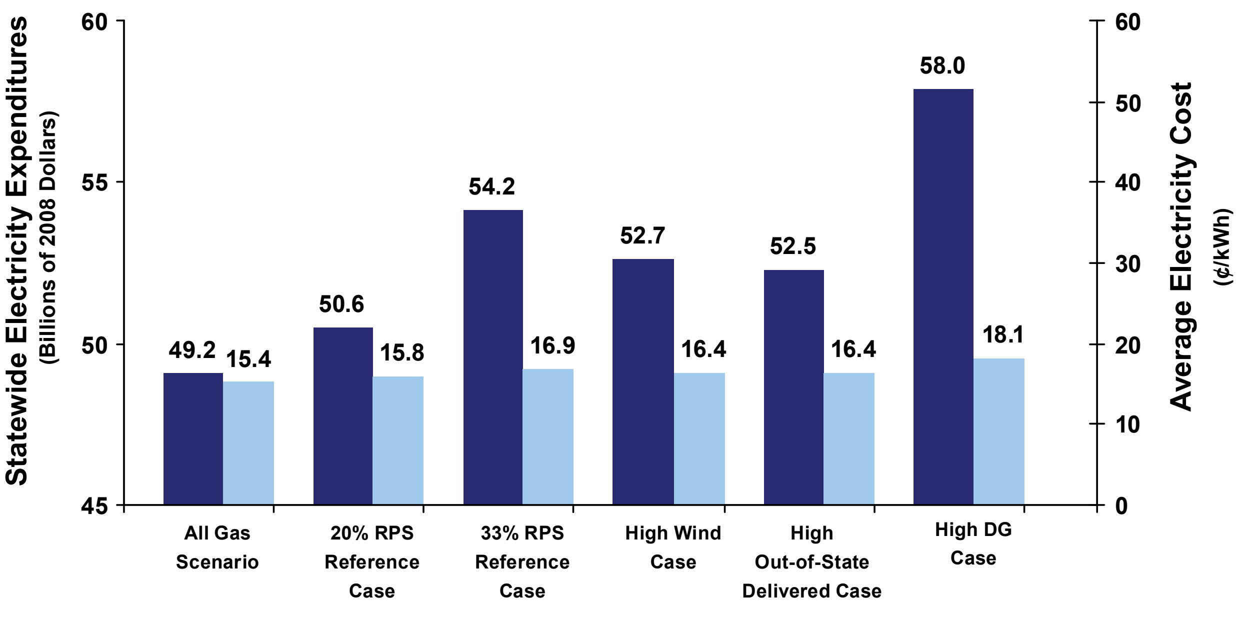
The cost impact of the High DG Case is significantly higher than the 33% RPS Reference Case, with a 14.6% cost premium compared to the 20% RPS Reference Case, and a 7% cost premium compared to the 33% RPS Reference Case. This is due to the heavy reliance on solar PV resources, which are currently much costlier than wind and central station solar.

Implication: The cost of a 33% RPS is higher than a 20% RPS under all four of the 33% RPS cases studied and the 33% RPS Reference Case is higher than all of the alternative RPS cases, except for the High DG Case.

Table 6. Costs and Cost Differences Between Alternative RPS Cases in 2020

Category	20% RPS Reference Case	33% RPS Reference Case	33% High Wind Case	33% High Out-of-State Delivered Case	33% High DG Case
Total Statewide Electricity Expenditures	$50.6	$54.2	$52.7	$52.5	$58.0
Average Statewide Electricity Cost	$0.158/kWh	$0.169/kWh	$0.164/kWh	$0.164/kWh	$0.181/kWh
Difference Relative to 20% RPS Reference Case	N/A	+$3.6	+$2.1	+$1.9	+$7.4
Percent Difference Relative to 20% RPS Reference Case	N/A	+7.1%	+4.2%	+3.8%	+14.6%
Difference Relative to 33% RPS Reference Case	N/A	N/A	-$1.5	-$1.7	+$3.8
Percent Difference Relative to 33% RPS Reference Case	N/A	N/A	-2.8%	-3.1%	+7.0%

Figure 2. Statewide Electricity Expenditures and Average Electricity Cost in 2020



Source: CPUC/E3

GHG Emission Reductions

This study only analyzed the GHG emissions associated with electricity generation and did not review the lifecycle emissions of each renewable technology, since that was beyond the scope of this analysis. The results indicate that a 33% RPS would reduce CO_2 emissions by approximately 29 million metric tons as compared to the all gas scenario, in which no new renewable projects are built after 2007. The CO_2 savings are similar for all of the 33% RPS cases, and are broadly consistent with the results of the GHG Calculator and the ARB analysis cited in the ARB Scoping Plan, which is 21.3 $MMTCO_2E$, despite differences in ARB's methodology for developing the 2020 baseline and a different set of electric sector CO_2 emission reduction measures.

SENSITIVITY OF RESULTS TO CHANGES IN INPUTS

In order to determine the sensitivity of the results to changes in key input assumptions, sensitivity analysis was conducted on the following factors: natural gas CO_2 allowance prices, higher levels of achievement of demand-side strategies such as energy efficiency and demand response, and the effect of a dramatic reduction in the installed cost of solar PV.

Natural Gas and CO_2 Price Sensitivity

The natural gas (gas) and CO_2 allowance price sensitivities are designed to test the results at the endpoints of a range of price expectations reflecting both the recent experience of price volatility and reasonable expectations.[20] Gas and CO_2 allowance prices are assumed to move together because increases in the price of either commodity will enhance the competitiveness of renewable resources by increasing the cost of fossil resources (relative to renewable generation) and reducing the overall cost impact of achieving a 33% RPS. Decreases in the cost of either commodity will have the opposite effect. The following endpoints were used to test effects of higher and lower gas and CO_2 allowance prices on the portfolios:

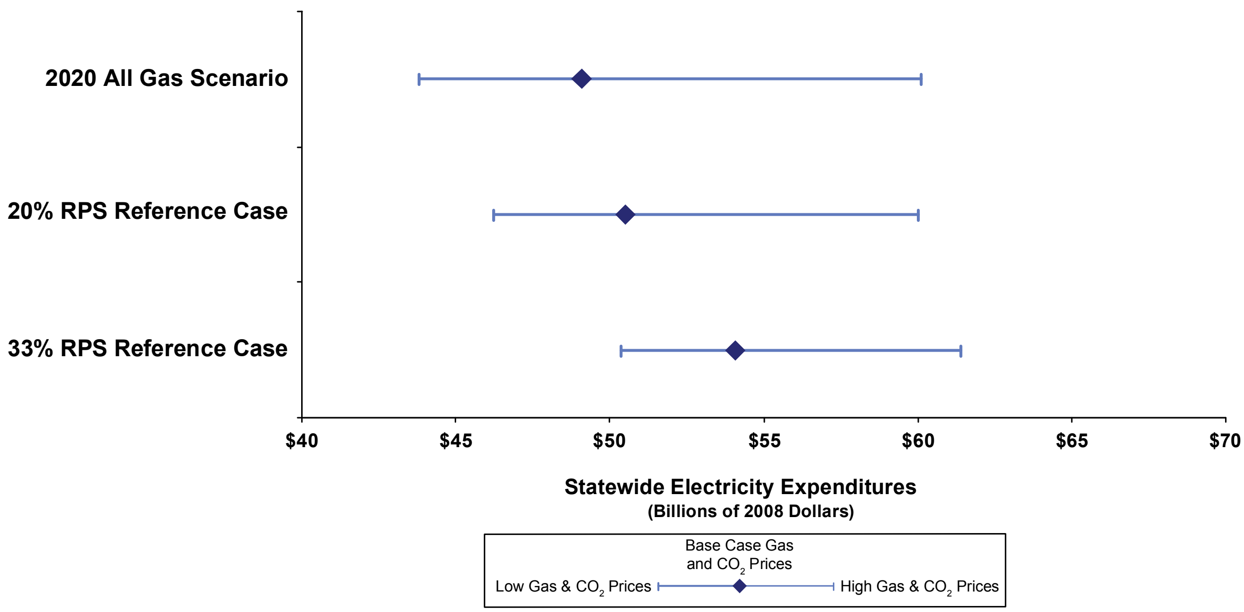
- **High Gas and CO_2 Allowance Prices:** 2020 gas price of $13.50/MMBtu at Henry Hub ($10.31/MMBtu in 2008 dollars delivered to California generators) and CO_2 allowance price of $100/tonne ($74.36 in 2008 dollars).
- **Low Gas and CO_2 Allowance Prices:** 2020 gas price of $6/MMBtu at Henry Hub ($4.74/MMBtu in 2008 dollars delivered to California generators) and CO_2 allowance price of $15/tonne ($11.15 in 2008 dollars).

These alternative assumptions were compared to the Base Case assumptions used in the RPS Calculator: 2020 gas price of $8.46/MMBtu at Henry Hub ($6.57/MMBtu in 2008 dollars delivered to California generators) and CO_2 allowance price of $42.46/tonne ($31.58 in 2008 dollars).[21]

[20] The high and low gas numbers are based on E3's expert judgment utilizing data from the Henry Hub over the past few years.
[21] Based on the Market Price Referent (MPR) methodology, see CPUC Decision 08-10-026

Figure 3 displays the range of statewide expenditures for the low, base, and high natural gas and CO_2 allowance prices. The range for the all gas scenario is $14.8 billion. The range of the 20% RPS Reference Case deceases to $12.5 billion and to $9.7 billion in the 33% RPS Reference Case. The alternative 33% RPS cases are not included in Figure 3 because their ranges are all approximately the same as the 33% RPS Reference Case.

Figure 3. Impact of Gas and CO_2 Allowance Prices on Statewide Expenditures



Implication: An increase in renewable energy penetration can decrease the range of statewide electricity expenditures by decreasing exposure to volatile fossil fuel prices. This could serve as a potential hedging strategy against volatile fossil fuel prices.

Impact of High Gas and CO_2 Allowance Prices

Figure 3 also shows that with High Gas and CO_2 allowance prices, the incremental cost of achieving the 33% RPS Reference Case is $1.7 billion or 2.9% higher relative to the 20% RPS Reference Case. This is substantially lower than the $3.6 billion or 7.1% cost impact under the Base Case Gas and CO_2 price assumptions.

Impact of Low Gas and CO_2 Allowance Prices

Under the Low Gas and CO_2 allowance prices, the incremental cost of achieving a 33% RPS compared to a 20% RPS is $4.5 billion, resulting in an increase of 9.7% relative to the 20% RPS Reference Case. However, it should be noted that while lower gas and CO_2 allowance prices raise the *relative* cost of achieving RPS goals, they exert a downward effect on electricity costs overall, such that overall electric costs are still lower under the Low Gas and CO_2 allowance prices with 33% RPS than under the Base Case gas and CO_2 allowance price assumptions with a 20% RPS.

Figure 3 also shows that the statewide electricity expenditures for the all gas scenario are still not as high as the expenditures for the 33% RPS Reference Case, despite the decreased volatility. This means that gas prices would need to exceed $13.87/MMBtu and CO_2 allowance prices would need to exceed $100/tonne for renewable energy to be an effective hedge against fossil fuel prices at a penetration level of 33%.

Implication: While renewable energy can provide a hedge against volatile fuel prices, a 33% RPS provides an effective hedge only against a combination of very high natural gas and CO_2 allowance prices. Thus, the "hedging value" associated with resource diversity is not a very strong policy justification for establishing a 33% RPS.

Low-Load Sensitivity: Sensitivity of Results to Accelerated Demand-Side Goals

California's energy policy goals call for aggressive achievements of energy efficiency and demand response as well as high penetrations of renewable energy. Success in achieving energy savings through efficiency programs may result in lower costs of complying with a 33% RPS by reducing the amount of renewable projects required to reach the goal. A low-load scenario could also result from other factors, such as an economic slowdown.

A Low-Load sensitivity was developed to test the interactive effects between aggressive demand-side measures and a 33% RPS. The assumptions are based on the Accelerated Policy Case scenario presented in the GHG Calculator and described in the joint Energy Commission/CPUC Final Decision on Greenhouse Gas Regulatory Strategies.[22] The Accelerated Policy Case has lower electric demand and lower retail sales than the 2007 IEPR load forecast used in the 33% RPS Reference Case due to assumptions explained in Table 7.

[22] CPUC Final Decision on Greenhouse Gas Regulatory Strategies, D.08-10-037, Proceeding R.06-04-009, pp. 34 - 36.

Table 7. Assumptions in the 33% RPS Implementation Analysis Reference Cases Compared to the Low-Load Sensitivity

	20% and 33% RPS Reference Case	Low-Load Sensitivity
Energy Efficiency (EE)	Energy Commission load forecast assumes 16 TWh of embedded EE (80% of the CPUC's 2020 EE goals)[23]	'High goals' EE scenario from GHG Calculator based on CPUC Itron Goals Update Study: 37 TWh[24]
Customer-Installed Solar PV	Energy Commission load forecast, 847 MW nameplate of customer-installed PV[25]	3,000 MW nameplate of customer-installed PV
Demand Response	Energy Commission load forecast (no incremental demand response)	5% reduction in peak demand, no energy savings (capacity only)
Combined Heat and Power (CHP)	Energy Commission load forecast (no incremental CHP assumed)	1,574 MW nameplate small CHP 2,804 MW nameplate larger

The Low-Load sensitivity assumes that electricity load growth in California is reduced from 43 TWh in the 33% RPS Reference Case to 11 TWh due to aggressive demand-side policies, while peak load growth is reduced from 10,600 MW to 2,000 MW. Because of this reduction in projected 2020 retail sales, the RPS resources needed in the 33% RPS Reference Case are reduced from 75 TWh to 64 TWh in the Low-Load sensitivity. *In the absence of mitigating factors, this would be expected to result in a substantial reduction in the incremental cost of achieving a 33% RPS relative to a 20% RPS.*

However, Table 8 shows that the statewide incremental electricity expenditures of the 33% RPS Reference Case compared to the 20% RPS Reference Case is *higher* under Low-Load assumptions than under Base Case assumptions – $4 billion in incremental costs under Low-Load assumptions versus $3.6 billion under the Base Case load. This result is counterintuitive – all else being equal, one would expect the incremental costs of the Low-Load sensitivity to be lower since it requires a smaller quantity of renewable generation. Further exploration is required to determine the cause of this counterintuitive result.

[23] The Energy Commission assumed the remaining 20% of the 2020 EE goals impacts were "uncommitted," and therefore excluded from the state's official forecast. In D.07-12-052, the CPUC assumed that 100% of the 2020 EE goal impacts would be realized for procurement purposes. The Energy Commission load forecast does not take into account the Big Bold goals the CPUC established in D.07-10-032.
[24] This scenario does not take into account the Big Bold goals the CPUC established in D.07-10-032.
[25] The 2007 IEPR load forecast assumed 847 MW of customer-side PV, a fraction of the 3,000 MW California Solar Initiative goal.

Table 8. Statewide Electricity Expenditures in 2020 for the 20% and 33% RPS Reference Cases Under the Low-Load Sensitivity (billions of 2008 dollars)

Costs	Base Case Loads	Low-Load Sensitivity
Total Electricity Expenditures, 20% RPS Reference Case	$50.6	$46.4
Total Electricity Expenditures, 33% RPS Reference Case	$54.2	$50.4
Incremental cost of 33% RPS Reference Case	$3.6	$4.0
Percent Difference Relative to 20% RPS Reference Case	7.1%	8.6%

Table 9 shows the net qualifying capacity[26] of all resources added for the 20% and 33% Reference Cases under both the Base Case and Low-Load sensitivity. After considering peak demand growth, an assumed 17% planning reserve margin, and the need to replace generators using once-through cooling, the total need for new capacity is 19,022 MW. Demand-side achievements reduce the needed capacity to 9,053 MW under the Low-Load Sensitivity.

Exactly 19,022 MW of capacity is added under the 20% Reference Case. However, 21,002 MW of capacity is added under the 33% RPS Reference Case, resulting in a capacity surplus of 1,980 MW. *This occurs because of the timing challenges of adding new renewables.* The model adds conventional resources to meet demand growth in the early years, before most of the renewable resources are online. The addition of large quantities of new renewables in the later years results in a temporary capacity surplus. The 2020 surplus is relatively small – 1,980 MW – under Base Case load growth assumptions. However, the surplus amounts to ***5,313 MW*** under the Low-Load sensitivity.[27] *Under the Low-Load sensitivity, the pace of required renewable resource development is so rapid compared to load growth that a substantial surplus of capacity is all but unavoidable.*

Under the 20% RPS Reference Case, demand-side programs result in substantial avoided capacity investments, or capacity savings. However, avoided capacity investments from demand-side programs are reduced under the 33% RPS Reference Case and dramatically reduced under the Low-Load sensitivity. This reduced savings from avoided capacity investments outweigh cost savings resulting from decreased renewable energy procurement. This causes the incremental cost of the 33% RPS Reference Case to be higher under the Low-Load sensitivity than under the Base Case load growth assumptions.

Note that this effect is due strictly to the need to procure *capacity* to meet peak demand requirements, and it occurs irrespective of the *energy* benefits of new renewables. It is possible that this peak capacity surplus could allow earlier retirement of fossil peaking generators. However, further study would be required to identify candidate generators and ensure that they

[26] Net qualifying capacity is the capacity value of the resource that can be counted toward resource adequacy requirements. This value is equal to the nameplate capacity for thermal generators, but is based on expected output during peak periods for intermittent renewable resources.
[27] Note that this analysis likely understates this effect, because renewable resource integration costs were treated as a simple, $/MWh adder. If new conventional resources are required to integrate wind and solar generation, the resulting capacity surplus would be larger under the 33% RPS cases.

are not needed to meet local reliability requirements or to ensure reliable system operations while integrating thousands of megawatts of new intermittent renewables.

Table 9. 2020 Capacity Balance Under the 20% and 33% RPS Reference Cases for the Base Case and Low-Load Sensitivity Load Growth (MW)

2020 Capacity Need, Additions, and Surplus	Base Case Loads		Low-Load Sensitivity	
	20% RPS Reference Case	33% RPS Reference Case	20% RPS Reference Case	33% RPS Reference Case
Growth in Peak Demand, 2008-2020	10,602	10,602	2,082	2,082
Additional Capacity Needed to Meet 17% Planning Reserve Margin[28]	1,802	1,802	354	354
Cumulative Retirements of Once-Through Cooling Generators[29]	6,617	6,617	6,617	6,617
Required Additions in Dependable Capacity	***19,022***	***19,022***	***9,053***	***9,053***
Dependable Capacity From New Renewables[30]	4,604	13,024	3,243	11,352
Capacity Added From Once-Through Cooling Repowering[31]	2,883	2,883	2,883	2,883
Cumulative Combustion Turbines and CCGTs Added for Resource Adequacy[32]	11,535	5,095	2,927	131
Total Capacity Additions	***19,022***	***21,002***	***9,053***	***14,366***
Capacity Surplus[33]	**0**	**1,980**	**0**	**5,313**

Implication: If the state does not plan for interactions between energy efficiency, 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.

