Investigating a Higher Renewables Portfolio Standard in California

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Energy+Environmental Economics

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Study Sponsors

Los Angeles Department of Water and Power (LADWP)

Pacific Gas and Electric Company (PG&E)

Sacramento Municipal Utilities District (SMUD)

San Diego Gas & Electric Company (SDG&E)

Southern California Edison Company (SCE)

Advisory Panel

A four-member independent advisory panel provided input and feedback on the study development and results. The members of the advisory panel include:

Dr. Dan Arvizu – Director and Chief Executive of the National Renewable Energy Laboratory (NREL), Golden, CO

Dr. Severin Borenstein – Director of the University of California Energy Institute and Co-Director of the Energy Institute at Haas School of Business, UC Berkeley

Dr. Susan Tierney – Managing Principal at Analysis Group Inc., Boston, MA

Mr. Stephen Wright – Retired Administrator, Bonneville Power Administration; General Manager, Chelan County Public Utility District

Study Team

Energy and Environmental Economics, Inc. (E3)

ECCO International

DNV KEMA

Disclaimer

The study was conducted by Energy and Environmental Economics, Inc. (E3), with assistance from ECCO International and DNV KEMA. The study was funded by LADWP, PG&E, SMUD, SDG&E, and SCE (the utilities). A review committee consisting of utility and California Independent System Operator (CAISO) personnel provided technical input on methodology, data and assumptions. The utilities, the CAISO and Advisory Panel members reviewed and commented on assumptions, preliminary results, and earlier drafts of this report.

E3 and the consulting team thank the utilities, the CAISO and the Advisory Panel members for their invaluable input throughout the process of conducting this analysis. However, all decisions regarding the analysis were made by E3, ECCO International and DNV KEMA. E3, ECCO International and DNV KEMA are solely responsible for the contents of this report, and for the data, assumptions, methodologies, and results described herein.

Executive Summary

This report presents the results of a study of a 50% renewables portfolio standard (RPS) in California in 2030. The study was funded by the Los Angeles Department of Water and Power (LADWP), Pacific Gas and Electric Company (PG&E), the Sacramento Municipal Utilities District (SMUD), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE), ("the utilities") to examine the operational challenges and potential consequences of meeting a higher RPS. This study was conducted by Energy and Environmental Economics (E3), with assistance from ECCO International. A companion study was conducted by DMV KEMA examining "smart grid" technologies that may become available to help alleviate challenges associated with high penetration of distributed generation. An independent advisory panel of experts from industry, government and academia was commissioned to review the reasonableness of the assumptions and to provide input on the study. The California Independent System Operator (CAISO) also provided input on key study assumptions.

The utilities asked E3 to study the following questions:

1. What are the **operational challenges** of integrating sufficient renewable resources to achieve a 50% RPS in California in 2030?

2. What **potential solutions** are available to facilitate integration of variable renewable resources under a 50% RPS?

3. What are the **costs and greenhouse gas impacts** of achieving a 40% or 50% RPS by 2030 in California?

4. **Would an RPS portfolio with significant quantities of distributed renewable generation be lower-cost** than a portfolio of large-scale generation that requires substantial investments in new transmission capacity?

5. What are some **"least regrets" steps** that should be taken prior to—or in tandem with—adopting a higher RPS?

6. What **remaining key issues must be better understood** to facilitate integration of high penetration of renewable energy?

This report describes the analysis that E3 undertook to answer these questions. E3 studied four scenarios, each of which meets California's incremental RPS[1] needs between 33% and 50% RPS in different ways:

+ **Large Solar Scenario** meets a 50% RPS in 2030 by relying mostly on large, utility-scale solar PV resources, in keeping with current procurement trends.

[1] This study assumes that a 50% RPS is defined in the same way as California's current 33% RPS. The standard requires generation from eligible renewable resources to be equal to or exceed 50% of retail sales. Large hydroelectric resources do not count as eligible renewable resources.

- **Small Solar Scenario** meets a 50% RPS by 2030 by relying mostly on larger, distributed (1 – 20 MW) ground-mounted solar PV systems. This scenario also includes some new larger wind and solar.
- **Rooftop Solar Scenario** meets a 50% RPS by 2030 relying in large part on distributed residential and commercial rooftop solar PV installations, priced at the cost of installing and maintaining the systems. This scenario also includes some new larger wind and solar.[2]
- **Diverse Scenario** meets a 50% RPS in 2030 by relying on a diverse portfolio of large, utility-scale resources, including some solar thermal with energy storage and some out-of-state wind.

In addition, the study analyzes two scenarios that serve as reference points against which to compare the costs and operational challenges of the 50% scenarios:

- **33% RPS Scenario** meets a 33% RPS in 2030, representing an extension of the resource portfolio that is already expected to be operational to meet the state's current 33% RPS in 2020.
- **40% RPS Scenario** meets a 40% RPS in 2030 by relying mostly on large, utility-scale solar PV resources.

The geographic scope of the analysis is a combination of the CAISO, LADWP and the Balancing Area of Northern California (BANC) Balancing Authority Areas. All scenarios assume that significant investments and upgrades to both the

[2] In this scenario, new rooftop PV systems beyond the current net energy metering cap are assumed to count as a renewable generation source towards meeting the state's RPS. System owners are assumed to be compensated at the cost of installing and maintaining the systems (i.e. rooftop PV is priced at cost in the revenue requirement calculation). No incentives for solar are assumed, nor does the analysis consider any transfers that could occur if system owners were compensated through other mechanisms, e.g., through net energy metering.

California electrical grid and the state's fleet of thermal generators occur between 2013 and 2030, including the development of a newer, more flexible fleet of thermal generation. Thus, the results of the 33% RPS Scenario are not necessarily indicative of the challenges of meeting a 33% RPS in 2020. Moreover, if these investments are not realized, the operational challenges and costs of meeting a higher RPS in 2030 might look very different than what is shown here.

Table 1 shows the mix of renewable resources modeled for each of the scenarios described above. In addition to the renewable resources added to meet the RPS target, the study assumes that a total of 7,000 MW of behind-the-meter solar photovoltaic resources are installed by 2030 under California's net energy metering (NEM) policies, enough to meet approximately 5% of total load. These resources are assumed to reduce retail sales, but they do not count toward meeting the 2030 RPS.

Table 1: 2030 Renewable generation by resource type and scenario (in GWh)

	33% RPS	40% RPS	50% RPS Large Solar	50% RPS Diverse	50% RPS Small Solar	50% RPS Rooftop Solar
Utility RPS Procurement						
Biogas	2,133	2,133	2,133	4,422	2,133	2,133
Biomass	7,465	7,465	7,465	9,754	7,465	7,465
Geothermal	16,231	16,231	16,231	20,811	16,231	16,231
Hydro	4,525	4,525	4,525	4,525	4,525	4,525
Solar PV - Rooftop	0	943	2,290	2,290	2,290	22,898
Solar PV - Small	6,536	9,365	13,405	13,405	31,724	11,116
Solar PV - Large	22,190	33,504	49,667	29,059	31,349	31,349
Solar Thermal	4,044	4,044	4,044	10,913	4,044	4,044
Wind (In State)	20,789	24,561	29,948	27,659	29,948	29,948
Wind (Out-of-State)	4,985	4,985	4,985	11,854	4,985	4,985
Subtotal, Utility Gen	**88,897**	**107,755**	**134,693**	**134,693**	**134,693**	**134,693**
Customer Renewable Generation						
Solar PV – Rooftop, net energy metered	10,467	10,467	10,467	10,467	10,467	10,467
Subtotal, Customer Gen	**10,467**	**10,467**	**10,467**	**10,467**	**10,467**	**10,467**
Total Renewable Generation						
Total, All Sources	**99,365**	**118,222**	**145,160**	**145,160**	**145,160**	**145,160**

The study is the first comprehensive effort to assess the technical challenges of operating the California system at a 50% RPS with high penetration of both wind and solar energy. This study examines scenarios for California with up to 15% of electric load served by wind energy, and 28% served by solar energy. This is a much higher penetration of wind and solar energy than has ever been achieved anywhere in the world. In Germany, widely known as a world leader in renewable energy deployment, 21.9% of electricity generation was renewable in

2012, including 7.4% wind and 4.5% solar.[3] In Spain, renewable energy represented 24% of total generation in 2012, including 18% wind and 4% solar.[4] Wind served 30% of domestic load in Denmark in 2012[5]; however, Denmark is a very small system with strong interconnections to the large European grid, and it frequently sells excess wind energy to its neighbors. Other jurisdictions such as Norway, New Zealand and British Columbia have served over 90% of electric load with renewables by counting large hydroelectric resources; these resources do not count toward California's RPS.

At the same time, numerous studies have pointed to the need to decarbonize the electric sector as a key strategy for achieving deep, economy-wide reductions in greenhouse gas emissions as well as energy security and economic development benefits.[6] To that end, many other jurisdictions have set high renewables goals. The European Union Renewables Directive mandates that at least 20% of total energy consumption (including transportation, industrial and other non-electric fuel uses) come from renewable energy sources by 2020. By 2030, Germany plans to generate 50% of its electricity supply with renewable sources, including large hydro.[7] Finland aims to achieve 38% of final energy consumption (including transportation, etc.) from renewable energy sources by

[3] "Gross electricity generation in Germany from 1990 to 2012 by energy source," Accessed July 2013. <www.ag-energiebilanzen.de/componenten/download.php?filedata=1357206124.pdf&filename=BRD_Stromerzeugung1990_2012.pdf&mimetype=application/pdf>

[4] "Statistical series of the Spanish Electricity System," Red Electrica, 2013, Accessed August 2013. <http://www.ree.es/ingles/sistema_electrico/series_estadisticas.asp >

[5] "Monthly Statistics: Electricity Supply," Danish Energy Agency, Accessed: August 2013. < http://www.ens.dk/info/tal-kort/statistik-nogletal/manedsstatistik>

[6] See http://www.ipcc.ch/pdf/assessment-report/ar4/syr/ar4_syr.pdf, http://www.iea.org/techno/etp/etp10/English.pdf, and http://www.ethree.com/publications/index_2010.php.

[7] "Energy Policies of IEA Countries – Germany," International Energy Agency, 2013 http://www.iea.org/w/bookshop/add.aspx?id=448

2020 by relying in large part on biomass resources.[8] While no country has served 40 or 50 percent of its load with variable wind and solar resources, California is not alone in considering potential futures with high renewables. This study represents an important advancement in understanding the impacts of achieving a high RPS.