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[28] Calculated as 17% of peak demand growth
[29] Based on a high-level analysis of once through cooling generators that are candidates for retirement
[30] Based on summer, peak period net qualifying capacity values, available at http://www.caiso.com/202f/202f9a882ec90.xls
[31] These generators are assumed to be needed to meet local reliability requirements, and are therefore the same in all cases.
[32] Remaining resources needed to meet resource adequacy requirements
[33] There is a capacity surplus in 2020 in the 33% RPS Reference Case because conventional resources are required to meet load growth in the early years, before the renewables can come online.

This result highlights the need for coordination among demand-side and supply-side programs to ensure compatibility and efficiency. For example, if the RPS portfolio is likely to result in substantial penetration of new solar thermal resources with storage, the resulting capacity surplus would reduce the need for demand response. Alternatively, if the RPS portfolio is heavy in wind resources that produce mostly at night, efficiency programs that target night time energy use such as outdoor lighting programs would be substantially less valuable. These interactions also depend strongly on the timing of new resource development; implementing California's aggressive energy policy goals over a longer period of time would reduce the likelihood of negative interactions among the various programs because programs could be adjusted along the way more easily.

Solar PV Cost Reduction Sensitivity

The Solar PV Cost Reduction sensitivity explores the impact of lower solar PV costs on the cost of meeting a 33% RPS. The solar energy industry is currently small relative to other renewable technologies, and technological innovations continue to improve solar PV's performance and reduce the cost of manufacturing. The solar PV industry expects that continued technological improvements and economies of scale will substantially reduce the cost of solar technology by 2020. The pace of such innovation is highly uncertain, however, and the delivered cost of energy depends on a number of other factors besides the manufactured component cost, not least of which is the continued willingness of the federal government to grant generous tax incentives, such as the investment tax credit. Despite this uncertainty, it is helpful to consider how solar PV innovation might change the cost impacts of a resource mix with high solar PV penetration.

The Solar PV Cost Reduction sensitivity is based on the thin-film cost sensitivity included in the RETI Phase 1B report,[34] and assumes that market transformation reduces the installed cost from approximately $7/Watt-equivalent (W-e)[35] today for crystalline solar PV to $3.70/W-e for thin-film solar PV by 2020. RETI derived this number from goals and cost targets that solar PV manufacturers and developers provided. This assumption lowers the delivered energy cost of a typical solar PV facility from $306/MWh to approximately $168/MWh. These cost reductions were modeled as a *sensitivity*, meaning that the impact of the cost reductions were simply calculated on the High DG and 20% RPS and 33% RPS Reference Cases.

The impact of this sensitivity is presented in Figure 4. As a result of the assumed cost reductions, statewide electricity expenditures decrease by $4.6 billion under the High DG Case and by $1.9 billion under the 33% RPS Reference Case. Statewide electricity expenditures are $53.4 billion under the High DG Case and $52.3 billion under the 33% RPS Reference Case. Thus, the Solar PV Cost Reduction sensitivity results in the High DG Case having similar overall costs to the 33% RPS Reference Case and other renewable resource mixes that depend on central station renewable generation.

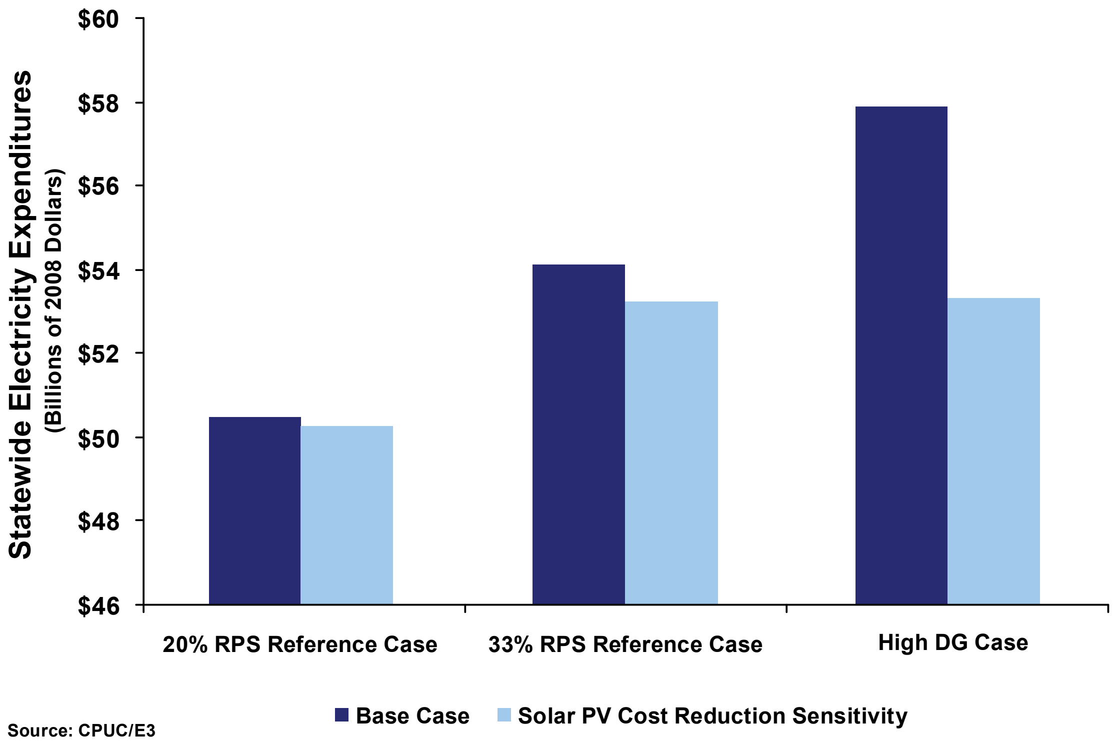
[34] The RETI Phase 1B report is available at:
http://www.energy.ca.gov/2008publications/RETI-1000-2008-003/RETI-1000-2008-003-F.PDF

[35] Watt-equivalent is a term used for solar PV that refers to grid-equivalent Watts after considering DC-AC conversion losses. $7/Watt-equivalent corresponds to approximately $5.83/nameplate Watt, and $3.70/W-e corresponds to $3.08/nameplate Watt.

These study results, however, are uncertain and come with a number of caveats. First, and most importantly, the thin-film sensitivity number used is very aggressive and the distributed solar PV technical potential estimates are not based on an engineering analysis. Second, there was no detailed analysis conducted of the cost difference of developing solar PV at various sizes and locations. Instead, rooftop solar PV was assigned an 8% cost premium and a 21% capacity factor penalty relative to ground-mounted solar PV. Third, simple, high-level assumptions were made about the distribution and transmission costs – or savings, depending on location – associated with interconnecting solar PV. Fourth, an implementation analysis of integrating such high levels of solar PV on the distribution system was not included in the analysis. Finally, the solar PV industry is still relatively small (though growing rapidly), and there is some question whether the solar PV industry can manufacture and supply the equipment at this level without leading to supply-chain constraints. A next step could be to conduct an implementation analysis on the market and regulatory barriers associated with the levels of solar PV in the High DG Case.

Implication: If solar PV experiences significant cost reductions, then a renewable portfolio with substantial quantities of solar PV could be much more cost-effective compared to today's solar PV market prices. The cost-effectiveness of the overall portfolio will depend on the program delivery costs; the High DG Case only uses the technology cost of solar PV, and not the deployment or program implementation costs, which would be higher due to significantly higher transaction costs to deploy thousands of solar PV projects.

Figure 4. Cost Savings Due to Solar PV Cost Reduction Sensitivity



Source: CPUC/E3

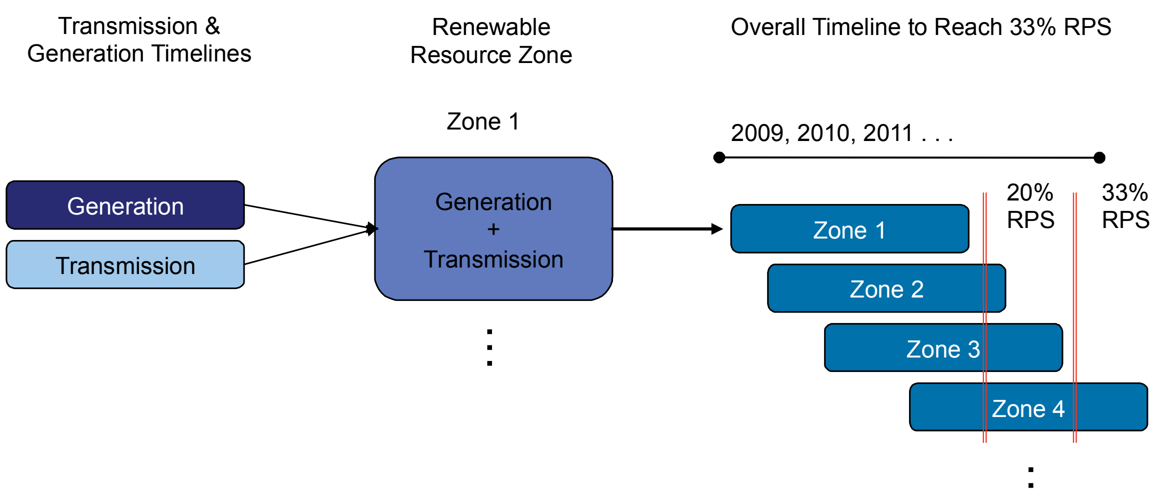
4 33% RPS Reference Case Illustrative Timelines

This section addresses the question of timing: whether the renewable generation and transmission needed for a 33% RPS can be built by 2020. Through the analysis described in this section, CPUC staff sought to understand the nature of the generation and transmission resources needed over time and the impact of ongoing reforms on the development of those resources, to identify areas where further reform is needed, and to understand the potential impacts of various risks on progress towards the 33% RPS goal.

To simplify this timeline analysis and to evaluate California's current resource contracting path, only the time and implementation challenges associated with the development of the 33% RPS Reference Case were evaluated. This section identifies some of the factors that could affect the timing of the generation and transmission development in the 33% RPS Reference Case, and thus the date by which the state could reasonably expect to reach a 33% RPS.

In order to construct illustrative timelines for the 33% RPS Reference Case, the project team first created generic timelines that estimate the permitting and construction times for generation projects – by technology, size, and permitting jurisdiction – and for transmission projects. These generic generation and transmission timelines were then used to create timelines for each resource zone selected in the 33% RPS Reference Case. Finally, the resource zone timelines were combined to create an overall timeline for the 33% RPS Reference Case. Those generation projects in the Reference Case that are *not* dependent on new in-state transmission were assumed to be developed in parallel with the "zone" resources, so that the 33% RPS is achieved with the full development of the last zone. Figure 5 illustrates this process.

Figure 5. Process for Developing 33% RPS Reference Case Timelines



Source: CPUC/Aspen

INDIVIDUAL RESOURCE ZONE TIMELINES

In order to quantify the time needed to develop all the transmission and generation required in the 33% RPS Reference Case, individual timelines were developed for each of the resource zones included in the 33% RPS Reference Case, using the methodology and generation and transmission timelines described in Appendix B. The resource zones that need new transmission are listed in Table 10. In some cases, two resource zones can share one major transmission project.

Table 10. Renewable Resource Zones that Need New Transmission for 20% and 33% RPS Reference Cases

Resource Zone	MW	GWh
Included in 20% and 33% RPS Reference Cases		
Tehachapi	3,000	8,862
Solano	1,000	3,197
Imperial North	1,500	9,634
Riverside East	1,350	3,153
Included in 33% RPS Reference Case Only		
Riverside East (incremental)	1,650	3,869
Mountain Pass	1,650	4,041
Carrizo North	1,500	3,306
Needles	1,200	3,078
Kramer	1,650	4,226
Fairmont	1,650	5,003
San Bernardino - Lucerne	1,800	5,020
Palm Springs	806	2,711
Baja	97	321

<u>Transmission and Generation Development in a Resource Zone</u>

Because of its longer development horizon, transmission is nearly always the critical path item in the development of a zone. Speeding the approval and development of transmission projects would thus facilitate earlier development of resource zones. This result is already well understood in California, and significant efforts are underway at both the state and federal level to expedite the review, planning, and permitting of appropriate transmission lines to support delivery of renewable resources.

Generation projects in California are subject to environmental review and permitting by county, state, or federal agencies, depending on the project's technology type, size, and location (see Figure 15 in Appendix B for a description of these categories and permitting jurisdictions). Table 11 shows how the generation projects in the 33% RPS Reference Case are distributed among permitting jurisdictions. Although this distribution is particular to the set of resources chosen for the 33% RPS Reference Case, the table gives a sense of the order of magnitude of the permitting required under any 33% RPS portfolio.

Table 11. Permitting Jurisdiction for Generation Projects in the 33% RPS Reference Case

Jurisdiction	Number of Generation Projects
Solano County	9 projects
Kern County	10 projects
Imperial County	7 projects
Riverside County	11 projects
Los Angeles County	13 projects
San Bernardino County	16 projects
San Luis Obispo County	6 projects
Energy Commission (sole or joint)	30 projects
Bureau of Land Management or Other Federal Agency (sole or joint)	46 projects in California (mainly Southern CA) 2 projects in Baja (Presidential Permit) 21 projects other Out-of-State or International Imported

Implication: The number of projects that may require review and approval by these jurisdictions now and in the coming years highlights the need for a major increase in trained specialists and staffing and consulting resources to process these permit applications within the timeframe of a 33% RPS by 2020.

Transmission and Generation Timing Considerations

Some delay is generally expected between completion of a transmission line and full use of that line. This delay results from the generation developer's need for certainty about transmission availability before investing capital into project development activities. Assuming that renewable generation developers will not begin construction until a final permit for the required transmission line is issued,[36] <u>all</u> generation projects in a renewable zone would have to complete construction in parallel with the construction of the transmission line in order to avoid the generation-transmission time lag. Such rapid and simultaneous generation development seems unlikely, particularly in the case of capital-intensive technologies like solar thermal and geothermal.

This situation may be exacerbated in California in the next few years because of the amount of generation that is dependent on new transmission and that must come online quickly. For example, if multiple generators in a renewable resource zone are dependent on one major transmission project, and they all plan their project development schedules around estimates of that transmission's availability, they may all enter the permitting phase at the same time, potentially overloading the relevant permitting authority and leading to delays in the issuance of

[36] Generators are often not able to secure full financing until transmission assurance is received. Without financing, many generators will not be able to move far into the permitting process, leaving even more work to be done <u>after</u> the transmission permit is issued.

site permits. For instance, the illustrative San Bernardino-Lucerne resource zone in Figure 6 includes many projects requiring Bureau of Land Management (BLM) and Energy Commission approval, and concurrent permitting of all projects could prove to be a challenge.

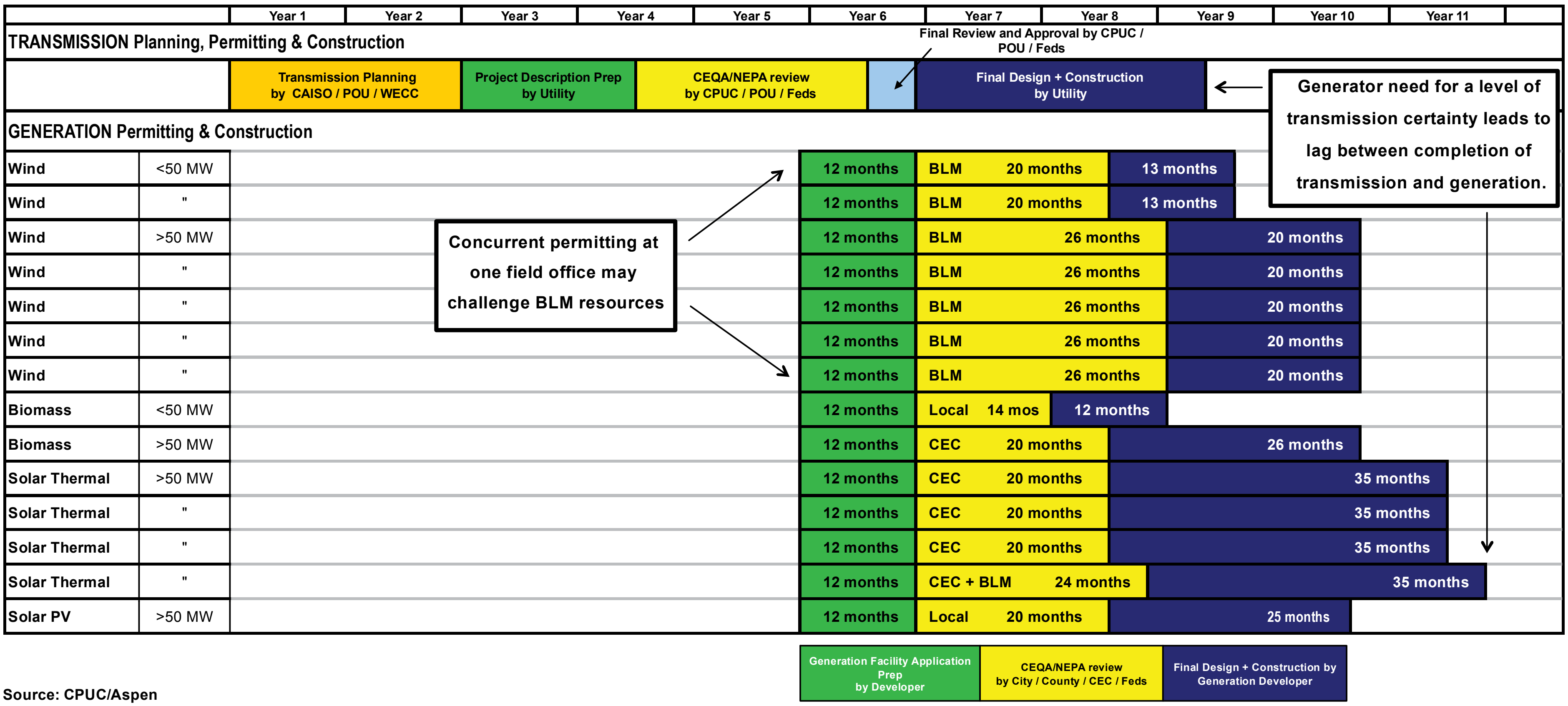
Implication: The interaction between transmission and generation time lag can be a significant source of time delay. State and federal agencies should focus on ensuring that permitting agencies are prepared to process large numbers of generation applications in a timely manner, particularly in areas where new transmission is expected or already permitted.

Figure 6 presents an illustrative timeline for the San Bernardino-Lucerne resource zone and demonstrates how the timelines for a mix of renewable generation projects and one major new transmission line are combined to provide an overall timeline for the development of that resource zone. This zone timeline also highlights the interaction between the timing of transmission and generation development that can result in a lag between transmission completion and full utilization of that line.

Figure 6 Timeline Assumptions:

- Individual generation projects in this zone are those included in the 33% RPS Reference Case; one major new transmission line and perhaps some smaller lines would be needed to access and deliver the required amount of generation.
- Generation and transmission timelines are based on the generic timelines described in the Methodology (Appendix B). They reflect recent experience with actual projects.
- Development of generation begins one year before final approval of the required transmission line because of the need for a degree of certainty regarding transmission availability to facilitate generation project financing.

Figure 6. Example of Generation and Transmission Timelines Combined to Create a Resource Zone Timeline (San Bernardino – Lucerne Resource Zone)



Source: CPUC/Aspen

<u>Result</u>: The transmission in this zone takes longer to develop than the generation. However, the generation developers' need for a degree of certainty regarding transmission availability in order to obtain financing and invest in project development causes them to delay project development until several years into the transmission development process. This results in a 29-month period between completion of the transmission and full development of the zone.

ILLUSTRATIVE TIMELINES FOR THE 33% RPS REFERENCE CASE

Following the completion of timelines for each of the zones in the 33% RPS Reference Case, the resource zone timelines were combined to create an overall timeline for the 33% RPS Reference Case. CPUC staff adapted this overall 33% RPS timeline to depict three scenarios using the distinct sets of assumptions presented in Table 12. Timeline 1 depicts the state's relatively recent historical experience in transmission and renewable development, but does not include process reforms or external risks. Timeline 2A and 2B reflect the possible effects of the state's current and ongoing reforms to expedite and streamline the permitting and review processes. Unlike Timeline 2A, Timeline 2B considers the possible effects of external risks that could undermine the efforts at reform. Timeline 2A is not realistic or plausible since it does not include external risks, but rather provides a reference point upon which Timeline 2B is built.

Table 12. Description of Illustrative Timelines for the 33% RPS Reference Case

Timeline	Description
Illustrative Timeline 1: Historical experience without process reform	This scenario is based on the state's experience with generation and transmission development over the last 10-15 years. Timeline assumes transmission planning, permitting, and construction processes that are almost entirely sequential.
Illustrative Timeline 2A: Current practice with process reform and no external risks	Development trajectory if California successfully implements transmission and generation reforms that are already underway. Timelines are unrealistic because they assume no delays from external factors that are not addressed by current reforms.
Illustrative Timeline 2B: Current practice with process reform and external risks	Development trajectory if state successfully implements reforms, but factors outside the direct control of state agencies, such as technology failure, financing difficulties, and legal challenges, cause delay or failure of some projects necessary to achieve the 33% RPS Reference Case.

Several assumptions are common to all of the timelines:

- For purposes of this timeline analysis, "achievement of the 33% RPS target" implies achievement of the full 33% RPS Reference Case buildout, which was developed to serve 33% of <u>2020</u> retail sales. The 33% RPS Reference Case is not updated to account for expected load growth after 2020 that would cause the 33% RPS target, an energy and not a capacity goal, to increase slightly every year, even though, in all of the timelines, the 33% RPS goal is not achieved until after 2020.
- A delay of 30 months – an approximation of the delay depicted in Figure 6 – is assumed to occur between transmission completion and full generation buildout in all scenarios, since California has not yet implemented processes that would address this delay.
- The resource zones in the 20% RPS Reference Case (the zones at the top of each timeline) are assumed to be accessed by actual transmission projects that are already in some late stage of development or are otherwise expected to have shorter development timelines due to jurisdiction and location.

- Development horizon for the Baja zone (Zone 6) is constant in all three scenarios, as it would be only minimally affected by the California process reforms assumed in Timelines 2A and 2B.
- No specific generation is associated with the Path 15 upgrade, but this upgrade was identified as likely needed to maintain reliability under the 33% RPS Reference Case, given the large amount of generation added in Southern California, relative to Northern California. The assumed short time horizon reflects transmission planning efforts now underway. Other upgrades will no doubt be needed to maintain system reliability; this analysis did not attempt to identify all of those upgrades.

ILLUSTRATIVE TIMELINE 1: HISTORICAL EXPERIENCE WITHOUT PROCESS REFORM

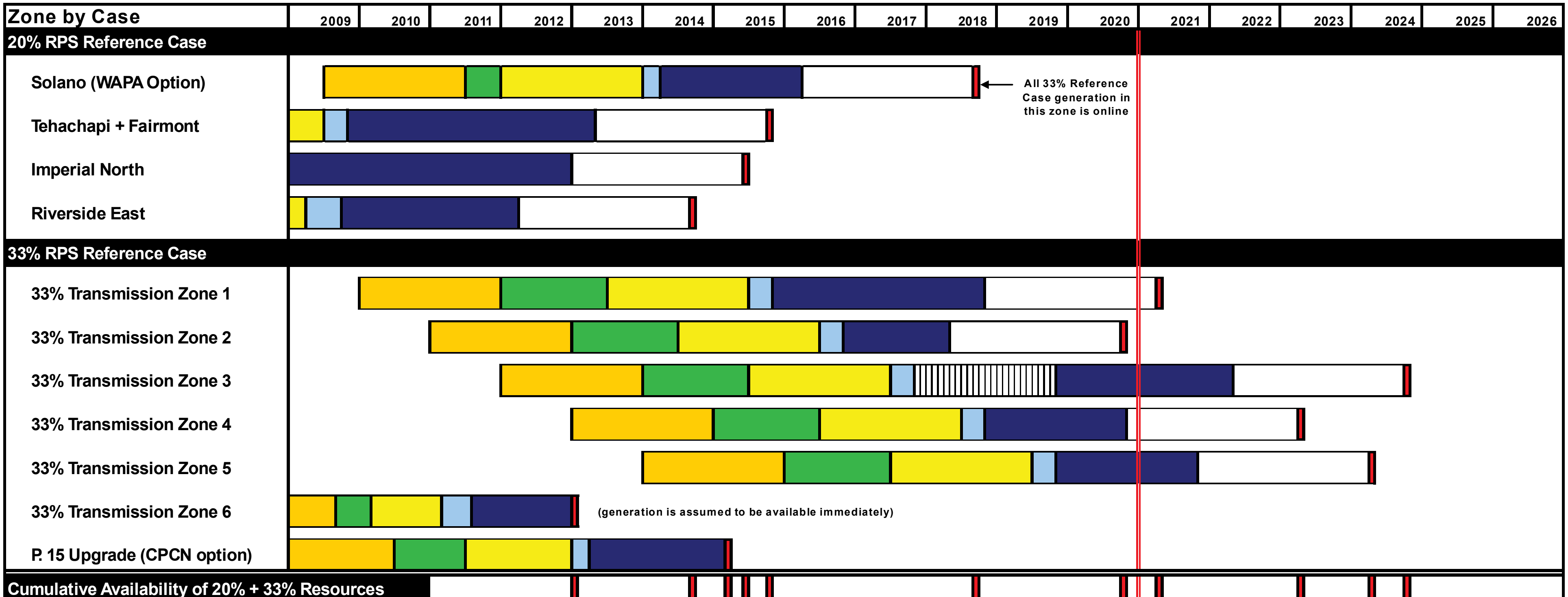
Timeline 1 (Figure 7) reflects the timeline for achieving the 33% RPS Reference Case under the "historical experience without process reform" scenario. The purpose of this timeline is to demonstrate the time savings achieved if current and ongoing process reforms are successful. Under this scenario, the 33% RPS Reference Case is achieved in 2024. Because the 33% RPS Reference Case closely mirrors California's recent renewable resource development path (as represented through IOU contracts), this timeline indicates that the state would be unlikely to meet a 33% RPS by 2020, if past transmission planning and permitting processes and the associated transmission-generation time interactions were to continue. This timeline does not assume any external risks, such as those associated with Timeline 2B (Figure 9), so this timeline is not realistic.

Timeline Assumptions:

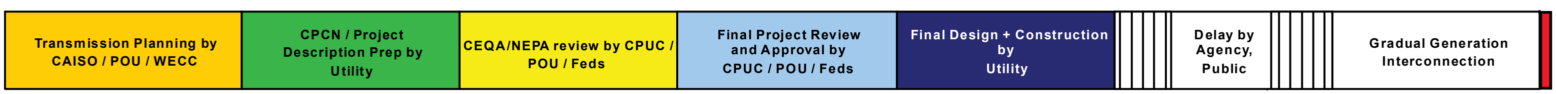
- Timelines for each phase of the generation and transmission development processes are based on California experience over the last 10-15 years.
- Transmission planning, permit preparation, environmental review, and final project design/construction happen in sequence, with very little overlap.
- One new transmission project enters the development process each year, starting in 2009. Timelines are shortened in cases where real transmission projects already in some stage of development would access a zone identified in the 20% or 33% RPS Reference Cases.
- One significant, two-year delay is assumed for the transmission project needed to access Zone 3. Based on recent experience, such a delay could result from permitting delays at a federal agency, or other factors. This delay is assigned randomly for illustrative purposes only, and does not relate to any specific concerns anticipated with Zone 3. The purpose of the delay is to illustrate that the delay of any transmission project, regardless of which one, significantly impacts the 33% RPS schedule.
- Beyond one 2-year delay to a transmission project's construction, *Timeline 1 assumes none of the other external delays that are considered in Timeline 2B.*

Implication: California must implement changes to its transmission and generation planning and permitting processes now to achieve a 33% RPS by 2020. Several critical reforms have already been implemented, and several more are in the early stages of development and implementation. Timeline 1 reflects empirical experience in California to date, and highlights how crucial it is that the process reforms now underway in California be implemented successfully.

Figure 7. Illustrative Timeline 1 for the 33% RPS Reference Case: Historical Experience Without Process Reform



MW available per year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Biomass							74	74	74	74	74	74	165	165	165	165	165	165
Geothermal							1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,144	1,144	1,144	1,144
Solar thermal + PV						1,349	2,008	2,008	2,008	2,008	2,008	3,508	6,056	6,056	7,479	9,875	9,875	9,875
Wind					100	100	4,397	4,397	4,397	5,397	5,397	5,397	6,208	6,208	6,411	7,672	7,672	7,672
Total Zone Resources					100	1,449	7,599	7,599	7,599	8,599	8,599	10,099	13,549	13,549	15,199	18,856	18,856	18,856



Source: CPUC/Aspen

<u>Result</u>: The 33% RPS Reference Case is achieved in 2024, assuming no external risks.

Note: While the CPUC averages approximately 18 months for California Environmental Quality Act review and Certificate of Public Convenience and Necessity approval for transmission siting cases in general, more conservative assumptions were used here to account for the likely larger and more controversial nature of these new required projects.

ILLUSTRATIVE TIMELINE 2A: CURRENT PRACTICE WITH PROCESS REFORM AND NO EXTERNAL RISKS

Timeline 2A (Figure 8) reflects the timeline for achieving the 33% RPS Reference Case under "current practice with process reform and no external risks." The purpose of this timeline is to provide a reference point to show the effects of process reforms without the potential undermining effects of any external risks not within the state's control. This timeline assumes the full implementation of several process reforms instituted at California agencies and other entities within the last three years, as well as successful implementation of other reforms that are now only in the early stages of development and implementation.

Timeline Assumptions:

- Reflects successful implementation of the significant process reforms currently underway at the California ISO and the CPUC. These reforms, which are described in this section, are administrative in nature and do not require any changes to existing law.
- Two new transmission projects enter the development process in 2010 as a result of RETI, the California ISO's Generation Interconnection Process Reform, and other processes, with one major renewable transmission project beginning development each year between 2011 and 2013.
- The two-year delay assumed in Timeline 1 for the transmission project needed to access Zone 3 is removed since this timeline is meant to show only the effects of process reform. Assumes no resource constraints in processing transmission and generation permitting applications.
- All of the transmission lines needed for the 33% RPS are assumed to involve the California ISO planning process, rather than a planning process at a publicly-owned utility (POU). This assumption is applied to simplify the presentation of the timing of transmission planning. Although a mix of POU-and California ISO-controlled lines will likely be developed, this assumption is not unreasonable, given the California ISO's responsibility for planning and operating most of the state's grid.
- *Timeline 2A assumes none of the other external delays that are beyond the state's control. These risks are factored into Timeline 2B.*

Timeline 2A indicates that the generation and transmission infrastructure required for a 33% RPS could be developed by 2021 with the successful implementation of these reforms, assuming no external delays (those outside the direct control of the state). The 33% RPS is achieved three years earlier in Timeline 2A than in Timeline 1. While Timeline 2A is likely unrealistic since it assumes no risks beyond those addressed by these reforms, it highlights the importance of current efforts underway to reform planning and permitting processes. Timeline 2B will show the potential impact of external risks, those outside of the state's control, on the gains realized through the reforms highlighted in Timeline 2A.

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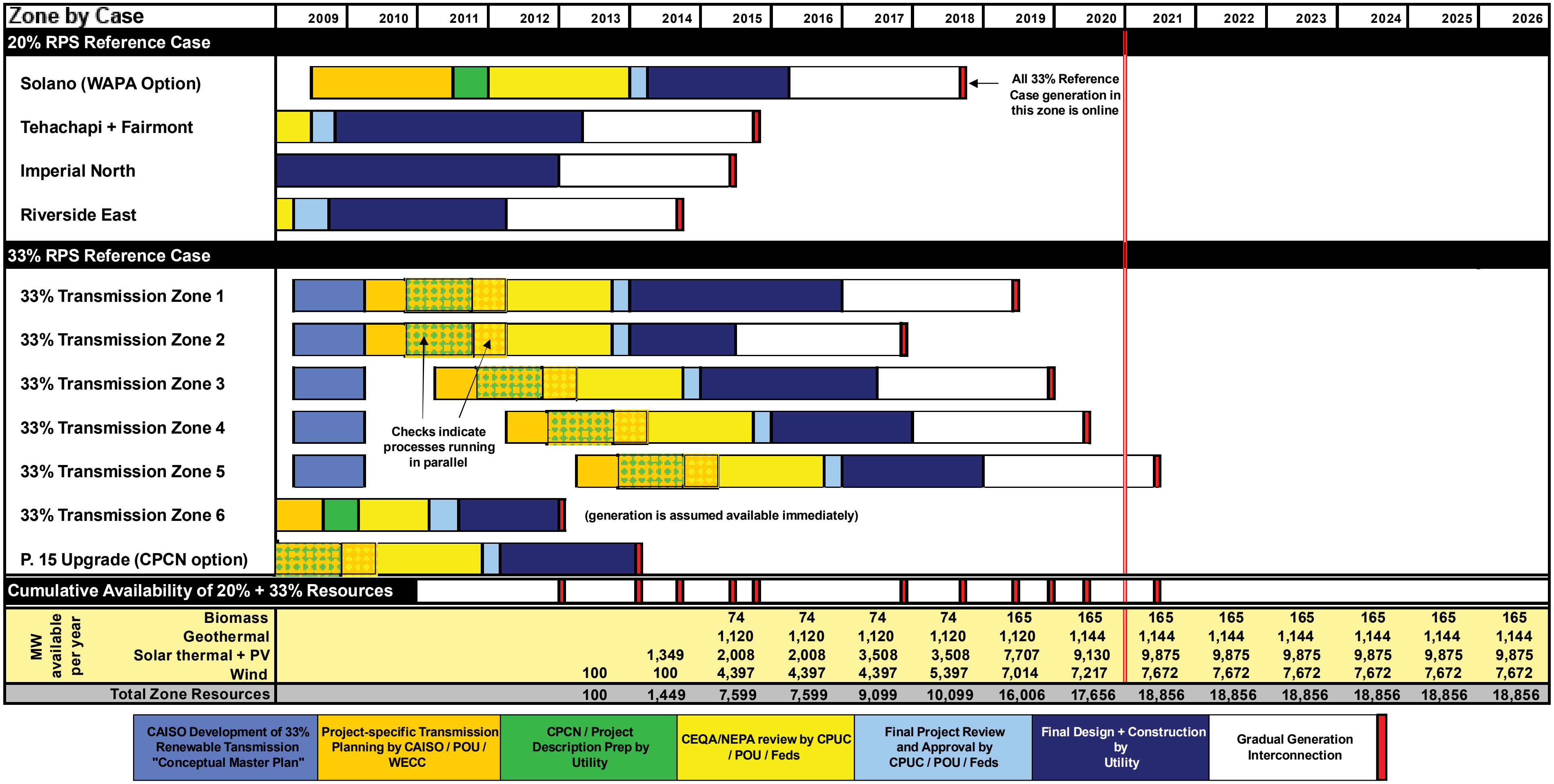
Implication: Efforts underway to reform generation and transmission planning and permitting processes could significantly speed the rate at which California is able to achieve a 33% RPS.

Figure 8. Illustrative Timeline 2A for the 33% RPS Reference Case: Current Practice With Process Reform and No External Risks



Source: CPUC/Aspen

Result: The 33% RPS Reference Case is achieved in 2021, assuming no external risks that could result in delay.

DESCRIPTION OF REFORMS EMBEDDED IN TIMELINES 2A AND 2B

Development of the generation and transmission infrastructure required for a 33% RPS could be achieved by 2021 with the successful implementation of the significant process reforms discussed here, assuming there are no external delays – those outside the direct control of the state. California planning and permitting entities must give high priority to process improvements today. Given the long lead times needed to develop transmission and generation projects, a delay of even a year or two may hinder the state's ability to reach its renewable goals in time.

Reform 1: Improvements to California ISO Procedures for Interconnecting Generation Facilities

The California ISO has recently implemented two very important reforms that will help expedite generator interconnection to the transmission grid. The Generation Interconnection Process Reform (GIPR) has increased the speed and efficiency of studying interconnection requests by planning common transmission solutions for groups of generation projects and integrating such planning into the California ISO annual transmission planning process. In addition to projects in the "serial" study group[37] that are nearing study completion, GIPR intends to complete its first set of interconnection cluster studies by the second quarter of 2010, which will help clear much of the existing transmission interconnection request backlog. The California ISO's new Location-Constrained Resource Interconnection process is the second reform that is expected to help renewable generators. This process provides a framework for planning and sharing the costs of large transmission facilities that interconnect location-constrained renewable resource areas. In May 2009, the California ISO applied this cost-sharing mechanism for the first time to an interconnection that will access renewable generation in the Tehachapi wind resource area.

- The GIPR and Location-Constrained Resource Interconnection reforms contribute to the 2-year planning process assumed in Timelines 1, 2A, and 2B.

Reform 2: Streamlining Transmission Permitting

The siting of a transmission line includes the review required under the California Environmental Quality Act (CEQA) – at least one full year of environmental studies – as well as a determination that the line is needed, through the issuance of a Certificate of Public Convenience and Necessity (CPCN). The CPUC is working to streamline all aspects of this process, while considering fully the environmental and economic impacts of any proposed project.

CEQA Review

In 2006, the CPUC issued directives[38] that streamline the pre-filing, post-filing, and proceeding phases of the transmission permitting process. CPUC staff makes use of streamlining tools such as project-specific memoranda of understanding with federal agencies and mitigated negative declarations whenever possible. In 2008, CPUC staff prepared streamlining recommendations to address and clarify the complex mitigation issues associated with permitting and constructing new transmission. In 2009, the CPUC initiated a series of workshops to be held every 6-9

[37] The "serial group" consists of generation projects that, for a number of reasons, continued in the serial study process that characterized the interconnection process prior to the adoption of the Generation Interconnection Process Reform's cluster study approach.