This report is organized as follows. The remainder of this section summarizes the study's key findings in response to the six questions posed above. Section 2 describes the analytical approach and key inputs to the study. Section 3 describes the analysis of operational challenges associated with a 50% RPS. Section 4 introduces a number of potential solutions that may provide lower-cost ways of integrating renewable resources into the grid. Section 5 presents the cost and greenhouse gas impacts of achieving a 50% RPS. Section 6 concludes by discussing the results and summarizing the research needs identified in this study. A series of technical appendices provide details about the analysis that was conducted.

OPERATIONAL CHALLENGES OF ACHIEVING A 50% RPS

The study utilizes E3's Renewable Energy Flexibility (REFLEX) Model on ECCO's ProMaxLT production simulation platform to investigate the operational and flexibility requirements associated with a 50% RPS. REFLEX is specifically designed to investigate renewable integration issues.[9] REFLEX performs random

[8] "Energy Policies of IEA Countries – Finland," International Energy Agency, 2013, http://www.iea.org/Textbase/npsum/finland2013SUM.pdf

[9] Throughout this report, the term "renewable integration" is used to encompass a range of operational challenges encountered under higher renewable energy penetrations including "overgeneration" of resources,

draws of weather-correlated load, wind, solar and hydro conditions taken from a very large sample of historical and simulated data. REFLEX thus considers operational needs associated with high and low load conditions, high and low hydro conditions, and a range of wind and solar conditions, as well as a broad distribution of the hourly and sub-hourly operating reserve requirements.

REFLEX runs are presented for four scenarios: (1) the 33% RPS Scenario, (2) the 40% RPS Scenario, (3) the 50% RPS Large Solar Scenario, and (4) the 50% RPS Diverse Scenario.[10] Additional runs are presented for variations of the 50% RPS Large Solar Scenario which include the implementation of several potential renewable integration solutions. This analysis does not attempt to find an optimal generation mix or set of renewable integration solutions under the 50% RPS scenarios. Rather, the analysis explores the operational challenges of a 50% RPS and provides directional information about the potential benefits and cost savings of the renewable integration solutions.

The largest integration challenge that emerges from the REFLEX runs is "overgeneration". Overgeneration occurs when "must-run" generation—non-dispatchable renewables, combined-heat-and-power (CHP), nuclear generation, run-of-river hydro and thermal generation that is needed for grid stability—is greater than loads plus exports. This study finds that overgeneration is pervasive at RPS levels above 33%, particularly when the renewable portfolio is

whereby electricity supply exceeds demand net of exports, as well as the fuel costs associated with ramping fossil generation to meet load net of renewable generation.

[10] REFLEX runs were not conducted for the Small Solar and Rooftop Solar Scenarios. The integration challenges for these scenarios are very similar to those of the Large Solar Scenario; therefore the Large Solar Scenario is used as a proxy for all three high solar scenarios.

dominated by solar resources. This occurs even after thermal generation is reduced to the minimum levels necessary to maintain reliable operations.

Figure 1 shows an April day in 2030 under the 33% RPS, 40% RPS, and the 50% RPS Large Solar Scenarios on which the system experiences both low load conditions and high solar output. A very small amount of overgeneration is observed at 33% RPS. The 40% RPS Scenario experiences over 5,000 MW of overgeneration, while the 50% RPS Large Solar Scenario experiences over 20,000 MW of overgeneration.

Table 2 shows overgeneration statistics for the 33%, 40% and 50% RPS Large Solar Scenarios. In the 33% RPS scenario, overgeneration occurs during 1.6% of all hours, amounting to 0.2% of available RPS energy.[11] In the 50% RPS Large Solar case, overgeneration must be mitigated in over 20% of all hours, amounting to 9% of available RPS energy, and reaches 25,000 MW in the highest hour. Potential solutions or portfolios of solutions must therefore be available during large portions of the year and must comprise a large total capacity.

This study assumes that managed curtailment of renewable generation occurs whenever total generation exceeds total demand plus export capability. This is critical to avoid too much energy flowing onto the grid and causing potentially serious reliability issues. As long as renewable resource output can be curtailed in the manner assumed here, the study does not find that high penetration of wind and solar energy results in loss of load. Renewable curtailment is

[11] Curtailment as a percentage of available RPS energy is calculated as: overgeneration divided by the amount of renewable energy that is needed to meet a given RPS target.

therefore treated as the "default" solution to maintain reliable operations. However, the study also evaluates additional solutions that would reduce the quantity of renewable curtailment that is required.

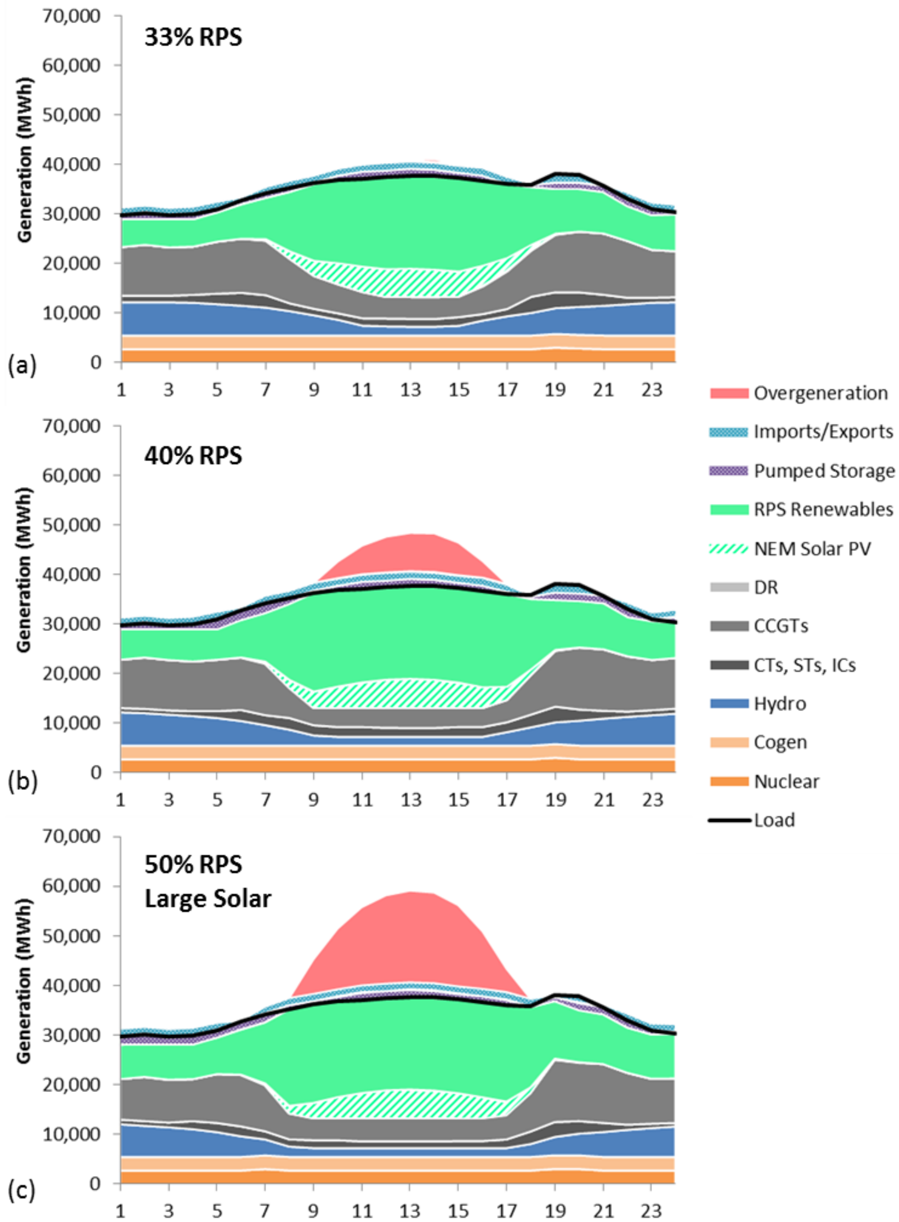


Figure 1: Generation mix calculated for an April day in 2030 with the (a) 33% RPS, (b) 40% RPS, and (c) 50% RPS Large Solar portfolios showing overgeneration

Table 2: 2030 Overgeneration statistics for the 33%, 40% and 50% RPS Large Solar Scenarios

Overgeneration Statistics	33% RPS	40% RPS	50% RPS Large Solar
Total Overgeneration			
GWh/yr.	190	2,000	12,000
% of available RPS energy	0.2%	1.8%	8.9%
Overgeneration frequency			
Hours/yr.	140	750	2,000
Percent of hours	1.6%	8.6%	23%
Extreme Overgeneration Events			
99th Percentile (MW)	610	5,600	15,000
Maximum Observed (MW)	6,300	14,000	25,000

REFLEX also tests for shortages in "ramping" capability – the ability of the generation fleet to accommodate large changes in the net load served over one or more hours.[12] While the scenarios evaluated in this study show no instances of a shortage of ramping capability that would create reliability problems, this result is driven partly by the assumption that renewable curtailment can be utilized not just to avoid overgeneration, but also as a tool to manage net load ramps. In order to ensure reliable operations, REFLEX utilizes "prospective" curtailment, in which the system operator looks ahead one or more hours, subject to uncertainty and forecast error, and curtails renewable output in order to smooth out hourly and multi-hour ramps. This occurs in instances where this system would otherwise be unable to accommodate the steep upward ramps from the mid-afternoon "trough" in net load to the evening peak. Planned and

[12] Net load is defined as load minus renewable generation.

carefully-managed curtailment is therefore a critical tool that is used in the modeling to maintain reliable operations in the face of overgeneration and ramping challenges caused by the higher RPS.

The quantity of managed renewable energy curtailment increases exponentially for RPS requirements that move from 40% to 50% RPS. For example, while the *average* curtailed RPS energy for the 50% RPS Large Solar Scenario is 9%, the *marginal* curtailment—the proportion of the next MWh of renewable resources added to the portfolio that must be curtailed—is significantly higher: 22-25% for most renewable resources and 65% for solar PV, as seen in Table 3. Curtailment amounts to 26% of the RPS energy required to move from a 33% to 50% RPS under the Large Solar Scenario.