[38] ftp://ftp.cpuc.ca.gov/puc/energy/environment/060713_transmissionprojectreviewstreamliningdirective.pdf

months with state and federal resource agencies to facilitate better coordination on permitting, considering staffing shortages and increasing workloads. Further, through close coordination during the pre-filing phase, CPUC staff aims to streamline the CPUC's environmental review by ensuring that all the requisite information, and no duplicative work, is provided with the CPCN application. Utility responsiveness and cooperation is critical to the success of these staff efforts. Finally, the CPUC is investigating new technologies that might reduce the environmental impact of necessary transmission infrastructure, thereby reducing public opposition and the risk of delay.

- Successful application of these reforms is illustrated in the reduction in the time assumed for CEQA/ National Environmental Policy Act (NEPA) review from 24 months in Timeline 1 to 18 months in Timelines 2A and 2B.

Need Determination

In addition to CEQA review, the CPUC has a statutory obligation to examine the "need" for any proposed transmission line, and during the CPCN application process the CPUC has carried out this "need determination" in parallel with its CEQA review. Typically, the California ISO has made a finding of need before a project reaches the CPUC under its Federal Energy Regulatory Commission-approved tariff and North American Electric Reliability Council/WECC reliability standards. This evaluation considers reliability, economic, and operational benefits of proposed transmission upgrades to California ISO ratepayers. This analysis is conducted in the California ISO's Transmission Planning Process.

In a 2006 decision, the CPUC adopted a procedure by which the CPCN process could be streamlined by granting, under certain circumstances, a presumption of reasonableness to the California ISO's need determination. The CPUC and California ISO are currently working together to refine and streamline this procedure and the overall permitting process by improving the coordination of their respective transmission review and approval processes in a number of ways, including alignment of the alternatives that are considered in the California ISO's economic and the CPUC's environmental analyses. The improvements under consideration will expedite the "need determination" required for transmission applications by coordinating the processes of the CPUC and the California ISO to reduce gaps and redundancies in the current process. Such coordination aims to reduce the amount of time involved in determining the need for a transmission line, reduce the risk of legal challenges of that determination, and reduce the amount of time involved in planning the lines and preparing CPCN applications.

- Successful coordination on "need determination" is reflected in Timelines 2A and 2B by the overlap between application development, environmental review, and transmission planning – resulting in savings of 12-18 months – and by the reduction of "final approval" from 4-5 months to 3 months. This coordination could also prevent additional delays due to legal challenges of need determinations.

Reform 3: Streamlining Generation Permitting

The Energy Commission and other state and federal agencies involved in permitting and siting renewable generation projects have taken several steps that may help to streamline their review of renewable generation facilities. In August 2007, the Energy Commission and the BLM signed a memorandum of understanding in order to conduct a joint environmental review of renewable projects that fall under both of their jurisdictions. The BLM is also developing a programmatic environmental impact statement for solar facilities, and the Governor's Executive Order S-14-08 directs the Energy Commission and the Department of Fish and Game to conduct programmatic environmental review of renewable generation in the Colorado and Mojave Deserts. This work will help to identify areas in the desert where renewable generation might cause the least environmental harm, and would help to facilitate the permitting of solar facilities in those areas.

The work will also consider the impact of transmission necessary to deliver those renewable resources to load, and may help to streamline the environmental review of those transmission lines. While this reform is very important, it does not improve existing resource and staff constraints at these agencies, which must be addressed if streamlining of the generation permitting process is going to be successful. See Table 11 for a summary of the number of renewable generation projects each agency would need to process under the 33% RPS Reference Case.

- While Timelines 2A and 2B do not change the 30 month transmission-generation time lag assumption, they do account for generation streamlining by assuming no increase in processing time, even given the magnitude of new projects that would require generation permits at approximately the same time.

Reform 4: The Renewable Energy Transmission Initiative

RETI will help reduce the amount of time needed to develop plans of service for transmission lines. Specifically, RETI stakeholders are developing conceptual transmission lines and prioritizing line segments that the California ISO will review immediately under its detailed planning process in 2009-2010. RETI's efforts to involve a broad range of stakeholders at the federal, state, and local levels early in the planning process may also mitigate delays later in the process, especially in the CPCN approval process.

- RETI's efforts are reflected in the assumption in Timeline 2A and 2B that two new transmission projects enter the development process in 2010, rather than the one new project per year assumed in Timeline 1.

Reform 5: California ISO Planning for Renewable Resources in 2010 Transmission Planning Process

In the third quarter of 2009, the California ISO plans to issue a conceptual transmission plan based on the results of Phases 1 and 2 of RETI. This study, which will be informed by the first results from the GIPR study process, will be a conceptual master plan for achieving a 33% RPS by 2020 and will allow the California ISO to efficiently design a reliable transmission system for California and the WECC. This plan will go before the California ISO Board in the first quarter of 2010, along with the California ISO's 2010 Transmission Plan.

During 2010, the California ISO will begin the Large Project stakeholder study processes for the highest priority components of its conceptual master plan, followed by further projects in subsequent years. In order to ensure the development of a reliable transmission system, built in a least-cost manner, the California ISO has indicated that the planning for the transmission needed for a 33% RPS must be staged through at least 2014. The order in which projects enter the stakeholder study process is a critical question that will be informed in coming months and years by RETI, GIPR, the Long-Term Procurement Plans, and other processes, largely in the context of the California ISO's Annual Transmission Planning Process.

- The California ISO's plans are reflected in the addition of the "conceptual master plan" to Timelines 2A and 2B, and the staged planning of individual renewable transmission projects through the first quarter of 2015.

> **Implication:** Transmission planning is a time-intensive process, and the California ISO's estimation of the time required to plan transmission for a 33% RPS is a key driver of the Timeline 2A and 2B results. Thus, successful execution of the California ISO's plan – beginning with the study planned for completion in September 2009 – is crucial.

Reform 6: Transmission Corridor Designation

The federal government and the state have recently enacted legislation to require designation of transmission corridors. Designation of such corridors can help streamline environmental review of transmission facilities proposed within those corridors, and can minimize stakeholder concerns, provided that stakeholders were fully engaged in the designation process. The federal government has identified numerous corridors in California, and the CPUC anticipates that these corridor designations will be extremely valuable in permitting new transmission facilities. The legislature has also directed the Energy Commission to identify transmission corridors in California, and the Energy Commission may initiate corridor designation for some of the paths that RETI identifies as valuable in the longer-term. *Once corridors are identified, an important next step is to secure the ability to use those corridors, perhaps through the purchase of high-priority corridors.*

- Corridor designations contribute to the reduction of the CEQA/NEPA review time from 24 months in Timeline 1, to 18 months in Timelines 2A and 2B.

ILLUSTRATIVE TIMELINE 2B: CURRENT PRACTICE WITH PROCESS REFORM AND EXTERNAL RISKS

As noted, Timeline 2A is not a realistic timeline, since it assumes no external development risks cause delay to generation or transmission projects. Experience indicates that large infrastructure projects can be delayed for many reasons. In the case of renewable energy infrastructure, many of these risks, such as technology, financing, and permitting risk, can be identified, but not necessarily predicted. See the text after Figure 9 for more discussion of these external risks.

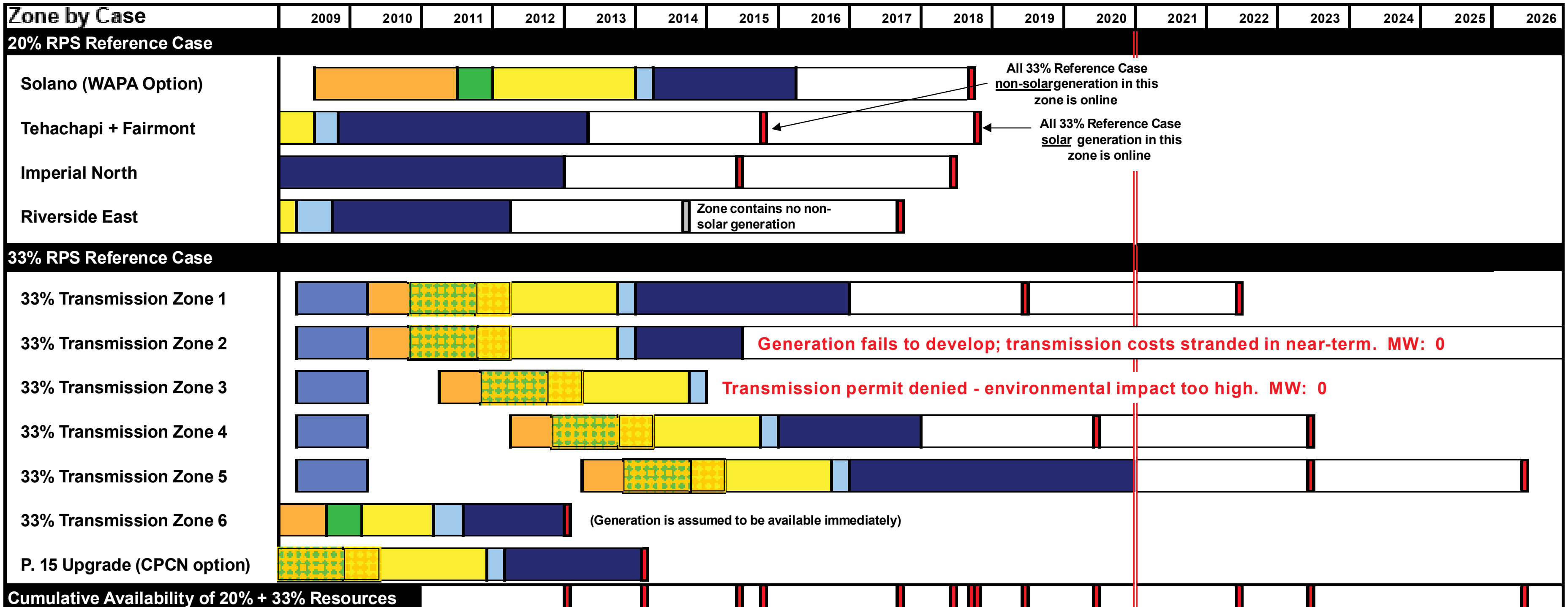
In Timeline 2B, "current practice with process reform and external risks," (Figure 9) the state encounters numerous project development delays that undermine the reforms identified in Timeline 2A. As a result, the 33% RPS Reference Case is not achieved. *The specific time delays shown in Timeline 2B, and the zones to which those delays are assigned, represent one possible scenario, given the risks that are known today*. There are several specific reasons that achievement of the 33% RPS is hindered in Timeline 2B:

- All timelines and reforms in Timeline 2A are assumed in Timeline 2B, but negative outcomes to several external risks now facing the state are realized. Timeline 2B maintains the assumption from Timeline 2A that there are no resource constraints in processing transmission and generation permitting applications.
- Generation in one zone fails to develop, resulting in new transmission capacity that goes unused in the near-term (stranded costs).
- Transmission to one zone is denied its permit because of environmental concerns or other opposition.
- Construction of the last transmission project is delayed by two years due to workforce and human resource constraints or the inability to finance the project.
- Solar projects throughout California take three years longer to develop than previously anticipated due to financing difficulties, performance failure, permitting difficulties, or other factors.[39]
- The outcomes above, and their implications for the 33% RPS time horizon, are not fully realized until 2014 and later. New generation and transmission development would likely begin to replace the failures/major delays, but 2014 may likely be too late to change course for a 2020 deadline. This analysis did not consider the addition of "replacement zones" to the 33% RPS Reference Case or procurement strategies not dependent on new transmission.

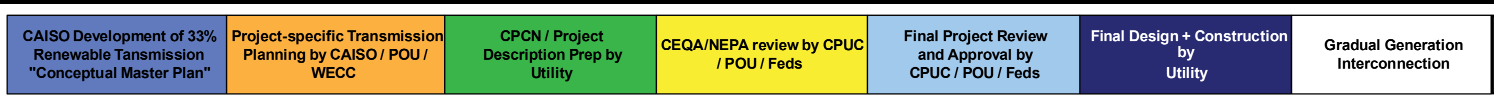
Implication: California's current procurement path is focused almost solely on central station renewable generation that is dependent on new transmission. In order to mitigate the risk that one resource zone would fail to develop, delaying the achievement of a 33% RPS by several years, the state should implement a procurement strategy that adequately considers the time and risk, in addition to price, associated with particular renewable generation resources. The state may also wish to adopt risk mitigation strategies, such as planning for more transmission than needed to reach just 33%, pursuing procurement that is not dependent on new transmission, or other solutions.

[39] This assumption is not particularly pessimistic, given the large number of solar thermal projects in the 33% RPS Reference Case relative to capacity installed worldwide to date (see Figure 14). Timeline 2B still assumes the interconnection of nearly 5,000 MW of solar thermal resources over the course of about 6 years.

Figure 9. Illustrative Timeline 2B for the 33% RPS Reference Case: Current Practice With Process Reform and External Risks



MW available per year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Biomass							74	74	74	74	165	165	165	165	165	165	165	165
Geothermal							1,120	1,120	1,120	1,120	1,120	1,144	1,144	1,144	1,144	1,144	1,144	1,144
Solar thermal + PV									1,349	2,008	2,008	2,008	2,008	4,556	5,979	5,979	5,979	6,724
Wind					100	100	4,397	4,397	4,397	5,397	6,208	6,411	6,411	6,411	6,866	6,866	6,866	6,866
Total Zone Resources					100	100	5,591	5,591	6,940	8,599	9,501	9,728	9,728	12,276	14,154	14,154	14,154	14,899



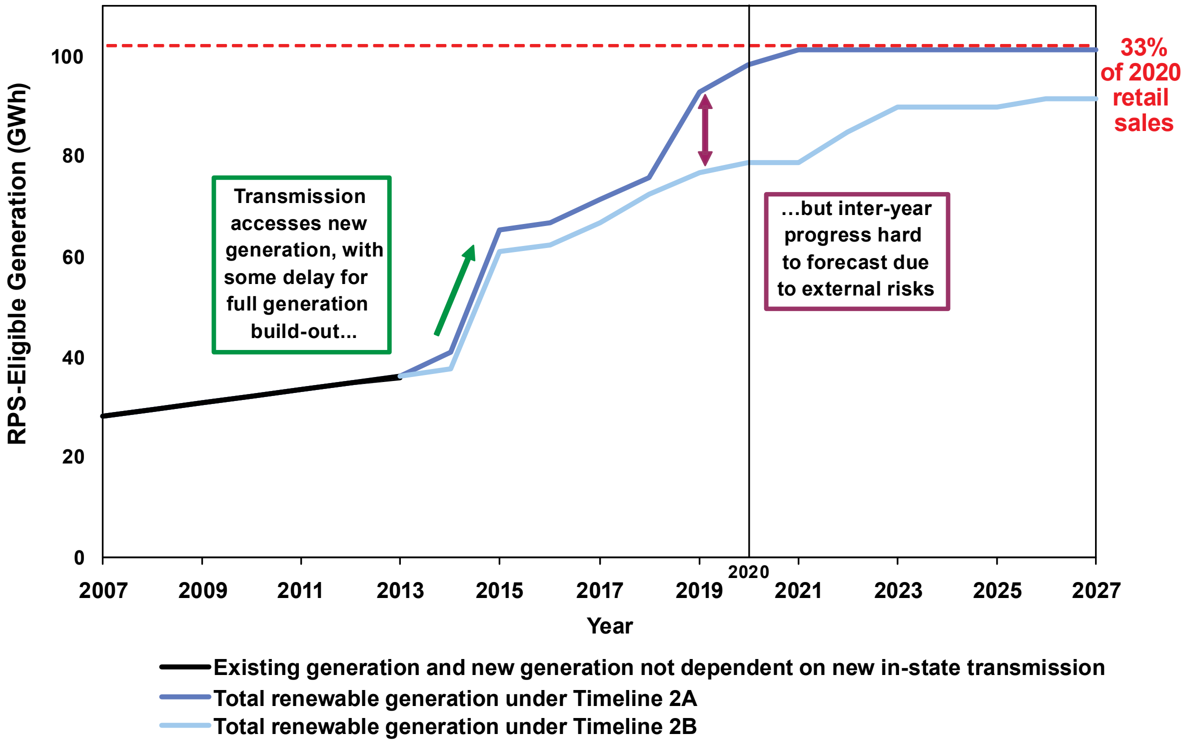
Source: CPUC/Aspen

Result: The 33% RPS Reference Case is not achieved due to unexpected problems with the development of two zones and delays in deployment of large-scale solar projects. Regardless of the nature of the risks that may actually occur, realization of any risk could cause delay and have a significant impact on timing. Although the state does not have direct control over many of the risks facing renewable energy development, it could adopt strategies that would mitigate specific risks.

ANNUAL RENEWABLE GENERATION BUILDOUT

The uncertainty around the external risks that are modeled in Timeline 2B makes it difficult to predict the renewable buildout on a year-to-year basis. Figure 10 illustrates the difference in the year-to-year progress achieved in Timelines 2A and 2B. This figure shows that administrative reforms speed up the renewable resource buildout, but inter-year progress is difficult to forecast due to external risks.

Figure 10. Annual Renewable Generation Buildout for Timelines 2A and 2B



Source: CPUC/E3

Implication: 33% RPS legislation should provide flexibility around annual targets or compliance rules due to the uncertainty around the renewable resource buildout year-to-year.

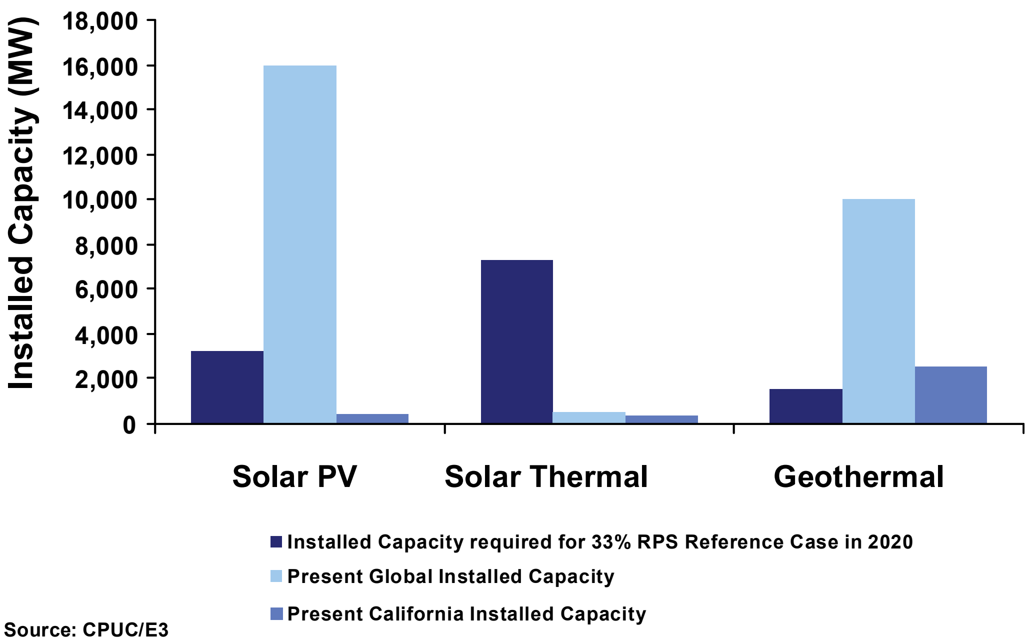
EXTERNAL RISKS THAT COULD DELAY 33% RPS RENEWABLE BUILDOUT

Below, some of the external risks that affect renewable energy development are described in more detail. These risks are outside the direct control of state agencies, and are included in Timeline 2B.

Reliance on New Technologies and Companies

Solar thermal and large-scale solar PV are promising technologies that show significant potential for providing reliable renewable power at competitive prices over the long-term. Solar technology participation in California's renewable energy solicitations has sharply increased in recent years, and the state's utilities are signing and negotiating thousands of megawatts of contracts for utility-scale solar power. The 33% RPS Reference Case includes over 7,000 MW of proposed solar thermal projects and over 3,000 MW of proposed solar PV. These new and emerging technologies, however, face some of the highest risks in terms of project viability. Unlike on-shore wind energy, and to a lesser degree geothermal energy, some solar thermal and solar PV technologies are not yet deployed widely on a utility-scale. Figure 11 shows the global installed capacity of solar PV, solar thermal, and geothermal resources as of 2008 to the right of the quantity of resources required to meet the 33% RPS Reference Case.

Figure 11. Global and Statewide Installed Capacity Versus Installed Capacity of 33% RPS Reference Case in 2020[40]



Source: CPUC/E3

[40] Wind is excluded from this chart to maintain scale. There was more than 121,000 MW of worldwide global installed wind capacity in 2006, compared to about 10,000 MW assumed in California in 2020 in the 33% RPS Implementation Analysis. Global Installed capacity numbers are from the "Renewables Global Status Report 2009." The California installed capacity for solar PV and solar thermal are from the Energy Commission's Energy Almanac. The installed capacity for geothermal is from the Geothermal Energy Association's website. All numbers are through 2008.

As indicated in Figure 11, there is currently only about 500 MW of solar thermal capacity installed worldwide. The 7,000 MW of solar thermal included in the 33% RPS Reference Case would represent a 14-fold increase in global installed capacity. Both solar PV and geothermal technologies have been installed around the world in quantities exceeding those required to meet the 33% RPS target in California by 2020. However, the 33% RPS Reference Case would require increasing worldwide installed solar PV and geothermal capacity by about 15%, relative to 2008 levels. Likewise, the High DG Case includes about 15,000 MW of solar PV; this represents nearly a doubling of global solar PV capacity in California over the next 10 years, which is in addition to strong solar PV demand in other countries.

Reliance on technologies untested at this scale is risky. The primary risk is that relatively new solar thermal technologies will not be able to operate at utility-scale. Furthermore, assuming that each new technology ultimately does reach commercialization, there is still substantial risk that unanticipated technical hurdles will delay projects and prevent the necessary solar resources from coming online by 2020. A variation of this scenario is reflected in Timeline 2B: solar resources are assumed to require five years longer to develop than anticipated in Timeline 1. It should also be noted that technological breakthroughs for renewables could occur, but past experience indicates that these breakthroughs would need to occur nearly immediately in order to influence a 2020 timeline.

In addition to technology risk, many renewable energy technologies are evolving rapidly and the changing nature of the renewable energy sector means that clear market leaders have not emerged from among the many renewable energy developers. Over the next several years, it is likely that a number of these companies will fail as companies with superior technologies or better access to capital gain market share. This level of uncertainty in the market represents both a risk and an opportunity for California. It is a risk because not all of the state's renewable energy contracts are likely to result in commercially operational projects by 2020. On the other hand, it is an opportunity, since California's investment in renewable energy today is likely to further development of the renewable energy market overall. This highlights the tension between meeting the 33% RPS goal by 2020 and furthering long-term market transformation. If California values long-term market transformation, then a strategy that relies heavily on emerging technologies could accomplish that goal. However, this strategy will be less likely to achieve the 2020 target than a strategy that relies only on mature technologies.

Implication: California's high reliance on relatively new technologies and companies risks achievement of the 33% RPS in 2020. A planning process that allows balancing of time, risk, and cost associated with renewable development should provide opportunities for emerging technologies to demonstrate commercialization at projected costs without compromising stated policy goals.

Generation and Transmission Financing

Table 13 shows the estimated amount of capital investment required to construct all of the facilities selected in the 20% and 33% RPS Reference Cases. This figure includes the costs of new transmission lines as well as new renewable and conventional generating facilities needed to meet the RPS target and serve load reliably. Building the generation and infrastructure necessary to reach the 20% RPS Reference Case requires almost $52 billion of capital, while achievement of the 33% RPS Reference Case is estimated to require more than twice as much, approximately $115 billion. These numbers do not reflect the net costs to the ratepayers, but rather the amount of investment capital that will be needed to finance a 20% or 33% RPS.

Table 13. Cumulative Statewide Capital Investment Required Through 2020 Under the 20% and 33% RPS Reference Cases (billions of 2008 dollars)

	20% RPS Reference Case	33% RPS Reference Case
New Renewable Generation	$32.8	$95.3
New Transmission	$4.0	$12.3
New Conventional Generation	$15.0	$6.9
Total Capital Investment Required	***$51.8***	***$114.5***

In light of the magnitude of the capital investment required to achieve the state's RPS goals and serve load reliably, the current economic downturn poses another risk to the achievement of the state's 33% RPS goal by 2020. As credit availability has tightened in 2009, some companies are finding it harder to raise the capital they need to develop renewable generation and transmission projects. In addition, many of the newer renewable technology companies are still actively seeking venture capital, which is less plentiful than in recent years.

Some of the financing challenges may be mitigated in the short term by the American Recovery and Reinvestment Act (ARRA) of 2009 that President Obama signed into law on February 17, 2009. However, it is unclear to what extent ARRA is a solution given that these projects must begin construction in the next two years if they are to benefit from these new federal provisions. Moreover, tightened credit requirements are likely to be a long-lasting legacy of the current financial crisis, which may make it more difficult and expensive for renewable project developers to obtain financing for projects needed to achieve a 33% RPS by 2020.

Implication: Achieving a 33% RPS by 2020 is projected to require almost $115 billion of total investment, which is more than double the estimated $52 billion investment needed to reach the 20% RPS. If investors are going to provide the capital, they will need to have a high degree of confidence in specific renewable projects, in the ability of the California ISO and utilities to construct the needed transmission to integrate the renewable resources into the California grid, and in the willingness of policymakers to allow utilities to recover the costs from ratepayers.

Environmental Impacts

New renewable projects and transmission lines may create a range of significant and long-lasting environmental impacts. Many impacts may be reduced through engineering, design, and the use of careful construction practices. Other impacts are likely to remain significant and potentially unavoidable. Specifically, renewable projects using wind and solar technologies involve especially large areas: a single solar project can cover as much as 10,000 acres of land, about one-third of the total land area of San Francisco, completely converting the land to energy production.

Environmental impact analyses for new large renewable generation projects are now under way. The Energy Commission and BLM are reviewing applications for solar projects using different solar thermal technologies and local agencies are reviewing projects of large-scale wind and solar PV technologies. The completed analyses demonstrate that these projects have the potential to create a range of significant and long-lasting environmental impacts.

Some of the environmental impacts that can result from large renewable generation facilities, which are now being studied in an attempt to develop appropriate mitigation, are the following:

- A permanent loss of habitat for protected wildlife species and special status plants would occur. The availability of adequate mitigation land to compensate is uncertain, especially for expansive solar projects.
- Large projects would create blockage of wildlife corridors, potentially constraining or eliminating important linkages between sensitive population groups.
- Birds and bats can collide with wind turbines if located in areas with notable or threatened avian populations.
- A permanent change in the visual character of open spaces or agricultural areas would occur, inserting large expanses of industrial features to previously uninterrupted vistas. Desert views would also be affected by glare from the mirrors and towers used in some solar thermal technologies. Wind turbines would alter hilltop and ridgeline views.
- Limited supplies of groundwater would be used for regular cleaning of thousands of mirrors and panels for solar installations.
- Public lands in the desert would be converted from open space, available for multiple uses such as recreation, mining, and grazing, to a single exclusive purpose – power generation.
- A cumulative loss of resources would occur as the impacts above are realized throughout California – especially in the desert, where over 100 projects are already proposed.

Implication: Environmental permitting agencies will face difficult choices in the years ahead, as they struggle to balance environmental conservation and renewable and GHG emission reduction goals. Such choices, made in the context of permit applications for individual generation and transmission projects, will greatly affect the date by which the state can achieve a 33% RPS.

Legal challenges and public acceptance of environmental impact

Permitting agencies must weigh carefully the environmental and economic benefits associated with proposed renewable generation projects and transmission lines, against the environmental harm done by such extensive infrastructure development. The process of approving generation and transmission projects can be delayed as a result of public opposition or associated legal challenges. While no transmission line approval granted by the CPUC has been successfully challenged in court in the past 15 years, most projects are met with increasing amounts of public opposition. New transmission lines needed to deliver remote renewable resources would likely range in length from 20 to 200 miles, and large-scale renewable development in desert areas would also require transmission upgrades within most of the coastal metropolitan areas to deliver the energy to loads. Transmission lines in these areas face property and right-of-way constraints and have traditionally faced substantial public opposition.

Public opposition to local, Energy Commission, and BLM approvals of large renewable generation projects also appears to be increasing. The public and various interest groups have raised particular concerns about the scale and magnitude of large-scale solar projects in the desert. Projects currently proposed in the Southern California desert would each cover 3,000 to 10,000 acres depending on technology and generation capacity, and over 70 of these projects have filed applications with the BLM on nearly 700,000 acres. While not all of these projects will ultimately be needed or constructed, the 33% RPS Reference Case would include construction of roughly 30 large solar projects in the Southern California desert, which could result in the environmental impacts described above. Valid concerns about such impacts, as well as NIMBY (Not In My Back Yard) concerns, may be raised in the permitting process and lead to delay or even denial of permits.

Implication: Public opposition to large-scale renewable energy infrastructure could delay or halt progress towards a 33% RPS. RETI works to reduce opposition by involving stakeholders early in the development process, but the state may also consider other options for reducing the risk of public opposition, including different procurement strategies or concentrated renewable development in one or more renewable energy parks. Tradeoffs in terms of resource quality and price may be warranted if it appears that development in more cost-effective areas faces too great a risk of delay.

5 Summary of 33% RPS Cases

This section shows how the 33% RPS cases perform against the various policy goals and objectives of a 33% RPS, based on the results described in Sections 3 and 4. Through a number of executive orders and state law, state policymakers have articulated numerous policy goals and objectives for achieving a 33% RPS, which are outlined in Section 1. In this section, quantitative and qualitative analysis of the performance of alternative strategies is presented for meeting a 33% RPS in addressing state policy goals and objectives. Table 14 depicts these findings.

CASE OVERVIEW

Commonalities among all the cases:

All of the 33% RPS cases result in GHG emission reductions similar to those established by the ARB in its Scoping Memo. As mentioned previously, GHG emission reductions are measured based on the emissions reduced during generation. A lifecycle GHG analysis was beyond the scope of this analysis. The 33% RPS cases also perform equally well in reducing reliance on fossil fuels and increasing resource diversity. As demonstrated through the natural gas and CO_2 allowance price sensitivity analysis, all of the 33% RPS cases provide a hedge against fluctuating natural gas prices, but at a relatively high cost.

Differences among the cases:

Each of the 33% RPS cases has a different impact on ratepayers. While a detailed implementation analysis was not conducted on any of these alternative strategies, the timing does seem to differ across the cases since different technologies have different construction durations and transmission needs. As for development risk, different technologies face different risks, depending on whether the technology is emerging or commercially proven.

The cases may differ in terms of economic impacts as well. All cases result in higher electric rates, reducing disposable income for California consumers. However, renewable infrastructure construction, operations, and maintenance result in some local job creation, depending on how much of the infrastructure is located in California. Regardless of where the project is located, economic benefits could accrue to California if renewable companies establish their operations in California. Lastly, local environmental quality differs across the cases since different technologies have different land and air quality impacts.

33% RPS Reference Case (current IOU procurement strategy)

- *Cost Impact:* 7.1% cost premium compared to the 20% RPS Reference Case. Most expensive case relative to other alternative 33% RPS cases except for the High DG Case.
- *Economic Development:* More in-state jobs compared to the High Out-of-State Delivered Case.
- *Local Environmental Quality:* High reliance on large-scale solar technologies could decrease local environmental quality due to land impacts, but high reliance on in-state generation could displace existing fossil fuel generation and reduce local air and water pollution.
- *Timing:* High reliance on central station renewable resources, which require new transmission, suggests a higher likelihood of delays.
- *Development Risk*: Many external risks, such as reliance on new, unproven technologies could delay the 2020 target beyond the transmission delays.
- *Long-Term Market Transformation:* Reliance on new solar technologies could lead to future cost-reductions and technology breakthroughs.
- *Conclusion:* This case is most likely to miss the 2020 target timeline due to the amount of significant transmission required and its heavy reliance on new, unproven technologies. This case does excel in long-term market transformation.

High-Wind Case

- *Cost Impact*: 4.1% cost premium compared to the 20% RPS Reference Case.
- *Economic Development*: Case results in similar in-state job creation to 33% RPS Reference Case, and lower rates means higher disposable personal income.
- *Local Environmental Quality:* Wind technologies have both positive and negative effects. Wind has a smaller land footprint compared to solar, but can lead to bird mortality. In addition, wind technologies could require a greater amount of fossil generation to backup the generation during non-peak hours, which could decrease local air quality.
- *Timing:* Wind technologies have a shorter development period compared to other renewable technologies, which could facilitate achievement of a 33% RPS by 2020. On the other hand, wind technologies also need new transmission.
- *Development risk:* Less of a concern for wind since the technology is mature.
- *Long-Term Market Transformation:* Wind technologies contribute less to long-term market transformation since the technology is mature.
- *Conclusion:* This is a cost effective way of achieving a 33% RPS, but is likely to miss the 2020 timeline because of the amount of transmission required. While it performs reasonably well with the other policy categories, it does not excel in any of them.

High Out-of-State Delivered Case

- *Cost Impact:* 3.8% cost premium compared to the 20% RPS Reference Case.
- *Economic Development:* This case creates fewer in-state jobs compared to the 33% RPS Reference Case due to a higher reliance on out-of-state resources; however, lower rates mean higher disposable personal income.
- *Local Environmental Quality:* Greater reliance on out-of state resources could preserve sensitive lands in California, but out-of-state resources may not help improve local air quality since local fossil resources may still have to run for resource adequacy purposes.
- *Timing:* Out-of-state resources may have shorter development timelines since much of the out-of-state development is focused on wind, but a high reliance on new, multi-state transmission line development adds risk.
- *Development risk:* Less of a concern for out-of-state resources since wind and geothermal are mature technologies.
- *Long-Term Market Transformation:* Wind and geothermal technologies contribute less to long-term market transformation since the technologies are mature.
- *Conclusion:* Of the cases studied, this case provides the lowest cost strategy to achieve a 33% RPS, although the cost is not much less than the High Wind Case. High reliance on multi-state transmission introduces an element of risk into the 2020 timeline. This risk could be mitigated through tradable RECs with no delivery requirement, which would also lower the cost of out-of-state resources. This case does not perform well on the other policy preferences.

High Distributed Generation Case

- *Cost Impact:* 14.6% cost premium compared to the 20% RPS Reference Case. This cost is substantially higher than the 33% RPS Reference Case and alternative 33% RPS cases since this case relies on distributed generation, primarily solar PV, to fill the 33% RPS resource needs.
- *Economic Development:* Could create more jobs than the other cases since rooftop PV is labor intensive; however, California electricity expenditures would be nearly $4 billion higher than the 33% RPS Reference Case, which would lead to lower economic development and job growth for other businesses overall.
- *Local Environmental Quality*: Performs well since case minimizes transmission and maximizes rooftop installations. It can also improve local air quality by displacing in-state local fossil generation.
- *Timing:* Could perform well on timing and could assist meeting the 33% RPS in 2020, though transaction costs and potential supply constraints to meet the high number of installations make timing uncertain.

- *Development risk:* Such large amounts of solar PV on the distribution grid could create grid reliability problems, which could slow development. In addition, this strategy would require nearly a doubling of global solar PV capacity, which could lead to supply chain constraints, affecting the timing.
- *Long-Term Market Transformation:* Case could benefit medium-term market transformation of the solar PV market and lead to future cost-reductions.
- *Conclusion:* A high DG strategy could facilitate achieving a 33% RPS in 2020 as well as mitigate some of the need for transmission and transform the market for solar PV technologies. However, less is known about the feasibility of this case, including the willingness of building owners to rent their rooftops, impacts on grid reliability, effectiveness of utility programs and other delivery channels, and whether both manufacturing capacity and a trained workforce will be available to meet this large increase in demand. This case has the highest cost unless there are significant cost breakthroughs in solar PV technologies.

Table 14. Comparison of 33% RPS Cases Across RPS Policy Objectives[41]

Policy Objective	33% RPS Reference Case	High Wind Case	High Out-of-State Delivered Case	High-DG Case
Cost	◒	●	●	○
Timing	○	◒	◒	◒
GHG Emission Reductions	●	●	●	●
Resource Diversity	●	●	●	●
Local Environmental Quality Air Quality	●	◒	○	●
Local Environmental Quality Land Use	○	◒	◒	●
Economic Development	◒	◒	○	◒
Long-Term Transformation	●	○	○	●
Technology Development Risk	○	●	●	○

Legend:

● Case performs well ○ Case performs poorly ◒ Case is neutral

[41] This study only preformed an implementation analysis on the 33% RPS Reference Case. Thus, evaluation of other cases for all criteria (except for cost and GHG reductions) is based on a qualitative analysis drawing from over seven years of experience in implementing the RPS program.

6 Findings

The purpose of this report is to provide new and in-depth analysis on the cost, timing, and risks of a 33% RPS for the State of California. This report does not recommend a preferred strategy on how to reach a 33% RPS, but rather provides an analytical framework for policymakers to understand the tradeoffs inherent in any 33% RPS program for California. The analysis also highlights the need to prioritize different policy objectives as well as the need to start considering mitigation strategies to lesson the effects of delay from external risks.

KEY FINDINGS OF THIS REPORT

Achieving a 33% RPS will require tradeoffs between various policy goals and objectives

There are multiple strategies the state could pursue to reach a 33% RPS, but each portfolio will have different cost impacts, reach the 33% RPS target at a different date, and perform differently across the broad list of stated policy goals and objectives. For example, the results of this analysis show a relationship between timing and the maturity of various technologies. Specifically, using proven technologies increases the chances of reaching the target date of 2020, while relying on new technologies decreases the chances of making the target date. This relationship is evident in the current procurement strategies that the California IOUs are pursuing. The IOUs are currently signing multiple contracts with solar thermal projects, which reflects risks inherent to the emerging nature of the technology, including higher prices and performance risk. While this strategy has the potential for long-term market transformation, it risks high costs and failure to meet the 33% RPS in 2020.