Table 3: Marginal overgeneration (% of incremental MWh resulting in overgeneration) by technology for various 2030 RPS scenarios

Technology	33% RPS	40% RPS	50% RPS Large Solar	50% RPS Diverse
Biomass	2%	9%	23%	15%
Geothermal	2%	9%	23%	15%
Hydro	2%	10%	25%	16%
Solar PV	5%	26%	65%	42%
Wind	2%	10%	22%	15%

POTENTIAL INTEGRATION SOLUTIONS

Implementation of one or more renewable integration solutions may reduce the cost of achieving a 50% RPS relative to the default renewable curtailment solution. This study considers the following potential solutions: (1) Enhanced Regional Coordination; (2) Conventional Demand Response; (3) Advanced

Demand Response; (4) Energy Storage; and, (5) 50% RPS with a more diverse renewable resource portfolio (the Diverse Scenario). The most valuable integration solutions are those that can reduce solar-driven overgeneration during daylight hours when the system experiences low load conditions. Downward flexibility solutions, including increased exports, flexible loads, and diurnal energy storage help to mitigate this overgeneration. Alternatively, procurement of a more diverse portfolio of renewable resources, which includes less solar and disperses the renewable generation over more hours of the day, reduces the daytime overgeneration compared to the Large Solar portfolio.

The study evaluates changes in the renewable integration challenges associated with the 50% RPS Large Solar Scenario from sequentially implementing potential integration solutions sized at 5,000 MW. The study therefore evaluates the directional impact of the solution, but does not attempt to identify an optimal or least-cost set of solutions. Table 4 shows the overgeneration statistics for the Large Solar Scenario and each of the solutions tested. With only the renewable curtailment solution implemented, overgeneration is approximately equal to 9% of the available renewable energy. Integration solutions that provide only upward flexibility, like conventional demand response, do not significantly decrease this overgeneration. However, integration solutions that provide 5,000 MW of downward flexibility, such as energy storage, reduce the overgeneration to between 3% and 4% of the available renewable energy.

Similarly, the diverse portfolio of renewable resources evaluated here reduces overgeneration to approximately 4% of the available renewable energy.[13]

This study assesses each of the solutions in isolation, with the aim of indicating promising directions for further investigation. However, preliminary analysis suggests that the effects of the various solutions, if implemented together, are complementary. Because overgeneration increases exponentially at RPS levels approaching 50%, optimization of the renewable portfolio with a combination of solutions could substantially reduce the quantity of curtailment required to meet a 50% RPS. However, avoiding all instances of renewable curtailment may be cost-prohibitive.

[13] This study considers a diverse portfolio consisting of specific quantities of in-state wind, out-of-state wind, solar thermal with energy storage, and other technologies. A different renewable generation mix would result in a different quantity of overgeneration.

Table 4: 2030 overgeneration statistics for 50% RPS Large Solar Scenario and four solution cases

Overgeneration Statistics	50% RPS Large Solar	Enhanced Regional Coordination	Conventional Demand Response	Advanced DR or Energy Storage	Diverse Portfolio
Total Overgeneration					
GWh/yr.	12,000	4,700	12,000	5,000	5,400
% of available RPS energy	8.9%	3.4%	8.8%	3.7%	4.0%
Overgeneration					
Hours/yr.	2,000	1,000	2,000	1,200	1,300
Percent of hours	23%	12%	23%	14%	15%
Extreme Overgeneration Events					
99th Percentile (MW)	15,000	9,900	15,000	9,900	10,000
Maximum Observed (MW)	25,000	20,000	25,000	20,000	19,000

The solution quantities evaluated in these cases are informed by the size of the overgeneration caused by a 50% RPS, and not by any estimate of the feasibility or technical potential to achieve each solution. For example, we are not aware of any detailed studies of the technical potential for pumped storage or upwardly-flexible loads in California. Battery technologies have not been fully demonstrated as commercial systems in the types of applications or at the scale required to address the integration issues identified in this study. Regional coordination is promising but has progressed slowly over the past decade. There are likely to be significant challenges to implementing any of these solutions.

COST AND RATE IMPACTS

This study calculates the statewide total cost and average retail rate for each of the 50% RPS scenarios. The 33% and 40% RPS scenarios are shown as a reference point. The total cost includes the cost of procuring and operating the renewable and thermal resources considered in this study, the cost of transmission and distribution system investments needed to deliver the renewable energy to loads, and non-study-related costs such as the cost of the existing grid. The costs do not include real-time grid operating requirements such as maintaining frequency response. The total cost for the study area is divided by projected retail sales to calculate an average, ¢/kWh rate across all customer classes.

As a backdrop, the study estimates that the average retail rate in California could increase from 14.4 ¢/kWh in 2012 to 21.1 ¢/kWh in 2030 (in 2012 dollars), a 47% increase, before higher levels of RPS beyond the current 33% statute are taken into consideration.[14] This increase is driven largely by trends outside the scope of this study, such as the need to replace aging infrastructure, rather than by RPS policies. Other analysis has estimated that compliance with the current 33% RPS is expected to raise investor owned utility rates by 6-8% between 2011 and 2030; the approximately 40% remaining rate impact expected over this period would be attributable to other factors.[15]

[14] Throughout the study, all costs are presented in 2012 real dollars unless otherwise noted.

[15] This estimate is derived from analysis developed by E3 in the Long-Term Procurement Plan (LTPP) proceeding http://www.cpuc.ca.gov/NR/rdonlyres/070BF372-82B0-4E2B-90B6-0B7BF85D20E6/0/JointIOULTPP_TrackI_JointIOUTestimony.pdf

Achieving a 40% RPS could lead to an additional increase of 0.7 ¢/kWh, or 3.2%, over the 33% RPS Scenario under base case assumptions regarding the price of natural gas, CO_2 emissions allowances and renewable energy resources. A 50% RPS would increase rates by 9 – 23% relative to a 33% RPS under base case assumptions.

Figure 2, Table 5 and Table 6 below show the average rate increase of each of the five RPS scenarios compared to the 33% portfolio in 2030. The analysis reveals several interesting findings:

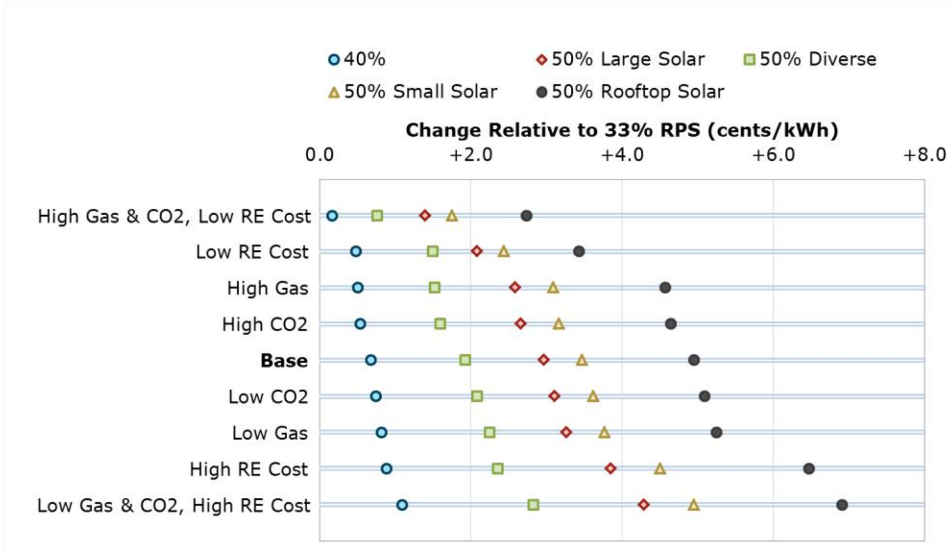
1. Under a wide range of CO_2, natural gas and renewable energy prices (gas prices from $3-10/MMBtu, CO_2 prices from $10-100/metric ton, and a range of solar PV and wind costs) the higher RPS Scenarios result in an increase in average electric rates. The rate impacts are expected to be lowest under the high gas & CO_2 price sensitivity with low renewable energy costs.

2. Rate increases are expected to be significantly higher under the 50% RPS Scenarios than under the 40% RPS Scenario. This is primarily due to the exponential increase in renewable curtailment as the RPS target increases towards 50%, requiring a significant “overbuild” of the renewable portfolio to meet the RPS target.

3. The Diverse Scenario shows a substantially lower rate impact than the more heavily solar dominated cases, primarily because the diverse portfolio results in less overgeneration.

4. The rank order on costs between the Scenarios stays the same under all uncertainty ranges considered. Costs are expected to be highest under the

Rooftop Solar Scenario, followed by the Small Solar, Large Solar and Diverse Scenarios. The cost differences between these sensitivity results are reduced when assuming lower solar PV costs than in the base case.



Note: RE = renewable energy

Figure 2: Cost differences between RPS portfolios under a range of assumptions; relative to 2030 33% RPS scenario (2012 cents/kWh)

Table 5: Average electric rates for each Scenario under a range of input assumptions (2012 cents/kWh)

	33% RPS	40% RPS	50% RPS Large Solar	50% RPS Diverse	50% RPS Small Solar	50% RPS Rooftop Solar
Average System Rate (2012 cents/kWh)						
Base	21.1	21.8	24.1	23.1	24.6	26.1
Low Gas	19.8	20.6	23.0	22.0	23.5	25.0
High Gas	22.9	23.4	25.5	24.4	26.0	27.5
Low CO_2	20.5	21.2	23.6	22.5	24.1	25.6
High CO_2	22.6	23.1	25.2	24.2	25.7	27.2
Low RE Cost	21.0	21.5	23.1	22.5	23.5	24.5
High RE Cost	21.2	22.1	25.1	23.6	25.7	27.7
Low Gas & CO_2, High RE Cost	19.2	20.3	23.5	22.0	24.1	26.1
High Gas & CO_2, Low RE Cost	24.2	24.4	25.6	25.0	26.0	27.0

Table 6. Percent change in average electric rates of each Scenario relative to 33% RPS Scenario, under a range of input assumptions (% change in 2012 $)

	33% RPS	40% RPS	50% RPS Large Solar	50% RPS Diverse	50% RPS Small Solar	50% RPS Rooftop Solar
Percentage Change in Average System Rate (relative to 33% RPS)						
Base	n/a	3.2%	14.0%	9.1%	16.4%	23.4%
Low Gas	n/a	4.1%	16.5%	11.3%	19.1%	26.5%
High Gas	n/a	2.2%	11.3%	6.6%	13.5%	19.9%
Low CO_2	n/a	3.6%	15.2%	10.2%	17.7%	24.9%
High CO_2	n/a	2.4%	11.8%	7.1%	14.0%	20.6%
Low RE Cost	n/a	2.3%	9.9%	7.1%	11.6%	16.3%
High RE Cost	n/a	4.2%	18.1%	11.1%	21.2%	30.5%
Low Gas & CO_2, High RE Cost	n/a	5.7%	22.3%	14.7%	25.8%	36.0%
High Gas & CO_2, Low RE Cost	n/a	0.7%	5.8%	3.1%	7.2%	11.3%

The projected cost increases for the higher RPS scenarios are due largely to the high and increasing cost of renewable integration. While wind and solar costs are projected to be comparable to the cost of conventional resources on a levelized cost of energy (LCOE) basis in 2030, overgeneration and other integration challenges have a substantial impact of the total costs for the 50% RPS scenarios. Moreover, renewable generation is shown to have very little resource adequacy benefits beyond 33% RPS due to increased saturation of the grid with solar energy (see section 2.3).

Table 7: 2030 revenue requirement (2012 $ billion) for each Scenario, percentage change is relative to 33% RPS

Revenue Requirement Category	33% RPS	40% RPS	50% RPS Large Solar	50% RPS Diverse	50% RPS Small Solar	50% RPS Rooftop Solar
CO_2 Compliance Cost	3.2	2.9	2.5	2.4	2.5	2.5
Conventional Generation	20.3	19.5	18.7	18.1	18.7	18.6
Renewable Generation	8.2	10.6	17.1	14.8	18.5	22.8
Transmission	6.5	7.1	7.8	7.9	7.4	7.3
Distribution	16.2	16.2	16.3	16.3	16.7	16.5
Misc/Other Costs	2.5	2.5	2.5	2.5	2.5	2.5
Total	**56.9**	**58.8**	**64.9**	**62.1**	**66.3**	**70.3**
Percentage Change	n/a	3.2%	14.0%	9.1%	16.4%	23.4%

The total cost of each scenario, in terms of annual revenue requirement in 2030, is shown in Table 7, while the cumulative capital investment through 2030, incremental to meeting a 33% RPS in 2020, for each scenario is shown in Table 8.

Table 8: Cumulative capital investment through 2030, incremental to 33% RPS in 2020, by scenario (2012 $ billion)

	33% RPS	40% RPS	50% RPS Large Solar	50% RPS Diverse	50% RPS Small solar	50% RPS Rooftop Solar
New Renewable Generation	9.2	29.5	65.2	61.0	72.0	105.3
New Conventional Generation	11.7	11.2	11.2	11.2	11.2	11.2
New Transmission	2.8	6.6	12.0	15.2	9.3	8.5
New Distribution	0.6	0.9	1.4	1.4	4.2	3.0
Total Capital Investment	**24.4**	**48.1**	**89.8**	**88.7**	**96.6**	**128.0**

The total increase in annual revenue requirement associated with a 50% RPS in 2030 ranges from $5.2 to $13.3 billion above the 33% RPS scenario; this includes CO_2, fuel and capacity savings in the conventional generation cost category, as well as increases in renewable procurement costs. The cumulative capital investment in the 50% RPS Scenario ranges from $64.4 to $103.7 billion above the 33% RPS scenario, in real 2012 dollars under base case assumptions, before the implementation of the additional renewable integration solutions that are investigated in this study.

EFFECT OF RENEWABLE INTEGRATION SOLUTIONS

The cost impacts shown in the tables above incorporate only the "default" integration solution of renewable energy curtailment. Implementation of one or more alternative solutions may reduce the cost impacts by enabling a larger proportion of renewable energy output to be delivered to the grid.

A detailed cost-benefit analysis of these renewable integration solutions is beyond the scope of this study. In lieu of such an analysis, we provide cost and rate results under an illustrative range of high and low cost assumptions for the implementation of 5,000 MW of each of the solutions that are shown to have a potential renewable integration benefit. Even though the study assumes significant quantities of each solution (5,000 MW) are implemented, these cases are not sufficient to fully eliminate the overgeneration challenge.

As noted above, the study does not include an analysis of the optimal level of integration solutions, nor does it assess the feasibility of procuring or implementing 5,000 MW of these renewable integration solutions by 2030. The technical potential to achieve various solutions is unknown, and there are likely to be significant technical, regulatory and permitting barriers to implementing solutions at this magnitude.

Table 9 shows the cost ranges assumed for each solution. These assumptions represent, at a high level, a range of potential costs for each category. In reality, each category would likely be made up of a number of individual measures or projects, each of which would have unique costs and benefits. For example, the energy storage solution case could include a mixture of pumped storage and other storage technologies such as compressed air energy storage (CAES) or flow batteries. Nevertheless, this section provides an indication of the extent to which cost reductions might be achieved through implementation of solutions in each of these categories.

Table 9: High and low cost estimates for solution categories modeled in this study (2012 $)

Solution	Sensitivity	Basis	Cost Metric
Storage	Low	Pumped hydro cost ($2,230/kW; 30-yr lifetime); Black and Veatch *Cost and Performance Data for Power Generation Technologies*[16]	$375/kW-yr
	High	Battery cost ($4,300/kW; 15-yr lifetime); Black and Veatch *Cost and Performance Data for Power Generation Technologies*	$787/kW-yr
Flexible Load	Low	Load shift achieved through rate design at no incremental cost	$0/kW-yr
	High	Average TRC cost of thermal energy storage ($2,225/kW; 15-yr lifetime); E3 *Statewide Joint IOU Study of Permanent Load Shifting*[17]	$413/kW-yr
Regional Coordination	Low	Assume CA receives $50/MWh for exported power	-$50/MWh exported
	High	Assume CA pays $50/MWh to export incremental power	$50/MWh exported

Figure 3 shows the effect of implementing these solutions, compared to the 33% RPS Scenario. As a benchmark, the 50% RPS Large Solar Scenario, with only the default renewable curtailment solution, is expected to increase average

[16] Study available at: http://bv.com/docs/reports-studies/nrel-cost-report.pdf.
[17] Study available at: http://www.ethree.com/public_projects/sce1.php.

rates by 3 ¢/kWh, or 14%, relative to the 33% RPS Scenario. The Diverse Scenario is also shown as an integration solution, along with a point estimate of its rate impact under base case assumptions. The Diverse Scenario reduces the average rate by 1 ¢/kWh relative to the Large Solar Scenario.

The Enhanced Regional Coordination and Advanced DR solutions provide cost savings relative to the Large Solar Scenario, even under the "high" cost range. The "low" cost range for energy storage, modeled here as 5,000 MW of relatively low-cost pumped storage, would be expected to reduce the total cost of achieving the 50% RPS Large Solar Scenario by just over 0.5 ¢/kWh.[18] Only the high-cost battery storage case results in higher costs; however, it should be noted that the engineering cost estimates shown here do not include site-specific costs, performance guarantees and other costs that would be incurred during commercial deployment. All of the solution cases modeled here result in higher expected rates compared to the 33% RPS Scenario.

[18] This study does not assess the feasibility of implementing 5,000 MW of pumped storage in the state by 2030.

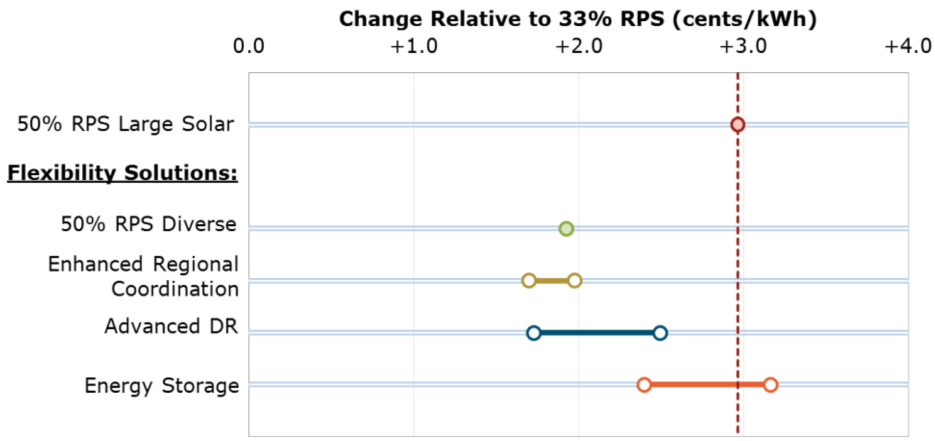


Figure 3: Cost impacts of solution cases (assuming 5,000 MW change) under low and high cost ranges, relative to 2030 33% RPS Scenario (2012 cents/kWh)

GREENHOUSE GAS IMPACTS

The 50% RPS Scenarios reduce greenhouse gas (GHG) emissions relative to the 33% RPS Scenario. Increasing the RPS from 33% to 40% reduces GHG emissions by approximately 6 million metric tons in 2030, while a 50% RPS would reduce GHG emissions by 14-15 million metric tons relative to a 33% RPS in 2030. The implied cost of GHG emissions reductions is calculated as the change in total cost (excluding CO_2 compliance costs) divided by the change in GHG emissions relative to the 33% RPS Scenario.[19] The implied carbon abatement cost is \$340/ton for the 40% RPS Scenario, \$403/ton for Diverse Scenario, and \$637/ton for the Large Solar Scenario, under the default renewable curtailment

[19] This formulation implicitly attributes all of the cost of meeting a higher RPS to GHG emissions reductions. It therefore ignores other potential societal benefits of increased renewable penetration such as reduced emissions of "criteria" pollutants such as NO_x and SO_x.

solution. GHG abatement costs would be reduced if lower-cost, low carbon solutions to the overgeneration challenge can be implemented.

DISTRIBUTED GENERATION IMPACTS

This study considers two scenarios composed largely of distributed solar PV generation (DG PV): a Small Solar and a Rooftop Solar Scenario. DG PV is assessed for its impact on the distribution and transmission systems as well as for the difference in cost and performance relative to larger systems located in sunnier areas. The study relies on the methods used in previous studies for the California Public Utilities Commission (CPUC) to determine both benefits—in the form of reduced system losses and deferred transmission and distribution investments—and costs—in the form of distribution system upgrades needed to accommodate high levels of DG that result in “backflow” from distribution feeders onto the main grid.