Table 15 provides four examples that illustrate how a specific policy priority results in different renewable procurement strategies. A "Least-Cost" policy priority, for example, demonstrates a preference for low-cost renewables, most likely from outside of California. The "2020 Timeline" policy priority focuses on achieving a 33% RPS by the fixed deadline of 2020, with a high reliance on commercialized technologies and high levels of DG, while "In-State Jobs" priority relies most heavily on procurement strategies that will lead to the most in-state job development. "Market Transformation" relies heavily on developing market transformational technologies such as solar thermal, but also contains the highest risk of missing the 2020 deadline. Each of these policy-driven procurement strategies also demonstrates the tradeoffs that would have to be made in terms of the other policy preferences and objectives.

Table 15. Sample Renewable Procurement Options Based on Policy Priorities

Least-Cost Renewables	2020 Timeline
Procurement Priority: 1. In-state development of lower-cost resources and commercialized technologies, such as wind and biomass.[42] 2. Least-cost renewable energy delivered to California, including construction of new interstate transmission lines. 3. Procurement of out-of-state renewable energy facilitated through tradable RECs with no delivery requirement. *Cost*: Lowest *Timing*: 2020 likely since the lower cost resources also have shorter development periods. Based on program experience, out-of-state resources can be built faster than in-state resources. *Market Transformation:* Low as there is heavy focus on existing technology.	*Procurement Priority:* 1. Near-term renewable energy projects in California, with focus on commercial technologies that do not need new transmission, such as DG. 2. Viable out-of-state resources delivered to California over existing transmission. 3. Procurement of out-of-state renewable energy facilitated through tradable RECs with no delivery requirement. *Cost*: Medium High *Timing*: 2020 likely because of high reliance on existing transmission, existing technologies, and high DG. *Market Transformation:* Medium low, since there is heavy focus on existing technology, although it could contribute to solar PV price reductions.
In-State Jobs[43]	**Market Transformation**
Procurement Priority: 1. High focus on in-state renewables including both high and low cost renewables and those that require new in-state transmission. *Cost*: Highest - higher rates could have unintended consequences and lead to job loss in other sectors. *Timing*: Post 2020 likely, but heavy focus on DG could help mitigate the time lag of potential transmission bottlenecks and potential permitting issues. *Market Transformation:* Medium high if there is a mixture of new and existing technologies.	*Procurement Priority:* 1. Emphasis on emerging, likely higher-cost renewables, such as solar thermal, with significant transformational benefits. *Cost*: Medium High *Timing*: Post 2020, highest risk due to technology uncertainty. *Market Transformation:* Highest due to significant investment in new technologies.

These priority portfolios show that a low-cost strategy may be able to achieve a 33% RPS by 2020 using commercial technologies and out-of-state resources. However, a strategy that prioritizes mostly in-state development or market transformation will cost more and take more time to achieve. Given the large number of contracted solar thermal resources and current

[42] These numbers do not include a full study of renewable integration costs. As a result, the relative cost of this strategy could change once Phase 3 is complete, including California ISO analytical input.
[43] Only accounts for jobs directly resulting from RPS.

emphasis on in-state development, the 33% RPS Reference Case more closely reflects the "In-State Jobs" and "Market Transformation" procurement options described in Table 15. It is important to note that the IOUs are procuring at a very aggressive rate and it is expected that they will be at or close to a 33% RPS on a contract basis in the near future. As a result, the state may be already beyond the point where a purely "least-cost" strategy could be adopted.

California must start implementing mitigation strategies if a 33% RPS by 2020 is the most important policy priority

Timeline 2B provides an example of a scenario in which, despite successful implementation of ambitious reforms, two resource zones fail to develop due to external risks. While Timeline 2B presents a hypothetical example, it illustrates the potential impact of real risks that California's current procurement strategy is not prepared to mitigate. Specifically, California's current procurement path is focused almost solely on central station renewable generation that is dependent on new transmission. In order to mitigate the risk that one resource zone would fail to develop, delaying the achievement of a 33% RPS by several years, the state should consider a procurement strategy that adequately considers the time and risk, in addition to price, associated with particular renewable generation resources. The state may also wish to adopt risk mitigation strategies, such as planning for more transmission and generation than needed to reach just 33%; pursuing procurement, such as distributed solar photovoltaics (PV), which is not dependent on new transmission; or concentrating renewable development in pre-permitted land that would be set aside for a renewable energy park.

OTHER FINDINGS

The magnitude of a 33% RPS is unprecedented and will require nearly a tripling of renewable electricity in the next 10 years

To meet the current 20% RPS by 2010 target, four major new transmission lines are needed at a cost of $4 billion. To meet a 33% RPS by 2020 target, seven additional lines at a cost of $12 billion would be required. The 33% RPS target is projected to require an increase from 27 terawatt hours (TWh) of delivered renewable energy today to approximately 75 TWh in 2020.

Electricity costs will be higher in 2020 compared to 2008, regardless of whether California mandates a 33% RPS or not

Even if California makes no further investments in renewable energy, the analysis projects that average electricity rates per kilowatt-hour will rise by 16.7% in 2020 compared to 2008. In 2020, the total statewide electricity expenditures of the 20% RPS Reference Case is projected to be 2.8% higher compared to the all-gas scenario. The total statewide electricity expenditures of the 33% RPS Reference Case is projected to be 7.1% higher compared to the 20% Reference Case, and 10.2% higher compared to the all-gas scenario.

Several critical process reforms have been implemented or are in the early stages of development and implementation that can help speed achievement of a 33% RPS

These reforms will help increase the pace of renewable development. Even under very optimistic assumptions and after the process reforms have been implemented, the 33% RPS target by 2020 is highly ambitious. This is due to the risk from external factors and the magnitude of the infrastructure that California will have to develop, procure, and integrate in the next 10 years.

A 33% RPS could theoretically serve as a potential hedging strategy against volatile fossil fuel prices, but only if natural gas and CO_2 price allowances are very high

In theory, an increase in renewable penetration decreases the range of electricity expenditures by decreasing exposure to volatile fossil fuel prices. While a 33% RPS can provide this hedge, it only provides an effective hedge under very high natural gas and CO_2 prices. Thus, the "hedging value" from resource diversity is not a very strong justification for establishing a 33% RPS.

The interplay between energy efficiency achievement and renewable energy procurement highlights the need to analyze and plan for interactions among the state's various policy goals

Under a low-load scenario that could result from successful implementation of energy efficiency and other demand-side programs, the 20% Reference Case results in substantial capacity savings. On the other hand, the 33% RPS Reference Case results in less incremental capacity savings, which means that a 33% RPS will create capacity that is not needed to serve load, resulting in excess costs to consumers. This finding highlights the need to analyze interactions among the state's various GHG reduction programs. An integrated approach that considers both supply side and demand side programs is needed to ensure that the various programs result in a resource plan that furthers the underlying policy objectives of a comprehensive GHG reduction strategy.

Dramatic cost reductions in solar PV could make a solar DG strategy cost-competitive with central station renewable generation

Under the Solar PV Cost Reduction sensitivity, the total costs of the High DG Case are very similar to the costs of the 33% RPS Reference Case. The solar PV industry is predicting dramatic cost reductions in the coming years even though solar PV is currently the most expensive renewable technology studied in this report. Solar PV on the distribution system has numerous advantages, which include avoiding transmission and land use if sited on rooftops. However, even if solar PV technology costs drop dramatically, the deployment costs associated with thousands of megawatts of distributed PV could still be a challenge. In addition, capturing these megawatts could require a policy mechanism different from the RPS. More analysis is necessary to determine the programmatic strategies necessary to achieve a high-DG scenario as well as the feasibility of high penetrations of solar PV on the distribution grid.

RPS OBJECTIVES SHOULD BE PRIORITIZED

As this analysis has shown, many of the policy objectives are mutually exclusive and in conflict with one another. Currently, the RPS procurement process is effectively dictating the timing, cost, and policy objectives of a future 33% RPS program. Thus, the tradeoffs are being decided through the utility procurement process, not by the policymakers or regulators. Using current RPS contracts as an example, market transformation and in-state economic development are the primary policy objectives that are being prioritized at the expense of meeting a 2020 timeline and minimizing customer costs. This results from lack of having a stated priority preference. Some of the key questions to help determine a priority preference include:

- Should California focus public investment and system planning efforts on developing and integrating technologies with significant long-term transformational potential such as solar thermal or solar PV?
- Should California focus on developing in-state resources? Up to what cost? What is the correct balance between in-state economic development and higher customer costs?
- Is California willing to delay the 2020 target in order to develop primarily California resources and stimulate new technologies and market transformation?
- Should California waive renewable energy delivery requirements for out-of-state resources if it is necessary to meet the 2020 target or pursue a lower cost strategy?
- Should the CPUC encourage the utilities to procure increased amounts of (currently) high-cost solar PV to mitigate the potential negative impact of delay due to failure of a resource zone?

NEXT STEPS

This report captures the preliminary results and conclusions from Phase 1 and Phase 2 of the 33% RPS Implementation Analysis. Phase 3, which CPUC staff intends to finalize by the end of 2009, will integrate the California ISO's renewable integration analysis, RETI and the California ISO's conceptual transmission plans, and the Energy Commission's analysis of once-through cooling fossil plant retirements. In addition, CPUC staff will attempt to identify and articulate possible solutions to many of the risks and challenges identified throughout this report.

As stated previously, the study team did not perform an implementation analysis of the High Wind, High DG Case, or the High Out-of-State Delivered Case. Further analysis of the High Wind Case could help understand potential challenges to developing high levels of wind energy in California and other states. An implementation analysis of the High DG Case could help better understand the costs, reliability impacts, and barriers to implementing such large amounts of solar PV on the distribution grid. For the High Out-of-State Delivered Case, more analysis could help identify possible challenges to developing out-of-state resources and delivering them to California.

Lastly, given the findings from the low-load sensitivity, more analysis could help better understand the interplay between retiring fossil resources, achievement of the aggressive demand-side goals, and a 33% RPS.

Appendix A: List of Acronyms

Acronym	Definition
AB	Assembly Bill
AB 32	(California) Assembly Bill 32 – Global Warming Solutions Act of 2006
ARB	(California) Air Resources Board
ARRA	American Recovery and Reinvestment Act
Aspen	Aspen Environmental Group
BLM	Bureau of Land Management
California ISO	California Independent System Operator
CCGT	Combined Cycle Gas Turbine
CEQA	California Environmental Quality Act
CHP	Combined Heat and Power
CPCN	Certificate of Public Convenience and Necessity
CPUC	California Public Utilities Commission
CO_2	Carbon Dioxide
CREZ	Competitive Renewable Energy Zone
CSI	California Solar Initiative
DG	Distributed Generation
DR	Demand Response
EE	Energy Efficiency
ED	Energy Division
EIR	Environmental Impact Report
E3	Energy and Environmental Economics
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
GIPR	Generation Interconnection Process Reform
GW	Gigawatt
GWh	Gigawatt-hour
IEPR	Integrated Energy Policy Report
IOU	(Large) Investor-Owned Utility
IRRP	Integration of Renewable Resources Program
ISO	(California) Independent System Operator
ITC	Investment Tax Credit
kWh	kilowatt-hour
LTPP	Long-Term Procurement Plans
MMBtu	Millions of British thermal units
$MMTCO_2E$	Millions of Metric Tons of Carbon Dioxide Equivalent
MPR	Market Price Referent
MW	Megawatt
MWh	Megawatt-hour
NEPA	National Environmental Policy Act
NIMBY	Not In My Backyard
PEA	Proponent's Environmental Assessment

Acronym	Definition
POU	Publicly-Owned Utility
PPA	Power Purchase Agreement
PTC	Production Tax Credit
PV	Photovoltaic
REC	Renewable Energy Credit
RETI	Renewable Energy Transmission Initiative
RFO	Request For Offer
RPS	Renewables Portfolio Standard
SB	Senate Bill
TWh	Terawatt-hour
W-e	Watt equivalent

Appendix B: Methodology

STUDY STRUCTURE

Study team and stakeholder process

The consultant study team was comprised of E3, Plexos Solutions (Plexos), and Aspen Environmental Group. Plexos conducted production simulation model runs to provide variable costs and GHG emissions. Although not part of the study team, Black and Veatch contributed to this effort by calculating the availability of rooftop space in urban areas as well as rural lands for siting solar PV projects, in addition to its contributions to the RETI work. CPUC Energy Division staff assisted the consultant team throughout the study period.

The 33% RPS Implementation Analysis Working Group and Transmission Constrained Working Group also contributed to this analysis. Energy Division formed these working groups after a 33% RPS workshop in August 2008. The working group members contributed significantly to this analysis through meetings, data submittals, written comments, and informal discussions. More specifically, the Implementation Analysis Working Group helped develop the 33% RPS Implementation Analysis Work Plan and the Transmission Constrained Working Group contributed to the development of the High DG Case. The working group met in December 2008 and January 2009 to review the study's initial analysis and preliminary results and provided valuable feedback and guidance to the study team.

Study Phases

This study has three phases, which are described below:

Phase 1: August 2008 – December 2008

In Phase 1, the study team utilized data from RETI and other data sources to compile the cost and location of renewable resources available throughout the West. The team also developed an environmental scoring method that built upon RETI's efforts. This information was used to develop resource zone rankings to select draft portfolios for each of the 20% and 33% RPS cases presented below. Stakeholders also provided comments on the 33% RPS cases developed during this phase.

Phase 2: December 2008 – May 2009

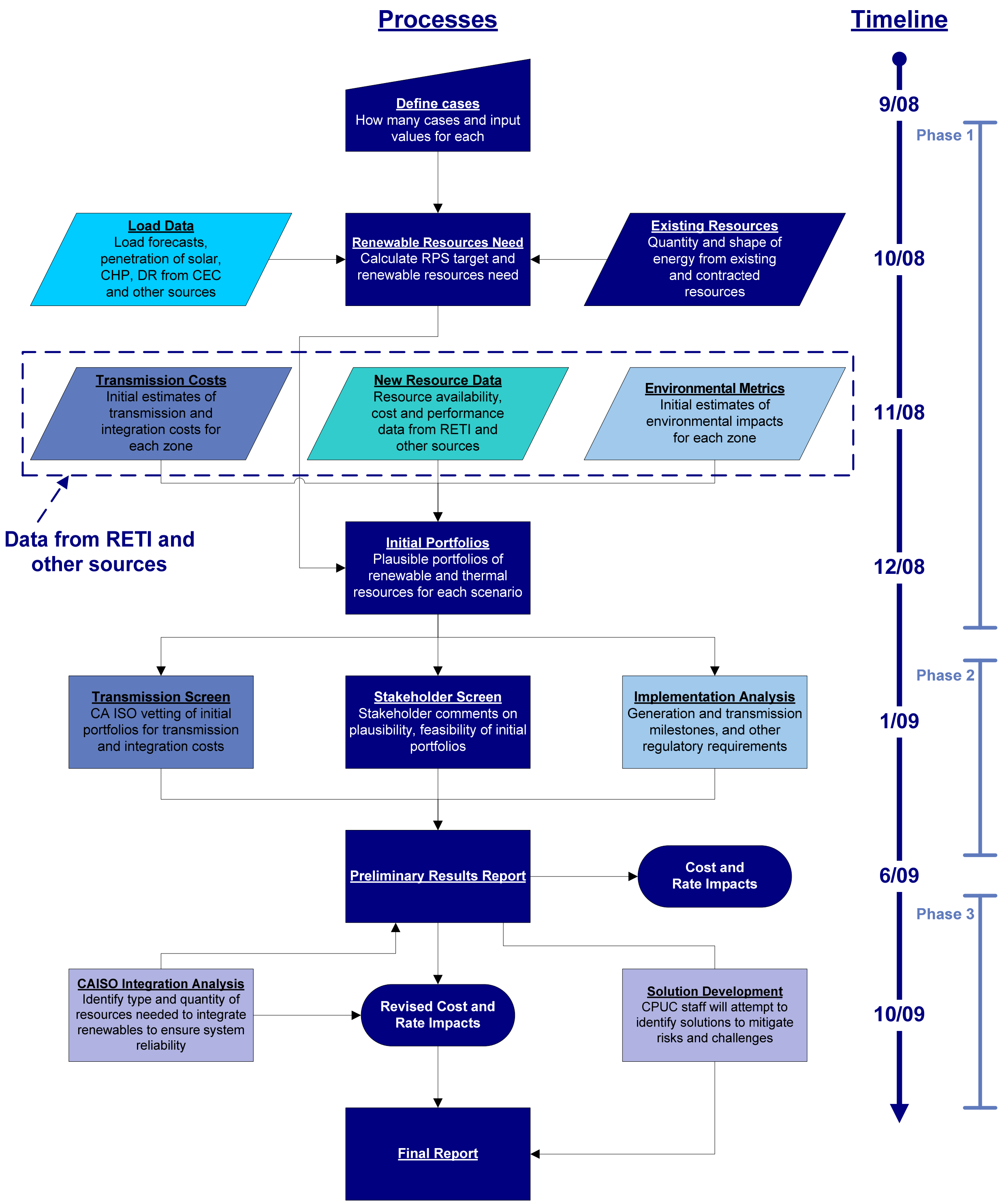
In this phase, the draft portfolios were refined based on stakeholder feedback. Production simulation model runs for the 20% and 33% RPS Reference Cases were conducted to determine the variable costs and GHG emission reductions, and the results were then used to assess the costs and GHG emissions for the alternative 33% RPS cases. The team also analyzed historical generation and transmission development and constructed timelines to illustrate the steps necessary to build new transmission and renewable energy projects in California. This report is the final deliverable of this phase.

Phase 3: April 2009 – Fourth Quarter 2009

The California ISO will identify the type and quantity of resources needed to reliably integrate the 33% RPS resource portfolios that were developed in Phase 2 of this study. Studies on once-through cooling retirements are expected to be completed in the next six months, which will also help inform the quantity and timing of new resources needed to integrate intermittent renewable resources. Based on these analyses, the study team will refine assumptions about the quantity and cost to integrate intermittent renewable resources into the grid.

In addition, RETI and the California ISO will finalize the conceptual transmission plans needed to reach a 33% RPS during the summer of 2009, which will identify the transmission buildout and cost needed to reach a 33% RPS. This will be incorporated into the analysis. Finally, CPUC staff will attempt to identify solutions to mitigate or overcome the risks and challenges identified in this analysis. The final deliverable of this study is the final report, currently scheduled for fourth quarter of 2009.

Figure 12. 33% RPS Implementation Analysis Study Flow Chart Depicting Phases 1-3



Source: CPUC/E3

METHODOLOGY TO CONSTRUCT RENEWABLE RESOURCE PORTFOLIOS

As described above, Phase 1 of this analysis focused on developing initial resource portfolios for each of the 20% and 33% RPS cases, which are composed of specific renewable projects. The study team assembled resource portfolios to meet a 33% RPS target and estimated cost impacts using the RPS Calculator. This section describes in more detail the methodology for constructing these renewable resource portfolios.

RPS Calculator

The RPS Calculator[44] is a Microsoft Excel spreadsheet model developed to aggregate the renewable cost and performance data and select renewable resources needed to meet the RPS target. The model also identifies transmission investments that deliver renewable resources to load and conventional resources that are needed to meet energy and peak demand growth, and calculates the cost and GHG impacts of a given portfolio of resources in 2020.