The Small Solar and Rooftop Scenarios are found to be costlier than the Large Solar and Diverse Scenarios. This is largely due to the difference in cost and performance assumed for DG PV systems relative to central station systems. Rooftop systems, in particular, are significantly more expensive to install on a per-kW basis than larger systems and have lower capacity factors. Rooftop PV systems tend to have lower capacity factors (partly due to suboptimal tilt and orientation) relative to larger, ground-mounted systems that can utilize tracking technologies. DG PV is found to reduce transmission costs relative to larger systems located in remote areas; however, distribution costs are found to be higher due to the need for significant investments to accommodate very high penetration of PV on the distribution system. It should be noted that this study does not address issues related to retail rate design or net energy metering. The DG PV systems are priced at the cost of installing and maintaining the systems, identical to the treatment of central station PV systems, in the revenue requirement and average rate calculations.

NEXT STEPS

Although the focus of this study is on grid operations with very high renewable penetrations in 2030, there are a number of shorter-term "least-regrets" opportunities that the evidence in this report suggests should be implemented prior to or in parallel with a higher RPS standard. The four "least regrets" opportunities identified in this study include:

1. **Increase regional coordination.** This study shows that increased coordination between California and its neighbors can facilitate the task of integrating more renewable resources into the bulk power system at a lower cost. Although California already depends on its neighbors for imports during summer peak periods, an increased level of coordination across the West would include more sharing of flexible resources to support better integration of the rich endowment of wind energy in the Pacific Northwest and Rocky Mountains and solar resources in the Desert Southwest.
2. **Pursue a diverse portfolio of renewable resources.** The study shows that increasing the diversity of resources in California's renewable energy portfolio has the potential to reduce the need for managed curtailment. More diverse renewable generation profiles can better fit within California's energy demand profile. The benefits of developing a diverse portfolio are complemented by and in many ways tied directly to increased regional coordination, since the largest benefit is likely to be achieved through increased geographic diversity across a wide area.

3. **Implement a long-term, sustainable solution to address overgeneration before the issue becomes more challenging.** A long-term, sustainable implementation and cost-allocation strategy to manage the potential large amounts of overgeneration that could result from a higher RPS should be developed before overgeneration jeopardizes reliability, and before curtailment impacts financing of new renewable generation projects. A long-term, sustainable solution must be technically feasible, economically efficient and implementable in California. It must include a mechanism for ensuring that renewable developers continue to receive a sufficient return to induce investment in projects on behalf of California ratepayers.

4. **Implement distributed generation solutions.** Increased penetration of distributed generation necessitates a more sustainable, cost-based strategy to procure distributed generation. This requires a reexamination of retail rate design and net energy metering policies, as well as implementation of distribution-level solutions and upgrades, including smart inverters with low-voltage ride-through capabilities that allow distributed photovoltaic systems to operate under grid faults.

There are also a number of key areas for future research that are beyond the scope of this study, but are critical to enable the bulk power systems to continue to work reliably and efficiently in the future. These include:

+ **The impact of a combined strategy of multiple renewable integration solutions.** This study finds that grid integration solutions will be critical to achieving a higher RPS at lowest cost. Because each solution has its own specific costs and benefits, a critical next step is to analyze combinations of these potential solutions to help develop a more comprehensive, longer-term grid integration solution to higher RPS.

+ **Research and development for technologies to address overgeneration.** Technology needs to support higher renewable energy penetration and to address the overgeneration challenge include diurnal energy flexibility and efficient uses for surplus solar generation during the middle of the day. Promising technologies include:
    - Solar thermal with energy storage;
    - Pumped storage;
    - Other forms of energy storage including battery storage;
    - Electric vehicle charging;
    - Thermal energy storage; and
    - Flexible loads that can increase energy demand during daylight hours.
+ **Technical potential and implementation of solutions.** This study points to the need for solutions to the renewable integration challenges to be planned and implemented on the same timeline as, or before, higher renewable penetration. However, the technical potential to achieve each solution is unknown at this time. A significant effort is needed to characterize the technical potential, cost, and implementation challenges for pumped storage, battery technologies, upwardly-flexible loads, more diverse renewable resource portfolios, and other potential renewable integration solutions.
+ **Sub-five minute operations.** A better understanding of the sub-five minute operations, including frequency, inertia and regulation needs, under a higher RPS is needed. This is particularly pressing in California where significant changes are planned to the state's existing thermal generation fleet, including the retirement of coastal generators utilizing once-through cooling. Research is needed regarding potential costs and the feasibility and performance of potential solutions, such as synthetic inertia.

- **Size of potential export markets for excess energy from California.** California has historically been an importer of significant quantities of electric energy. Under a 50% RPS, California would have excess energy to sell during many hours of the year. The extent to which electricity providers in other regions might be willing to purchase excess energy from California is unknown. This study assumes that California can export up to 1500 MW of energy during every hour of the year based on a high-level assessment of supply and demand conditions in other regions, and shows that higher levels of exports could significantly reduce the cost of achieving a 50% RPS. Further research might be able to shed additional light on this question.
- **Transmission constraints.** This study does not include an assessment of transmission constraints within California, and how those constraints might impact renewable integration results including reliability, cost and overgeneration. For example, if a large proportion of the solar energy resources modeled in this study are located in Southern California, northbound transmission constraints on Path 15 and Path 26 may result in significantly higher overgeneration than is indicated in this study. Challenges may also be more acute within the BANC and LADWP Balancing Authority Areas, which have limited transfer capability to the CAISO system.
- **Changing profile of daily energy demand.** Daily load shapes are expected to evolve over time, with increases in residential air conditioning and electric vehicle loads. This could shift the peak demand period farther into the evening, potentially exacerbating the overgeneration challenge during daylight hours.[20]

[20] San Diego Gas & Electric and Sacramento Municipal Utility District are already seeing peak demand occur between 5:30 and 6:00 pm on some days.

+ **Future business model for thermal generation and market design.** This analysis points toward a fundamental shift in how energy markets are likely to operate under high penetration of renewable energy. Energy markets are unlikely to generate sufficient revenues to maintain the flexible fleet of gas generation that the state will need to integrate high levels of renewable energy. Moreover, there may be a significant number of hours in which market prices are negative. New market products for flexibility, inertia, frequent startups and capacity may be necessary to ensure that the generation fleet maintains the necessary operating characteristics.

+ **Optimal thermal generation fleet under high RPS.** Procurement choices will need to be made regarding trade-offs between combined-cycle gas generators, frame and aeroderivative combustion turbines, and other technologies with newly-important characteristics for renewable integration, such as low minimum generation levels and high ramp rates. The flexibility needs of the state's thermal fleet may also interact with local air quality regulations, which limit the number of permitted power plant starts.

+ **Natural gas system impacts and supply.** Operating the grid under a higher RPS may require more flexibility in the natural gas delivery system and markets. Whether the natural gas delivery system can support the simultaneous operation of gas-fired generators necessary for renewable integration is an important area for further research.

+ **Operational challenges of a 40% RPS.** The study finds that overgeneration occurs at 33% RPS and is significant at 40% RPS, but does not evaluate the impact of renewable integration solutions at a 40% RPS in detail.

+ **Cost-effectiveness of a higher RPS relative to other measures for reducing GHG emissions.** This study indicates that a 50% RPS may be a relatively high-cost means of reducing GHG emissions (over $300/ton, as compared to CO_2 allowance price forecasts of \$30-100/ton). To be sure, there are many other benefits from higher renewable penetration besides GHG reduction. Nevertheless, it would be instructive to compare the cost of a 50% RPS with the cost of reducing GHG emissions in other sectors such as transportation, industry and buildings.

CONCLUSION

This study assesses the operational impacts, challenges, costs, greenhouse gas reductions, and potential solutions associated with a 50% RPS in California by 2030. The study finds that renewable integration challenges, particularly overgeneration during daylight hours, are likely to be significant at 50% RPS. The study indicates that at high penetrations of renewable generation, some level of renewable resource curtailment is likely to be necessary to avoid overgeneration and to manage net load ramps. The study also identifies a number of promising integration solutions that could help to mitigate overgeneration, including procurement of a diverse portfolio of renewable resources, increased regional coordination, flexible loads, and energy storage. Achievement of a higher RPS at least cost to electric customer will likely require implementation of a portfolio of integration solutions; timely implementation of these solutions is critical but would likely involve substantial challenges related to cost, feasibility, and siting. In this study, a 50% RPS is shown to lead to higher electric rates than a 33% RPS under a wide range of natural gas prices, CO_2 allowance prices, and renewable resource costs. The lowest-cost 50% RPS portfolio modeled here is one with a diversity of renewable resource technologies. The highest-cost portfolio modeled is one that relies extensively on rooftop solar photovoltaic systems. This study highlights the need for additional research in a number of areas, including the need to address sub-five-minute operational issues, ensure sufficient power system flexibility, and develop strategies to avoid overgeneration.

1 Introduction

1.1 Motivation for Study

California has among the most aggressive clean energy policies in the world. In 2002 the California Legislature enacted one of the country's first renewable portfolio standards, which required the investor-owned utilities to obtain 20% of delivered energy supply from designated renewable resources, excluding large hydropower. California subsequently raised the goal to 33% by 2020. Thousands of megawatts of new renewable capacity will enter commercial operation over the next several years, driven by the federal stimulus program and state policies. The California Solar Initiative will result in the installation of 3,000 MW of distributed solar generation by 2016, and feed-in tariff programs are driving additional development of distributed generation. Meanwhile, policies are still being developed to realize Governor Brown's goal to develop 12,000 MW of distributed generation. These new resources augment California's already low-carbon generation mix composed of hydropower, nuclear and efficient natural gas generation.

With California well on its way to achieving a 33% RPS, policy-makers, market participants and other stakeholders are turning their attention to additional measures that might reduce carbon emissions. Governor Brown suggested in his 2013 State of the State address that by 2020 the penetration of renewable energy in California would probably exceed the 33% target. Others have suggested raising the target for renewable penetration to 40% or even 51% by 2030.[21] As it updates its AB32 Scoping Plan, the California Air Resources Board (CARB) is looking out to 2030 and examining potential pathways to reduce GHG emissions below the 2020 target. Recent studies taking a longer term view have found that California must almost completely decarbonize electricity generation to meet its goal of reducing greenhouse gas emissions to 80% below 1990 levels by 2050.[22]

With greening the grid comes the challenge of integrating ever greater amounts of intermittent generation. Wind and solar power are now the fastest growing components of the utilities' renewable portfolios. According to CPUC projections, solar power will account for nearly half of California's renewable energy production by 2020.[23] Accommodating this solar surge presents challenges for both the bulk power system and the distribution grid. At the system level, California will need strategies to manage unprecedented amounts of renewable generation during the middle of the day, when solar production may exceed local demand. California's balancing authorities must devise strategies to manage the steep upward and downward ramps that occur as solar power comes on line in the mornings and then falls off in the late afternoon. On distribution circuits, higher PV penetration may lead to voltage fluctuation, islanding, partial feeder overloads and backward power flows. Smart grid

[21] On January 24, 2013 Assemblyman Manuel Perez introduced Assembly Bill 177, which would have required an increase in the RPS goal to 51% by 2030. While AB177 did not make it out of committee, it signals emerging interest in pursuing further increases in renewable penetration in California.

[22] Williams, James H. et al, "The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050: The Pivotal Role of Electricity," *Science*, **335** (53) 2012.

[23] CPUC Renewables Portfolio Standard Quarterly Report, 3rd and 4th Quarters 2012, **http://www.cpuc.ca.gov/NR/rdonlyres/4F902F57-78BA-4A5F-BDFA-C9CAF48A2500/0/2012_Q3_Q4RPSReportFINAL.pdf**

solutions at the distribution level will be needed. Wind and solar are both variable and uncertain, and the potential for a sudden loss of large quantities of renewable production, e.g., as a weather front moves through an area, requires dispatchable generators that operate at less than maximum generation in order to provide upward operating reserves. This variability in generation due to weather can be reduced through geographic and renewable technology diversity.

The challenge of integrating intermittent renewables may be partially alleviated by other expected changes in California's thermal generation fleet. The retirement and partial replacement of once-through cooling power plants along the coast has created an opportunity for the development of more flexible thermal generation and other replacement power options. The same is true for the replacement of California's imported coal resources, which are expected to be entirely replaced before 2030. At the same time, coastal generators currently provide critical inertia that is needed for system stability, and reliable operations will likely continue to require operation of thermal generation in coastal load centers to maintain voltage and to meet local reliability needs.

This study provides an initial investigation into the requirements, operational challenges, potential solutions and costs of integrating higher levels of renewable energy penetration onto California's electrical grid in 2030.

1.2 Renewable Energy Penetrations in Other Countries and Other Studies of High RPS

Renewable penetrations in the United States and around the world are increasing. A 50% RPS in California requires a much higher level of wind and solar penetration than has ever been achieved anywhere in the world. In Germany, widely known as a world leader in renewable energy deployment, 21.9% of electricity generation was renewable in 2012, including 7.4% wind and 4.5% solar.[24] In Spain, renewable energy represented 24% of total generation in 2012, including 18% wind and 4% solar.[25] Wind served 30% of domestic load in Denmark in 2012[26]; however, Denmark is a very small system with strong interconnections to the large European grid, and it frequently sells excess wind energy to its neighbors. Other jurisdictions such as Norway, New Zealand and British Columbia have served over 90% of electric load with renewables by counting large hydroelectric resources; these resources do not count toward California's RPS.

While practical, operational experience with high variable renewable energy levels is limited, the integration challenges associated with renewable penetrations exceeding 20 to 30% have been the subject of several recent studies. In 2010, the California ISO published a detailed analysis of the

[24] "Gross electricity generation in Germany from 1990 to 2012 by energy source," Accessed July 2013. <www.ag-energiebilanzen.de/componenten/download.php?filedata=1357206124.pdf&filename=BRD_Stromerzeugung1990_2012.pdf&mimetype=application/pdf>

[25] "Statistical series of the Spanish Electricity System," Red Electrica, 2013, Accessed August 2013. <http://www.ree.es/ingles/sistema_electrico/series_estadisticas.asp >

[26] "Monthly Statistics: Electricity Supply," Danish Energy Agency, Accessed: August 2013. < http://www.ens.dk/info/tal-kort/statistik-nogletal/manedsstatistik>

operational challenges in achieving a 20% RPS.[27] The analysis found that a 20% RPS impacted system operations, but that the generation fleet was largely flexible enough to accommodate increases in ramping, load following, and regulation reserves. Self-scheduling (i.e. generator dispatch decisions made by the power plant owner rather than the system operator) was identified as a potential barrier to utilizing the full flexibility of the thermal fleet.

A similar operational analysis of the state of Hawaii under increasing renewable penetrations in 2013 was commissioned by the National Renewable Energy Laboratory (NREL).[28] The Hawaii Solar Integration Study, which focused on reserve requirements and frequency response, found that some challenges of renewable integration could be mitigated with renewables themselves by installing governor controls to enable dynamic renewable curtailment. The study also found that reaching 25% renewable penetration on the small island systems would require approximately 20% of the available renewable energy to be curtailed.

One common thread throughout the literature is that achieving higher renewable penetrations is easier with larger, more interconnected systems. In 2010, the GE Western Wind and Solar Integration Study found that a 35% renewable penetration in the WestConnect region was feasible if new operational strategies were pursued, including improved BA cooperation, day-

[27] GE Energy Consulting and California ISO, "Integration of Renewable Resources: Operational Requirements and Generation Fleet Capability at 20% RPS", 2010. <**http://www.caiso.com/2804/2804d036401f0.pdf**>
[28] NREL, "Hawaii Solar Integration Study," Technical Report, NREL/TP-5500-57215, June 2013. <**http://www.nrel.gov/docs/fy13osti/57215.pdf**>

ahead forecasting, and sub-hourly scheduling.[29] The Renewable Electricity Futures Study, published by NREL in 2012, provided an analysis of grid integration challenges for meeting 80% of the electricity demand in the contiguous United States with renewable resources, nearly 50% of which may be variable and uncertain.[30] NREL's analysis identified the following requirements for achieving an 80% renewable penetration: improved system flexibility from generation units, energy storage, or demand response; renewable resource diversity, enabled by expansion of transmission infrastructure; and mechanisms to ensure adequate planning and operating reserves for system reliability. One particularly important assumption in the Renewable Electricity Futures Study was that institutional (i.e. non-transmission) constraints between balancing areas were ignored in order to take full advantage of geographical diversity.

1.3 Description of the Flexibility Challenge

Wind and solar energy resources are both variable and uncertain. They are variable in the sense that their energy production changes from minute to minute, and from hour to hour, depending on wind speed and insolation. This variability requires the system operator to carry operating reserves – dispatchable resources that can vary their output with wind and solar production to ensure that electricity supply is exactly equal to demand at each

[29] GE Energy, "Western Wind and Solar Integration Study," Subcontractor Report, NREL/SR-550-47434, May 2012. <http://www.nrel.gov/docs/fy10osti/47434.pdf>
[30] NREL, "Renewable Electricity Futures Study," NREL/TP-6A20-52409, 2012. <http://www.nrel.gov/docs/fy13osti/52409-ES.pdf>

moment. Wind and solar resources are also uncertain, because the level of energy production cannot be predicted with perfect accuracy. The system operator must also carry additional operating reserves to account for forecast error – the possibility that actual production from the wind and solar resources is significantly higher or lower than expected.

Variability and uncertainty are not new problems for grid operations – electric load is also variable and uncertain, and the output of thermal generators is not perfectly predictable due to unplanned outages, changes in atmospheric temperature and pressure and other factors. System operators have historically accommodated variability by committing and operating "regulating" reserves – resources that vary their output automatically based on the needs of the grid, either through direct detection of the grid frequency conditions or via automated signal from the control center. The CAISO procures Regulation Up and Regulation Down products through its Day-Ahead and Hour-Ahead market processes; SMUD and LADWP provide these products on their systems by committing their own resources.

What is different under high renewable penetration is the scale of the challenge. Renewable penetrations of 40% or 50% that include large shares of wind and solar power lead to variability and forecast error that far exceed historical operating experience. Modeling conducted by the CAISO has indicated that, under some circumstances, the system may not have enough flexible capacity to meet the ramping requirements—the requirement to change output rapidly in the upward or downward direction—imposed by load, wind and solar. Moreover, modeling of higher RPS levels conducted for this study indicates that California will frequently experience overgeneration conditions, i.e. hours when "must-run" generation (generation which nominally cannot be dispatched downward, including wind, solar, combined-heat-and-power generation, and thermal generation needed for local reliability) is greater than load.

Figure 4 below shows a sample operating day in January that illustrates four distinct types of flexibility challenges that the system will face under high renewable penetration. The dark black line near the top indicates the load that must be served during each hour. The shaded bands indicate the types of resources that are operating throughout the day.

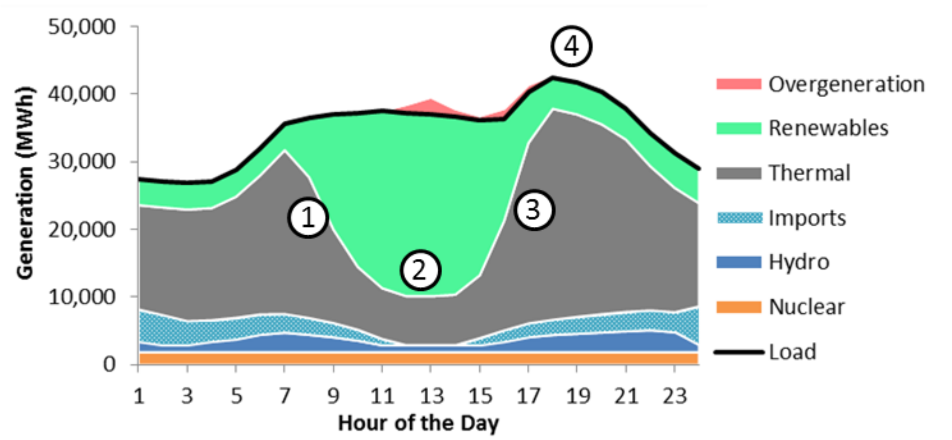


Figure 4: High penetration of variable resources presents four related planning challenges (sample operating day in January, 2030)

Four flexibility challenges are numbered in Figure 4:

1. **Downward ramping capability:** Thermal resources operating to serve loads at night must be ramped downward and potentially

shut down to make room for a significant influx of solar energy after the sun rises, in this case around 8:00 AM.