Renewable Resources Needed by 2020

The analysis starts with a statewide calculation of the renewable resources that California utilities must procure between 2008 and 2020 to meet a 33% RPS by 2020. The resources needed are calculated as the total required quantity of renewable energy in 2020 (33% of retail sales) minus the actual renewable generation that was claimed by California utilities in 2007.

To fill this renewable resource need, the study team gathered the best available data on renewable energy project development and renewable resource potential in California and throughout the West, and used the RPS Calculator to select portfolios of renewable resources.

Renewable Portfolio Data Sources

The analysis relied on four primary sources of data regarding renewable energy costs, resource potential, and commercial interest, each of which provided a level of granularity and accuracy that distinguishes this study from previous analyses. See Section 3 for a description of each data source.

1. CPUC Energy Division project database (ED Database) [45]
2. Renewable Energy Transmission Initiative[46]
3. The GHG Calculator[47]
4. Estimates of distributed renewable energy potential[48]

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[44] The RPS Calculator can be found on the CPUC RPS website: http://www.cpuc.ca.gov/renewables

[45] The CPUC maintains a public version of this database: http://www.cpuc.ca.gov/NR/rdonlyres/F07E249B-C36A-4A38-8D36-BDB88CDB154B/0/RPS_Project_Status_Table_1st_Quarter_2009.xls

[46] Renewable Energy Transmission Initiative: http://www.energy.ca.gov/reti/documents/index.html

[47] As part of its GHG modeling, E3 developed estimates of the cost and performance of renewable resources throughout the Western Interconnection based on data provided by NREL and Energy Information Administration. Detailed descriptions of the methodology can be found on E3's GHG modeling website: http://www.ethree.com/CPUC_GHG_Model.html

[48] Black and Veatch assisted this analysis by estimating large rooftop acreage in urban areas throughout California.

It should be noted that there may be some overlap and duplication of potential projects in the resource supply curves. In addition, renewable energy projects that came online in late 2007 and 2008 may not be represented in a few of the cases. Finally, while the analysis incorporates project information from IOU solicitations, it does not include information about new and projected municipal and cooperative utility renewable energy projects. These slight inaccuracies are insignificant enough that they should not affect the results of the cost and timeline analyses in any meaningful way.

Distributed Renewable Energy Potential

As mentioned above, this analysis includes original estimates of the technical potential to develop and interconnect renewable generation at the distribution level, which are included in all of the 33% RPS cases. Estimates in this study were based on a three screens: 1) the ability to 'easily' interconnect, 2) suitable sites, and 3) willing customers. The first screen was based on an analysis of peak load served by each distribution feeder on the IOUs' systems. Available interconnection capability was then allocated among multiple distributed resource types including solar PV, biogas, biomass, and CHP. The second screen was based on GIS[49] mapping conducted by Black and Veatch for RETI and for this analysis. The third screen is based on simple rules of thumb. In addition to the urban solar PV projects that one normally thinks of as "distributed," this study also included an estimate of 20 MW ground-mounted solar PV systems in rural areas based on the RETI assessment. Since few of these rural systems are expected to meet the 'easy' interconnection criteria, an increased cost of interconnection was incorporated.

Table 16. Screens and Criteria to Estimate Urban Solar PV Potential

Screen	Criteria
'Easy' Interconnection	Peak PV output < 30% of peak load at point of interconnection, and PV location within 3 miles of substation. Available capacity was allocated among distributed resource types.
Suitable Sites	In urban areas, available large roof area (greater than 0.5 acre flat roof) multiplied by 65% usable space. In rural areas, available land with low slopes near substations
Willing Customers	Participation assumed for 1/3 of the sites identified as "suitable sites" with 'easy' interconnection

Table 17 shows the statewide technical potential for each distributed resource used in the High DG Case.

[49] Geographic Information System

Table 17. High Level Distributed Renewable Technical Potential

Technology	Type	Capacity (MW)	Notes
PV	Large Roofs (> 0.5 acre)	3,810	Based on satellite imagery
PV	Small Roofs	2,224	One third of remaining 'easy' connection potential
PV	Ground Mounted	2,266	One third of remaining 'easy' connection potential
PV	Ground Mounted (> 30% of peak load at point of interconnection)	9,000	Exceeds the size for 'easy' connection and gets a cost penalty of $68/kW-year
Biogas	Distribution Connected	249	
Biomass	Distribution Connected	34	
Total		**17,583**	

Defining Renewable Resource Zones

A resource zone is an aggregation of renewable projects by geographic location, technology type and/or resource quality. The resource zones were adopted from RETI and the GHG Calculator are organized around clusters of projects in defined geographic locations. For these zones, this study assumes that a new transmission "trunk line" must be constructed in order to deliver the energy to load centers. Other "zones" may include projects that are not geographically connected, but which do not need transmission and share other similar characteristics that allowed them to be grouped together for computational simplicity. These include "distributed"[50] and out-of-state projects in the CPUC Database and the RETI database.

Determining Resource Portfolio Costs and Rankings

All costs are expressed in 2008 dollars, unless noted otherwise. With the exception of the Solar PV Cost Reduction Case, this study is confined to existing renewable technologies and assumed constant technology costs over the study period. This study did not attempt to predict breakthroughs in technological development or changes in capital or operational costs. In addition, high-level estimates of transmission costs and renewable integration costs were based on a literature review. The California ISO is developing a full network model of the 33% RPS Reference Case, which can be used to improve the transmission cost estimates. The California ISO will also provide an estimate of the resources needed to reliably integrate intermittent technologies. This information will be used to update the 33% RPS cost information in Phase 3 of this analysis.

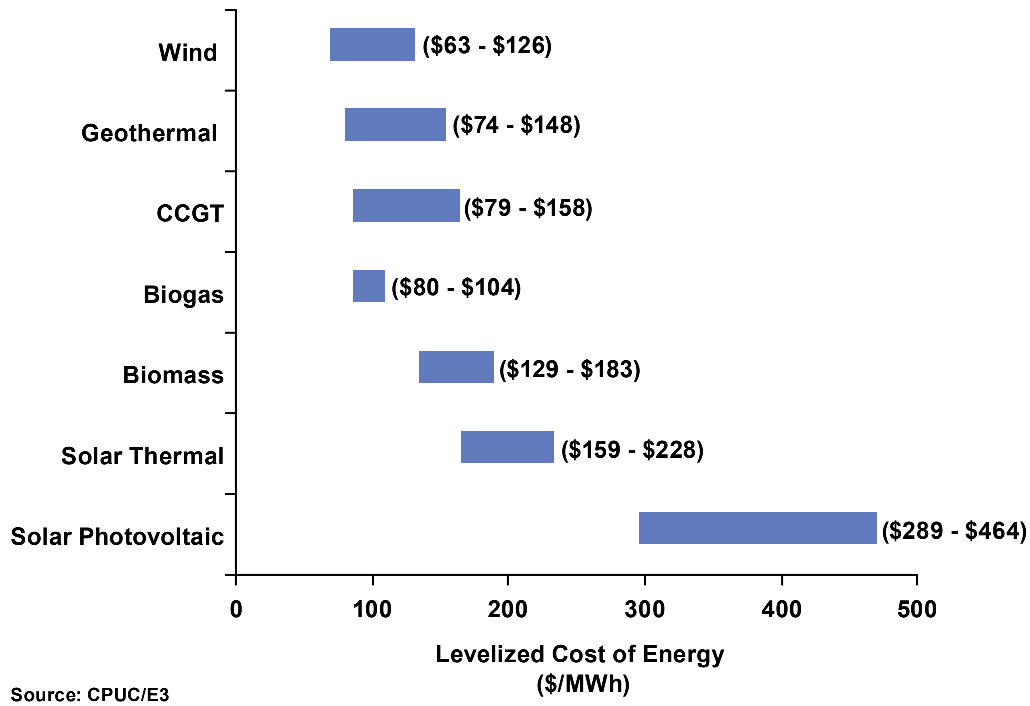
Estimates of the cost of constructing new renewable resources relied primarily on RETI data, which includes cost and performance information for hundreds of potential projects throughout

[50] In this context, "distributed" means simply projects that do not need large new transmission trunk lines in order to interconnect and deliver their energy to load.

California. This represents tens of thousands of megawatts of renewable development. The GHG Calculator contains characterizations of resources that RETI did not analyze, including biogas and small hydro. Based on these resource characterizations and assumptions about project finance, the RPS Calculator outputs a levelized cost of energy that represents the developer cost for each project used for project ranking. Figure 13 shows the resulting developer cost ranges ($/MWh) for each renewable technology considered in this analysis, along with a CCGT benchmark. The solar PV costs are for crystalline PV that is ground-mounted with single-axis tracking.

The project costs do not represent the negotiated contracted price. For most of the projects, the costs are the developer costs to build and operate the project with a reasonable profit. The exception to this assumption is renewable projects that cost less than the cost of a CCGT. These renewable projects were assumed to be at least as expensive as a CCGT since it is unlikely that developers will agree to supply power to California utilities at below the market rate for new conventional resources. This assumption has a modest, upward impact on the total cost of complying with a 33% RPS.

Figure 13. Developer Levelized Cost of Generation by Technology Type[51]



Source: CPUC/E3

[51] This analysis assumes a 20-year PPA with an independent developer. Costs are expressed in 2008 dollars. The renewable technology costs within each technology vary due to project size and location. The CCGT costs vary by natural gas prices.

Determining project value based on avoided costs and environmental scoring

Using the data sources described above, projects are ranked using a modified version of RETI's "net value" approach. The net value is the developer cost of energy from the renewable resource minus the value the resource provides. This value includes avoided energy costs, avoided capacity costs, and avoided GHG allowances purchases. This analysis placed a heavy emphasis on projects that either have a PPA or are in negotiations with a California IOU based on demonstrated commercial interest by treating developer costs as "sunk"[52] for ranking purposes.

In addition to using the avoided costs to rank projects, the study team also determined an environmental score for each project. Starting with the RETI Environmental Working Group's assessment, a project scoring system was developed that considers five additional environmental permitting risk factors, which are described below. This composite environmental metric aims to discern individual projects that may have the fastest or the slowest environmental permitting timelines. After totaling the five factors, projects with the lowest scores are associated with the lowest permitting risk and fastest permitting timelines. Each of these five risk categories was converted into a cost factor to incorporate into the RPS Calculator.

Table 18. Environmental Permitting Risks Factored into Renewable Project Rankings

Factor	Description
Factor 1: All RETI Environmental Issues	Captures total ranking score of each renewable resource zone that the RETI Environmental Working Group defined.
Factor 2: Transmission Footprint	Emphasizes the constraint new transmission line right-of-way represents since the permitting of new transmission lines can be especially time-consuming and challenging.
Factor 3: Pre-Identified versus Proxy Projects[53]	Since proxy projects lack a project sponsor, they are likely to take substantially longer to permit than the "pre-identified projects" that have been developed by specific project developers.
Factor 4: Proximity to Sensitive Lands	Captures visual and aesthetic impacts (views from sensitive lands are generally the highest priority for protection), cumulative impacts, and public opposition. Siting of generation or transmission near sensitive lands generally increases the likelihood of public opposition.
Factor 5: Projects on Federal Land	Federal site permitting can take much longer than the state-only process due to requirements to comply with the NEPA, often in addition to the state CEQA requirements.[54]

[52] These projects are assumed to be available at zero cost for ranking purposes. This ensures that projects with active developer interest are selected first inside each zone, and increases the odds that a zone with active projects is selected. These projects are assigned a cost based on generic resource characterizations when calculating the cost impacts.

[53] RETI identified projects "proxy projects," or projects located in areas with resource potential, even though there was no project sponsor.

[54] It also appears that federal land management agencies are understaffed to handle the significant number of pending (and anticipated) applications for renewable generation and transmission projects, thus the additional consideration of this factor in the scoring system.

Cost Metrics and Sensitivity Analysis

E3 estimated California's annual electricity expenditures in 2020, which is the combined revenue requirement of all of California's utilities (IOU and POU). In addition to the cost of constructing new resources, E3 projected changes in utility costs in a number of areas such as transmission, distribution, fuel costs, and CO_2 allowance price. The result is a projection of California's total electricity expenditures in 2020 under each of the cases. Changes in the state's total electricity expenditures between the 20% RPS Reference Case and the 33% RPS cases represent the incremental costs of complying with a 33% RPS. Sensitivity analysis was then conducted for key variables such as natural gas prices and CO_2 allowance prices, load growth, and solar PV costs.

E3 also calculated the average electricity cost per kWh in 2020, which is the statewide electricity expenditures divided by total retail sales. While this metric is informative, it does not show the bill impact for different customer classes. California's retail rate designs vary for each electric utility in the state, so the bill impacts of achieving a 33% RPS could be somewhat higher or somewhat lower for any individual household or business. For example, the IOU residential rates for lower levels of usage are currently capped at 2001 levels as a result of AB 1X,[55] passed in the immediate aftermath of the California Energy Crisis. This rate cap would last until 2022 under current law, so absent a change to these provisions, the costs of achieving 33% RPS could not be recovered from these sales for lower levels of usage. This would have the effect of increasing the "per kWh" charge, or cost of a 33% RPS that is levied on all remaining usage. As a result, non-residential customers would see proportionately higher bills than they would if all customer usage was billed for RPS costs. A detailed analysis of the distributional impacts of a 33% RPS on customers was beyond the scope of this analysis.

Table 19. Cost Metrics

Metric	Definition
Statewide electricity expenditures in 2020	Combined revenue requirement of all California utilities (IOU and POU)
Average electricity cost per kWh in 2020	Statewide electricity expenditures divided by total retail sales

Development of Renewable Cases

In order to compare the costs of a 33% RPS to existing state policy, E3 created a 20% RPS Reference Case. Next, E3 created a 33% RPS Reference Case, representing primarily the results of recent IOU solicitations, as well as three alternative 33% RPS cases to test different policy objectives. The 33% RPS Reference Case prioritizes all projects that have resulted from recent solicitations (approved, pending approval, or short-listed) and are therefore represented in the CPUC Database. The alternative 33% RPS cases prioritize projects that the CPUC has *approved*, but do not prioritize projects that are *pending approval* or *short-listed*. This results in an additional 39 TWh of energy that can be met through selection of other renewable resources from the RETI and E3 databases.

[55] The CPUC issued D.01-05-064 on May 14, 2001 to implement AB 1X: http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/7185.htm

20% RPS Reference Case

The 20% RPS Reference Case assumes that California utilities procure only enough resources to maintain the current statutory target of a 20% RPS in 2020. This case focuses primarily on resources that can be integrated through new transmission corridors that are already approved by the CPUC or are expected to be added in the near term such as Tehachapi and Sunrise.

33% RPS Reference Case

The 33% RPS Reference Case places the heaviest emphasis on projects in the ED Database, which represent projects that have been short-listed or contracted by IOUs. The 33% RPS Reference Case assumes that most of the projects in that database are developed by 2020. Since IOUs have selected a substantial number of solar thermal and solar PV projects in recent solicitations, these resources are heavily represented in the 33% RPS Reference Case. The case includes 7,200 MW of solar thermal and 3,200 MW of central utility-scale solar PV resources, along with other wind, geothermal, and biomass resources. As such, this case probably represents a high bookend on the amount of solar thermal that could realistically be developed by 2020.

High Wind Case.

The High Wind Case replaces most of the solar resources in the 33% RPS Reference Case with wind resources in California and Mexico. Instead of relying on the higher cost solar thermal resources that are heavily represented in recent IOU solicitations, this case represents the lowest-cost resources that can be developed in-state without assuming major, new interstate transmission.

High Out-of-State Delivered Case

The High Out-of-State Delivered Case assumes that new, long-distance transmission lines are developed to access high-quality renewable resources from out-of-state resources in the WECC. The case includes a 3,000 MW transmission line bringing wind energy from Wyoming and a 1,500 MW transmission line bringing principally geothermal resources from northern Nevada. Like the High Wind Case, this case relies more heavily on wind than solar resources. However, in this case a larger proportion of the wind is anticipated to come from outside of California.

High DG Case

The High DG Case is intended to examine the implications of the state relying heavily on distributed resources such as solar PV to meet a 33% RPS. Motivations for such a case include increasing public opposition to large transmission or generation projects that have long development times, large upfront investments, and environmental complexities. The High DG Case assumes that it would be difficult or impossible to construct new, high-voltage transmission projects to accommodate renewable resources, beyond those lines assumed for the 20% RPS Reference Case. To fill the renewable resource need, this case relies on estimates of the technical potential of solar PV and other distributed renewable resources. It does not fully examine the approaches needed to deploy this case, however.

Table 20. Assumptions in all 2020 Cases

Category	Assumption
Load forecast	Energy Commission's 2007 IEPR reference case or mid-case load forecast
Fuel price forecast	The Market Price Referent methodology, updated with new natural gas prices, was used to develop the base case forecast
CO_2 allowance price forecast	The Market Price Referent methodology was used for CO_2 price forecasts to develop the base case forecast
Energy efficiency achievement	No incremental energy efficiency assumed beyond what is already incorporated in the Energy Commission's 2007 IEPR load forecast
Demand response achievement	No incremental demand response assumed beyond what is already incorporated in the Energy Commission's 2007 IEPR load forecast
Combined Heat and Power (CHP) achievement	Energy Commission 2007 IEPR base-case load forecast assumption for CHP penetration
Customer-installed solar PV	Energy Commission 2007 IEPR load forecast, 847 MW nameplate of customer-installed PV[56]
GHG allowance allocation	GHG emissions allowances are auctioned. Auction revenue from allowances equal to 2008 electricity sector emissions is returned to utilities
Resource characterizations	Reference case resource cost assumptions based on RETI and E3 data for renewable generation and the Market Price Referent[57] for new combined-cycle gas turbines

[56] The 2007 IEPR load forecast assumed 847 MW of customer-side PV, a fraction of the 3,000 MW California Solar Initiative goal.

[57] D.08-10-026 approved the 2008 MPR Methodology. Resolution E-4214 calculated the 2008 MPR based on this methodology. MPR-related documents can be accessed on the CPUC website: http://www.cpuc.ca.gov/PUC/energy/Renewables/mpr

TIMELINE METHODOLOGY

In order to evaluate the feasibility of achieving the 33% RPS Reference Case by 2020, this study determined reasonable timelines for the sequence of steps required to plan, permit, and construct the generation and transmission identified in the 33% RPS Reference Case. This assessment provides a pragmatic "reality check" of the state's ability to reach California's 33% RPS target since it realistically assesses implementation timelines as well as major factors and uncertainties driving those timelines. This study only performed a timeline implementation analysis on the 33% RPS Reference Case since this case represents the IOUs' current procurement strategy. The 33% RPS Reference Case, however, represents only one of many plausible development scenarios that could meet a 33% RPS. In addition, an implementation assessment of the distributed and out-of-state resources that contributed to the 33% RPS Reference Case was not performed.

The study team began its assessment by identifying the key milestones and lead times involved in bringing new transmission and generation online. Distinct sets of milestones were identified for different categories of generation and transmission projects, and the team analyzed empirical evidence as to the timing of the completion of those milestones. Various simplifying assumptions were made, as detailed below. These assumptions result in somewhat optimistic estimates of the time required to develop renewable energy.