2. **Minimum generation flexibility:** Overgeneration may occur during hours with high renewable production even if thermal resources and imports are reduced to their minimum levels. A system with more flexibility to reduce thermal generation will incur less overgeneration.

3. **Upward ramping capability:** Thermal resources must ramp up quickly from minimum levels during the daytime hours and new units may be required to start up to meet a high net peak demand that occurs shortly after sundown.

4. **Peaking capability:** The system will continue to need enough resources to meet the highest peak loads with sufficient reliability.

A fifth flexibility challenge, not visible on the chart, involves ensuring that sufficient resources are operating to provide necessary real-time services such as primary frequency response, regulation, and inertia. This challenge can be exacerbated by variable renewable resources, which tend to require more balancing resources and may not be able to provide these services as effectively as thermal generation. These challenges may be significant at 50% RPS, but are beyond the scope of this study.

1.4 About this Study

The analysis was completed over approximately four months starting in April 2013. The data inputs draw as much as possible from existing datasets and publicly available forecasts that are in use at the CEC, CPUC and CAISO. The study benefited from technical input and involvement from the state's five largest electric utilities: LADWP, PG&E, SMUD, SCE and SDG&E as well as the CAISO. A four-member independent Advisory Panel also provided feedback and input on the scenario development and analysis, but is in no way responsible for the report's results or conclusions. The Advisory Panel members come from a diverse background in academia, public power, public service, and the private sector.

This study employs new modeling techniques to evaluate the unique operational challenges of integrating high levels of renewable penetration onto the electrical grid. The analysis accounts for the variable and intermittent nature of electrical loads, hydroelectric availability and renewable generation through stochastic simulation with economic dispatch, using E3's Renewable Energy Flexibility (REFLEX) model. The REFLEX model was run by ECCO International on its ProMaxLT modeling platform.

This study provides a first-of-its kind snapshot of how California's electrical grid might operate under a high RPS policy in 2030 under a variety of scenarios and cost assumptions. The study does not evaluate the potential for regulation or inertia needs under a high renewable penetration future. Furthermore, it should be noted that this is *not* an implementation study of whether it would be feasible to achieve a 40 or 50% RPS by 2030. The analysis does not consider permitting and construction timelines or market dynamics that may affect implementation of a higher RPS in California. Likewise, this study does not evaluate a higher RPS within the context of other carbon-reduction strategies and policies in the electricity sector or other sectors of the economy. This study does not endorse any particular policy or strategy for renewable procurement.

The study provides technical information about the potential value of alternative strategies for reducing renewable integration challenges, but many questions remain about the circumstances under which flexibility measures would be needed and the cost and benefits of alternative potential solutions, particularly since technology and energy markets will continue to evolve over the next 17 years.

This study's investigation into renewable integration needs is accompanied by a companion analysis by DNV KEMA, "Qualitative Investigation of Distribution System Technical Issues and Solutions: Ranking of Distribution Smart Grid Options." In it, DNV KEMA provides a qualitative assessment of the potential for new technologies to help enable and integrate high levels of distributed renewable generation onto the distribution grid (See Appendix F).

2 Approach and Assumptions

2.1 Overview of Modeling Approach

This report analyzes the operational challenges and cost of achieving a 50% RPS in 2030 in a Study Area comprising most of California (CAISO, LADWP and BANC Balancing Authorities). The report assesses changes to the composition and operations of California's fleet of generating resources that are necessary to accommodate load growth and increased renewable penetration between 2013 and 2030. The costs of transmission system and distribution system investments are estimated, but the study does not identify individual facilities that might be needed in 2030. The study presents estimates of total 2030 revenue requirements and average retail rates in ¢/kWh. Six scenarios are considered, four in which a 50% RPS is achieved, a 40% RPS scenario, and a 33% RPS scenario.

Several quantitative models are employed:

- E3's **Renewable Energy Capacity Planning Model (RECAP)** is used to ensure that each resource portfolio achieves a 1-day-in-10 year reliability standard. The results of this analysis are described in Section 2.3 and Appendix A.
- Operations of California's fleet of resources are simulated using E3's **REFLEX Model**, deployed on ECCO International's **ProMaxLT** platform.

REFLEX samples daily profiles of load, wind, solar and hydro conditions from a multi-year database of actual and modeled values. ProMaxLT's optimal unit commitment and economic dispatch software is then utilized to simulate operations at daily, hourly and five-minute timesteps. Reliability violations such as unserved energy, overgeneration and ramping deficiencies are tracked, and solutions are assessed for their ability to reduce these violations. The results of this analysis are described in Section 3 and Appendix B.

+ E3's **Renewable Distributed Generation (RDG) Potential Model** estimates the cost of distribution system investments required to deliver the quantities of RDG specified in each scenario. The results of this analysis are described in Section 2.4 and Appendix C. Appendix E describes the ProMaxLT modeling platform.
+ E3's **Renewable Energy Costing Tool**, developed for the Western Electric Coordinating Council, is used to estimate new resource capital cost and performance characteristics and to calculate cost-based PPA prices for new renewable resources.
+ E3's spreadsheet model calculates the total 2030 revenue requirement for the Study Area, including the fixed costs of the base 2030 system along with the costs of renewables, new thermal capacity, fuel costs, CO_2 allowance costs, and the cost of renewable integration. Transmission cost upgrades associated with meeting higher levels of RPS are approximated using a \$/kW-yr rule of thumb for in-state and out-of-state resources. The results of this analysis are described in Section 5 with additional details on the revenue requirement provided in Appendix D.

The following chart shows the flow of data and assumptions through the various models that are employed for this study.

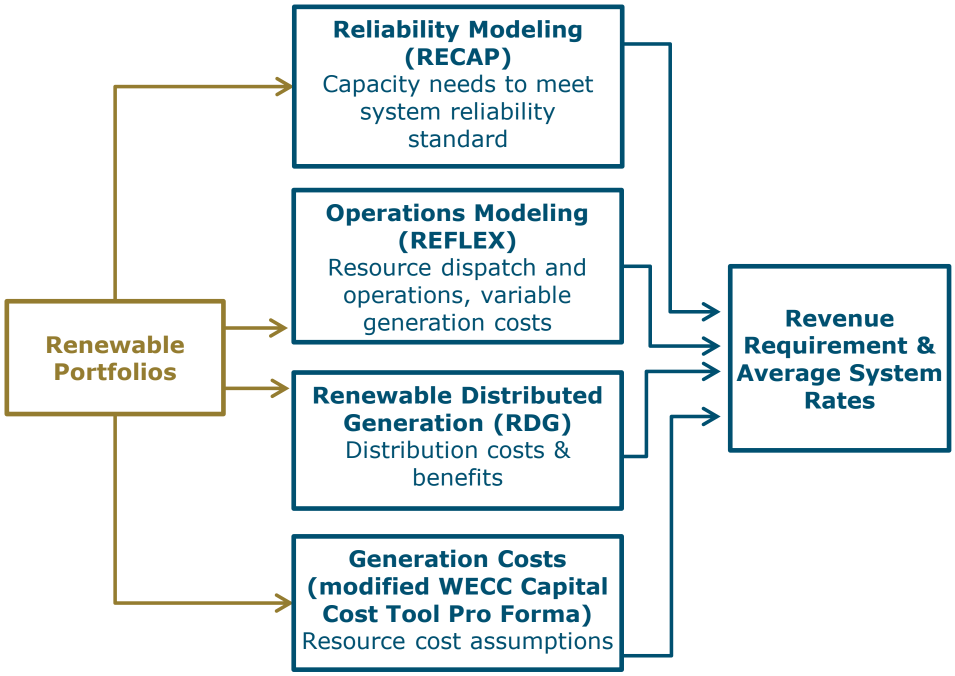


Figure 5: Illustration of the analytical framework utilized to study a 50% RPS

2.2 Scenarios

This study analyzes four alternative scenarios for achieving a 50% RPS by 2030:

+ **Large Solar Scenario** meets a 50% RPS in 2030 by relying mostly on large, utility-scale solar resources, in keeping with current procurement trends. The incremental renewable resources that are required to move from a 33% RPS to a 50% RPS are primarily ground-mounted central station solar PV in areas of the state with high insolation. The scenario also includes some small solar and large wind projects.

+ **Small Solar Scenario** meets a 50% RPS by 2030 by relying mostly on larger distributed (1 - 20 MW) ground-mounted solar PV systems. The portfolio consists of a mix of distributed solar PV systems, with some located near load pockets and some located in remote areas with higher insolation. The scenario also includes some new larger solar and wind projects.

+ **Rooftop Solar Scenario** meets a 50% RPS by 2030 relying in large part on distributed residential and commercial rooftop solar PV installations. This scenario also includes some new larger wind and solar. Rooftop PV systems beyond the current net energy metering cap are assumed to count as a renewable generation source towards meeting the state's RPS. System owners are assumed to be compensated at the cost of installing and maintaining the systems (i.e. rooftop PV is priced at cost in the revenue requirement calculation. No incentives for solar are assumed, nor does the analysis consider any transfers that could occur if system owners were compensated through other mechanisms, e.g., through net energy metering.
+ **Diverse Scenario** meets a 50% RPS in 2030 by relying on a diverse portfolio of large, utility-scale resources. In this scenario, the utilities are assumed to procure resources with the express goal of creating a diverse portfolio that minimizes flexibility issues. The portfolio comprises a mix of small and large scale solar PV, solar thermal with storage, in-state wind, out-of-state wind, geothermal, biomass and biogas resources.

In addition to these 50% scenarios, the study also analyzes two additional scenarios that serve as reference points:

+ **33% RPS Scenario** represents an extension of the resource portfolio that is already expected to be operational to meet the state's current 33% RPS in 2020. The 2020 portfolio was provided to E3 by the utilities; E3 assumed that any additional procurement required to meet a 33% RPS by 2030 would consist mostly of large-scale solar PV. The resources in the

33% RPS portfolio are assumed to be common to all of the other scenarios.