Renewable technology assumptions:

- Over the next 10 to 15 years, all currently proposed renewable projects will obtain the necessary financing to construct the project and commence operations
- All of the proposed renewable energy technologies will operate as proposed
- Renewable energy development companies will succeed in bringing all of their projects online
- There will be no manufacturing bottlenecks or other supply chain constraints, which could slow project development

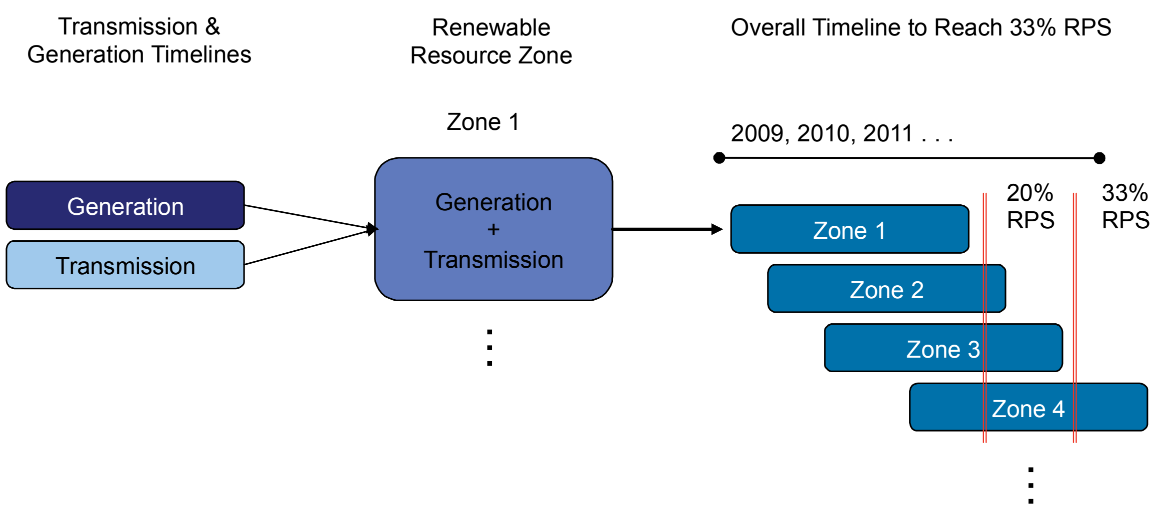
Transmission assumptions:

- The transmission expansions identified are conceptual and are meant to provide a general sense of the number of major new transmission lines and the number of applications for a CPCN or permit application required to access the renewable resources included in the 33% RPS Reference Case. These conceptual expansions have not been subject to detailed transmission planning and project design
- Does not identify additional transmission upgrades that would likely be needed within the study period to accommodate load growth and reliability requirements, and to make the renewable resources included in the 33% RPS Reference Case fully deliverable to load centers
- Transmission lines assumed to be sited within United States BLM utility corridors (if on BLM land) or adjacent to existing transmission lines (if not on BLM land), though distance from existing lines was not estimated

The study team then created generic timelines for the generation and transmission facilities needed to achieve the 33% RPS Reference Case. Once the building blocks of the individual generation and transmission timelines were in place, these individual timelines were combined into one overall timeline for the 33% RPS Reference Case.

Figure 14 illustrates the process of combining the generic transmission and generation timelines into timelines for each resource zone, and subsequently combining the individual resource zone timelines into the three illustrative timelines for achieving the full 33% RPS Reference Case portfolio.

Figure 14. Timeline Development Flow Chart



Source: CPUC/Aspen

Generic generation and transmission timelines

Transmission planning, permitting, and construction require substantial lead times, generally longer than those required for generation facilities. The timelines for transmission and generation facilities are interdependent. The completion date of a new transmission line dictates the earliest possible online date for a generation project that needs that transmission to deliver the energy to load. The relationship between transmission and generation affects a renewable developer's willingness to invest in the project development efforts. Renewable developers will only invest in project development if they believe the required transmission will be available when needed and at a cost suitable for their project's economics. Generation development in any resource zone can occur at the same time that transmission development is occurring for that zone, but generation development may extend beyond completion of the transmission line due to the challenges associated with simultaneously completing the transmission and generation.

Generic Transmission Timeline

The 33% RPS Reference Case assumes the development of seven major generic new transmission lines to the selected resource zones, beyond those new lines already assumed in the 20% RPS Reference Case.

This analysis only identifies and evaluates the large (200 kV and above) transmission lines that require a CPCN from the CPUC or a similar approval from a POU, because of the lengthy review required for such major lines. Several smaller lines would likely be required before 2020 to maintain grid reliability under the 33% RPS Reference Case, but because these lines are generally reviewed and permitted much faster than the large transmission lines, they are not considered to be critical path and are not considered in this analysis.

The typical timeline for new transmission is estimated to be approximately eight years, as shown in Table 21. The transmission planning timeline of 24 months takes into consideration increased efficiencies expected from GIPR[58] currently taking place at the California ISO as well as coordination of interconnection studies with the overall transmission planning process. Although the steps below are shown in sequence, portions of the work often proceed in parallel. Section 4 of this report describes efforts to gain efficiencies in the transmission development process by further coordinating the steps below.

Table 21. Generic Timeline for an IOU-Owned Transmission Line > 200 kV, Based on Past Transmission Permitting Experience

Transmission Development Process	Timing
Transmission Planning Process • ISO interconnection studies/transmission planning and board approval • IOU development of plan of service (may overlap with the above)	24 months
PEA/CPCN Application preparation by IOU[59]	18 months
CEQA/NEPA review and environmental documentation by local, state, and/or federal agency, resulting in an environmental impact statement	24 months
CPUC approval	3 months
Final design and construction	30 months
TOTAL	**99 months (8.25 years)**

[58] GIPR is expected to increase the speed and efficiency of studying interconnection requests by planning common transmission solutions for groups of generation projects and integrating such planning into the California ISO annual transmission planning process.
[59] PEA = Proponent's Environmental Assessment.

While the CPUC averages approximately 18 months for CEQA review and CPCN approval for transmission siting cases in general, more conservative assumptions were used here to account for the likely larger and more controversial nature of these new required projects. For purposes of this assessment, a transmission line is assumed to be 100 miles long, with some segments on federal land, and located entirely within the boundaries of California. The duration of final design and construction varies widely, however, depending on the utility's readiness to move forward with the route that is finally selected. This schedule can be shortened up to three months if the utility were to start preliminary engineering immediately upon issuance of the draft Environmental Impact Report (EIR) since the transmission route usually does not change significantly from the draft to the final EIR.

Generic Generation Timeline

The 33% RPS Reference Case requires the development of nine new resource zones, comprising approximately 19 GW. The analysis suggests that the nine resource zones can be accessed by seven new transmission lines. The typical timeline estimated for renewable resource selection and development is 42 to 93 months (3.3 to 7.8 years), depending on the type of renewable generation. The components of the timeline are shown in Table 22.

Table 22. Generic Renewable Generation Timeline for an IOU-Contracted Resource

Renewable Project Development Process	Timing
Request for Offer issuance and review	3 months
Negotiation of PPA and submittal to CPUC	5-12 months
CPUC review and approval of PPA	4-6 months
Project design, site control, and permit application preparation	12 months on average
Permitting and development: Renewable resource permitting and development, including environmental documentation by municipality, county, Energy Commission, and/or federal lead agency	18-60 months
TOTAL	**42-93 months (3.5 - 7.8 years)**

The permitting and development section in Table 22 includes a range of timeframes for permitting at various agencies and a range of construction durations from under one year for the smallest projects up to multiple years for more complex facilities. The permitting requirements for generation are dictated by technology type, location, and size. There are six categories of generation projects for purposes of permitting, each with a distinct timeline depending on the complexity of environmental permitting and the agencies involved. Similarly, construction durations vary by resource type and size. The timelines in Figure 15 and Figure 16 present estimates of permitting and construction timelines for various categories of generation projects. These timelines represent expected (not minimum or maximum) timelines, and are based on a review of recently developed renewable generation projects. This information was used to aggregate renewable projects in each zone to determine a timeline for each resource zone needed for a 33% RPS.

Figure 15. Standard Permitting Timelines for Categories of Renewable Generation Projects

Project Size & Jurisdiction	Resource Type	Year 1	Year 2	Year 3	Year 4
SMALL - LOCAL	Any renewable (<50 MW)	Application Prep	City / County CEQA		
SMALL - FEDERAL	Any renewable (<50 MW) on Federal land	Application Prep	City / County CEQA Federal Agency NEPA		
LARGE - LOCAL	Solar PV, Wind	Application Prep	City / County CEQA		
LARGE - STATE	Geothermal, Solar Thermal, Biomass, Biogas (> 50 MW)	Application Prep	CEC CEQA Equivalent		
LARGE - FEDERAL + STATE	Geothermal, Solar Thermal, Biomass, Biogas (> 50 MW) on Federal land	Application Prep	CEC CEQA Equivalent Federal Agency NEPA		
LARGE - FEDERAL + LOCAL	Solar PV, Wind	Application Prep	City / County CEQA Federal Agency NEPA		

Source: CPUC/Aspen

Figure 16. Standard Construction Timelines for Categories of Renewable Generation Projects[60]

Resource	Size	Year 1	Year 2	Year 3	Year 4
SOLAR PV	Small (<50 MW)	12 months			
SOLAR PV	Large (>50 MW)		25 months		
SOLAR THERMAL	Small (<50 MW)	16 months			
SOLAR THERMAL	Large (>50 MW)			35 months	
WIND	Small (<50 MW)	13 months			
WIND	Large (>50 MW)		20 months		
BIOMASS, GEOTHERMAL	Small (<50 MW)	12 months			
BIOMASS, GEOTHERMAL	Large (>50 MW)		26 months		

Source: CPUC/Aspen

[60] Timelines can vary greatly within the size ranges presented in the figure, i.e. between a 5 MW and a 49 MW plant, and between a 50 and 500 MW plant. The small number of completed large-scale PV and solar thermal plants also makes it very difficult to generalize construction times; the large solar PV and thermal plants contracted for development in California would be the first projects at that scale globally. The construction duration estimates here are meant to be illustrative.

Appendix C: Resource Zones and Resource Mix for each Renewable Case

RESOURCE ZONES USED IN RPS CALCULATOR

Resource Zone Name	Description or Source
Alberta	GHG Calculator Zone
Arizona-Southern Nevada	GHG Calculator Zone
Baja	RETI Competitive Renewable Energy Zone (CREZ)
Barstow	RETI CREZ
British Columbia	Combination of RETI CREZ/ GHG Calculator Zone
Carrizo North	RETI CREZ
Carrizo South	RETI CREZ
Colorado	GHG Calculator Zone
Cuyama	RETI CREZ
Distributed Biogas	Biogas resources from RETI and E3 that are assumed to be able to come online without substantial new transmission
Distributed Biomass	Biomass resources from RETI that are assumed to be able to come online without substantial new transmission
Distributed CPUC Database	Resources of all types from the CPUC Database that are assumed to be able to come online without substantial new transmission
Distributed Geothermal	Geothermal resources from RETI that are assumed to be able to come online without substantial new transmission
Distributed Solar	Solar resources from RETI that are assumed to be able to come online without substantial new transmission
Distributed Wind	Wind resources from RETI that are assumed to be able to come online without substantial new transmission
Fairmont	RETI CREZ
Imperial East	RETI CREZ
Imperial North	RETI CREZ
Imperial South	RETI CREZ

Resource Zone Name	Description or Source
Inyokern	RETI CREZ
Iron Mountain	RETI CREZ
Kramer	RETI CREZ
Lassen North	RETI CREZ
Lassen South	RETI CREZ
Montana	GHG Calculator Zone
Mountain Pass	RETI CREZ
Needles	RETI CREZ
NE Nevada	GHG Calculator Zone
New Mexico	GHG Calculator Zone
Northwest	GHG Calculator Zone
Not Assigned	Resources listed in RETI database that are a) not assigned to a geographic zone and b) assumed to require new transmission
Owens Valley	RETI CREZ
Out-of-State Early	Out-of-state resources from CPUC database that are either under contract or short-listed and expected to come online in the near term
Out-of-State Late	Out-of-state resources from CPUC database that are either under contract or short-listed and expected to come online in the long term, plus 1,400 MW of additional out-of-state wind resources assumed to be available to California utilities
Palm Springs	RETI CREZ
Pisgah	RETI CREZ
Remote DG	RETI estimates of PV potential modified for RPS Calculator
Reno Area/Dixie Valley	GHG Calculator Zone
Riverside East	RETI CREZ
Round Mountain	RETI CREZ
San Bernardino - Baker	RETI CREZ
San Bernardino - Lucerne	RETI CREZ
San Diego North Central	RETI CREZ
San Diego South	RETI CREZ
Santa Barbara	RETI CREZ

Resource Zone Name	Description or Source
Solano	RETI CREZ
South Central Nevada	GHG Calculator Zone
Tehachapi	RETI CREZ
Twentynine Palms	RETI CREZ
Utah-Southern Idaho	GHG Calculator Zone
Victorville	RETI CREZ
Wyoming	GHG Calculator Zone

RESOURCE ZONE AND RENEWABLE MIX FOR ALL RPS CASES[61]

20% RPS Reference Case

Resource Zones Selected in 20% RPS Reference Case		
	MW	GWh
Tehachapi	3,000	8,862
Distributed CPUC Database	525	3,118
Solano	1,000	3,197
Out-of-State Early	2,062	6,617
Imperial North	1,500	9,634
Riverside East	1,350	3,153
Total	**9,437**	**34,581**

Resource Mix – 20% RPS Reference Case						
	In-State		Out-of-State		Total	
	MW	GWh	MW	GWh	MW	GWh
Biogas	30	223	-	-	30	223
Biomass	241	1,687	87	610	328	2,297
Geothermal	1,240	9,515	58	445	1,298	9,959
Hydro - Small	22	95	15	66	37	161
Solar PV	830	1,774	-	-	830	1,774
Solar Thermal	996	2,431	-	-	996	2,431
Wind	4,016	12,240	1,902	5,497	5,917	17,737
Total	**7,375**	**27,965**	**2,062**	**6,618**	**9,436**	**34,582**

[61] Some of the MW and GWh totals may be off by one digit. This is due to rounding.

33% RPS Reference Case

Additional Resource Zones Selected in 33% RPS Reference Case		
	MW	GWh
Resources from 20% RPS Reference Case	9,437	34,581
Mountain Pass	1,650	4,041
Carrizo North	1,500	3,306
Out-of-State Late	1,934	5,295
Needles	1,200	3,078
Kramer	1,650	4,226
Distributed Biogas	249	1,855
Distributed Geothermal	175	1,344
Fairmont	1,650	5,003
San Bernardino - Lucerne	1,800	5,020
Palm Springs	806	2,711
Baja	97	321
Riverside East Incremental	1,650	3,869
Total	23,798	74,650

Resource Mix – 33% RPS Reference Case						
	In-State		Out-of-State		Total	
	MW	GWh	MW	GWh	MW	GWh
Biogas	279	2,078	-	-	279	2,078
Biomass	391	2,737	87	610	478	3,346
Geothermal	1,439	11,027	58	445	1,497	11,471
Hydro - Small	25	111	15	66	40	177
Solar PV	3,235	6,913	-	-	3,235	6,913
Solar Thermal	6,764	16,652	534	1,304	7,298	17,956
Wind	7,573	22,899	3,399	9,809	10,972	32,709
Total	19,706	62,417	4,093	12,234	23,799	74,650

High Wind Case

Additional Resource Zones Selected in High Wind Case	MW	GWh
Resources from 20% RPS Reference Case	9,437	34,581
Distributed Biogas	249	1,855
Distributed Geothermal	175	1,344
San Bernardino - Lucerne	1,800	5,020
Palm Springs	806	2,711
Distributed Wind	468	1,289
Out-of-State Late	1,934	5,295
Fairmont	1,650	5,003
Baja	1,500	4,966
San Diego South	903	2,583
Round Mountain	500	2,759
Distributed Biomass	162	1,138
Pisgah	1,800	4,589
Barstow	450	1,163
Riverside East Incremental	150	354
Total	**21,984**	**74,650**

Resource Mix – High Wind Case	In-State		Out-of-State		Total	
	MW	GWh	MW	GWh	MW	GWh
Biogas	279	2,078	-	-	279	2,078
Biomass	634	4,442	87	610	721	5,052
Geothermal	1,655	12,541	58	445	1,713	12,985
Hydro - Small	22	95	15	66	37	161
Solar PV	1,162	2,483	-	-	1,162	2,483
Solar Thermal	3,163	7,715	534	1,304	3,697	9,019
Wind	9,575	28,419	4,802	14,454	14,376	42,873
Total	**16,490**	**57,773**	**5,496**	**16,879**	**21,985**	**74,651**

High Out-of-State Delivered Case

Additional Resource Zones Selected in High Out-of State Delivered Case		
	MW	**GWh**
Resources from 20% RPS Reference Case	9,437	35,051
Distributed Geothermal	175	1,344
Distributed Biogas	249	1,855
Out-of-State Late	1,934	5,295
San Bernardino - Lucerne	1,800	5,043
Reno Area/Dixie Valley	1,500	8,596
Palm Springs	806	2,711
Round Mountain	500	2,759
Wyoming	3,000	10,493
Distributed Biomass	162	1,138
Fairmont	140	402
Riverside East Incremental	150	354
Total	**19,853**	**74,651**

Resource Mix – High Out-of State Delivered Case						
	In-State		Out-of-State		Total	
	MW	GWh	MW	GWh	MW	GWh
Biogas	279	2,078	-	-	279	2,078
Biomass	575	4,030	87	610	662	4,640
Geothermal	1,655	12,541	938	7,142	2,593	19,683
Hydro - Small	22	95	27	131	49	226
Solar PV	969	2,072	-	-	969	2,072
Solar Thermal	2,101	5,153	534	1,304	2,635	6,457
Wind	5,756	17,681	6,910	21,813	12,666	39,494
Total	**11,357**	**43,650**	**8,496**	**31,000**	**19,853**	**74,650**

High Distributed Generation Case

Additional Resource Zones Selected in High Distributed Generation Case		
	MW	**GWh**
Resources from 20% RPS Reference Case	9,437	34,581
Distributed Biogas	249	1,855
Distributed Geothermal	175	1,344
Distributed Wind	468	1,289
Out-of-State Late	1,934	5,295
Distributed Biomass	162	1,138
Remote DG	9,000	19,236
Distributed Solar	5,186	9,558
Riverside East Incremental	150	354
Total	**26,761**	**74,650**

Resource Mix – High Distributed Generation Case						
	In-State		**Out-of-State**		**Total**	
	MW	**GWh**	**MW**	**GWh**	**MW**	**GWh**
Biogas	279	2,078	-	-	279	2,078
Biomass	403	2,825	87	610	490	3,435
Geothermal	1,415	10,859	58	445	1,473	11,303
Hydro - Small	22	95	15	66	37	161
Solar PV	15,068	30,678	-	-	15,068	30,678
Solar Thermal	1,095	2,674	534	1,304	1,629	3,978
Wind	4,484	13,529	3,302	9,488	7,785	23,017
Total	**22,766**	**62,738**	**3,996**	**11,913**	**26,761**	**74,650**