+ **40% RPS Scenario** meets a 40% RPS in 2030 by relying mostly on large, utility-scale solar resources. The incremental renewable resources that are required to move from a 33% RPS to a 40% RPS are primarily ground-mounted central station solar PV in areas of the state with high insolation, consistent with current procurement patterns. Some large wind projects are included as well.

The following charts show the composition of the renewable resource portfolios for each scenario. The assumed definition of renewable resources for RPS compliance in 2030 is the same as used today (i.e. large hydroelectric resources are excluded), with the exception of some new rooftop solar PV which is treated as a renewable generation resource rather than a load modifier.

Table 10: 2030 renewable generation by resource type and scenario (in GWh)

	33% RPS	40% RPS	50% RPS Large Solar	50% RPS Diverse	50% RPS Small Solar	50% RPS Rooftop Solar
Utility RPS Procurement						
Biogas	2,133	2,133	2,133	4,422	2,133	2,133
Biomass	7,465	7,465	7,465	9,754	7,465	7,465
Geothermal	16,231	16,231	16,231	20,811	16,231	16,231
Hydro	4,525	4,525	4,525	4,525	4,525	4,525
Solar PV - Rooftop	0	943	2,290	2,290	2,290	22,898
Solar PV - Small	6,536	9,365	13,405	13,405	31,724	11,116
Solar PV - Large	22,190	33,504	49,667	29,059	31,349	31,349
Solar Thermal	4,044	4,044	4,044	10,913	4,044	4,044
Wind (In State)	20,789	24,561	29,948	27,659	29,948	29,948
Wind (Out-of-State)	4,985	4,985	4,985	11,854	4,985	4,985
Subtotal, Utility Gen	**88,897**	**107,755**	**134,693**	**134,693**	**134,693**	**134,693**
Customer Renewable Generation						
Solar PV – Rooftop, net energy metered	10,467	10,467	10,467	10,467	10,467	10,467
Subtotal, Customer Gen	**10,467**	**10,467**	**10,467**	**10,467**	**10,467**	**10,467**
Total Renewable Generation						
Total, All Sources	**99,365**	**118,222**	**145,160**	**145,160**	**145,160**	**145,160**

Table 11: 2030 renewable capacity by resource type and scenario (in MW)

	33% RPS	40% RPS	50% RPS Large Solar	50% RPS Diverse	50% RPS Small Solar	50% RPS Rooftop Solar
Utility RPS Procurement						
Biogas	397	397	397	724	397	397
Biomass	1,243	1,243	1,243	1,550	1,243	1,243
Geothermal	1,950	1,950	1,950	2,531	1,950	1,950
Hydro	1,282	1,282	1,282	1,282	1,282	1,282
Solar PV - Rooftop	0	629	1,529	1,529	1,529	15,286
Solar PV - Small	3,039	4,192	5,839	5,839	13,308	4,906
Solar PV - Large	9,437	13,672	19,722	12,008	12,865	12,865
Solar Thermal	1,555	1,555	1,555	3,516	1,555	1,555
Wind (In State)	7,613	8,918	10,781	9,989	10,781	10,781
Wind (Out-of-State)	1,847	1,847	1,847	3,966	1,847	1,847
Subtotal, Utility Gen	**28,363**	**35,685**	**46,145**	**42,935**	**46,757**	**52,113**
Customer Renewable Generation						
Solar PV – Rooftop, net energy metered	7,000	7,000	7,000	7,000	7,000	7,000
Subtotal, Customer Gen	**7,000**	**7,000**	**7,000**	**7,000**	**7,000**	**7,000**
Total Renewable Generation						
Total, All Sources	**35,363**	**42,685**	**53,145**	**49,935**	**53,757**	**59,113**

2.3 Capacity Needs Assessment

In order to ensure that the REFLEX modeling is focused solely on resource flexibility, and does not show loss of load events related to insufficient capacity, E3 first tests each of the scenarios to ensure that the fleet of renewable and conventional resources meets a reliability standard of no more than one loss-of-load event in 10 years. This is done using E3's Renewable Energy Capacity Planning (RECAP) Model developed for the CAISO. RECAP uses standard industry techniques to calculate loss-of-load frequency (LOLF), loss-of-load expectation (LOLE), loss-of-load duration (LOLD), and expected unserved energy (EUE). RECAP also calculates the effective load carrying capability (ELCC) of a resource as the quantity of additional load it can serve while continuing to meet the reliability standard.

Table 12 shows the over-capacity (negative) or under-capacity (positive) in each of the RPS scenarios to meet the 1-in-10 standard. Starting thermal generation assumptions were provided by the utilities. The analysis indicates that 615 MW of new capacity is needed in the 33% RPS Scenario; the annualized cost of 615 MW of new frame combustion turbines is therefore added to the revenue requirement. The 40% and 50% RPS scenarios show capacity surpluses in 2030 due to the much higher level of renewable capacity; this benefit is captured in the revenue requirement as reduced resource adequacy (RA) requirements for these scenarios.

Table 12: Resource need/surplus to meet 1-day-in-10-year reliability standard in 2030 (MW)

Scenario	Resource need/(surplus) (MW)
33% RPS	615
40% RPS	-150
50% RPS Large solar	-762
50% RPS Diverse	-2764

Table 13 shows the resource additions and their RA contribution for achieving a 33% RPS and additional increments beyond. To achieve a 33% RPS, 28,544 MW of renewables are installed, resulting in 11,292 MW of ELCC that contributes to

RA. Moving from 33% to 40% requires 8,332 MW of additional renewable capacity; however, these resources provide only 765 MW of RA benefit. The ELCC of this increment of resources is only 9% of nameplate capacity due to saturation of the grid with solar PV resources. Moving from 40% to the 50% RPS Large Solar Scenario requires 11,904 MW of additional resources, however, these resources add only 612 MW of RA benefit, for an average ELCC of 5%. For the Diverse Scenario, 8194 MW of resources are added, providing 2,614 MW of RA benefit.

Table 13: Incremental renewable resource additions and effective load carrying capability for 40% RPS and 50% RPS scenarios

	RPS Installed Nameplate Added (MW)	Incremental Resource Adequacy Contribution (MW)	ELCC of Incremental wind and solar PV
From 0% to 33% RPS	28,544	11,292	40%
From 33% to 40% RPS	8,332	765	9%
From 40% to 50% RPS Large Solar	11,904	612	5%
From 40% to 50% RPS Diverse	8,194	2,614	32%

2.4 Transmission and Distribution Costs

This study includes a high-level assessment of the potential transmission and distribution system costs and benefits of a higher RPS future in California based on the limited distribution system upgrade cost data that is currently available in California.

2.4.1 TRANSMISSION COSTS

A simple 'rule-of-thumb' approach is used to estimate the incremental transmission costs associated with achieving higher levels of renewable generation in California for each 2030 scenario. This approach is appropriate because the renewable resources assumed for each 2030 scenario are not associated with specific geographical areas. Rather, transmission costs are classified only as being associated with "in-state" or "out-of-state" renewable generation.

- **In-state transmission:** The in-state transmission cost adder is calculated using transmission cost and renewable build-out data from the 2010 Long-Term Procurement Plan (LTPP). The in-state transmission cost adder is calculated by dividing the 2020 CAISO revenue requirement for transmission driven by renewable need ($911 million in 2012$) by the incremental renewable resources procured in the CAISO area through 2020, excluding any out-of-state and distributed resources (26,922 GWh). This results in an in-state transmission cost assumption of $34 per MWh in 2012 dollars.
- **Out-of-state transmission:** The out-of-state transmission cost adder is applied only in the 50% RPS Diverse Scenario to out-of-state renewable resources. The out-of-state transmission cost is calculated by assuming that 3,000 MW of incremental import capability can be added at an investment cost of $5 billion. This results in an assumed cost of $242/kW-yr, or $46 per MWh assuming a line utilization rate of 60%.

2.4.2 DISTRIBUTION COSTS

The study relies on the methods used in previous studies for the California Public Utilities Commission (CPUC) to determine both benefits, in the form of reduced system losses and deferred transmission and distribution investments, and costs, in the form of distribution system upgrades needed to accommodate high levels of DG that result in "backflow" from distribution feeders onto the main grid.

2.4.2.1 DG Build-Out Assumptions

Three variations on a future distributed generation build-out are modeled as part of the Scenarios:

+ **Rooftop Solar Scenario:** Assumes very high penetration of rooftop PV systems (up to 33% of households). While rooftop PV systems initially yield benefits due to avoided or reduced investment in distribution system infrastructure, oversaturation of distribution feeders leads to significant distribution system upgrade costs and backflow into the bulk power system.
+ **Small Solar Scenario:** Assumes new policies to target and direct development of distributed generation are used to help minimize total system costs, including resource costs as well as transmission and distribution costs. This scenario meets the incremental RPS need from 33 to 50% renewables primarily with commercial rooftop and ground-mounted systems with better cost and performance characteristics than the small rooftop systems.
+ **All Other Scenarios:** The 33%, 40%, 50% RPS Large Solar and 50% RPS Diverse scenarios all assume 7,000 MW of rooftop PV is installed under

current Net Energy Metering polices. Lower concentration of DG resources for these scenarios leads to lower distribution system upgrade costs.

Table 14 shows the share of installed capacity by installation type for the two DG scenarios. It includes all non-RPS compliant net energy metered (NEM) resources in IOU territory, equal to the estimated NEM cap of 7,000 MW, in addition to those required for RPS.

Table 14: Share of installed capacity by category, and percentage of CA households with PV, for Small Solar and Rooftop Scenarios

Scenario	Installed capacity by percentage of total	
	50% RPS Rooftop Solar	50% RPS Small Solar
Residential Roofs below saturation point	40.1%	24.3%
Residential Roofs above saturation point	38.1%	9.3%
Commercial Roofs	6.0%	17.0%
Ground	15.9%	49.4%
Percentage of CA households with PV	32.9%	13.8%

2.4.2.2 Distribution System Upgrade Costs

Distribution system costs from DG installations are estimated using a simple methodology that is illustrated in the following chart. It is assumed that DG can be interconnected at a low cost up until a saturation point is reached, at which point interconnection costs increase substantially. The cost of interconnection is represented by a simple $/kW value derived from utility interconnection studies. The high interconnection portion of the chart is represented by the mean of utility interconnection study cost results for larger ground and commercial systems – a value of $300/kW. Interconnection costs before the saturation point are assumed to be one tenth of this cost, or $30/kW.

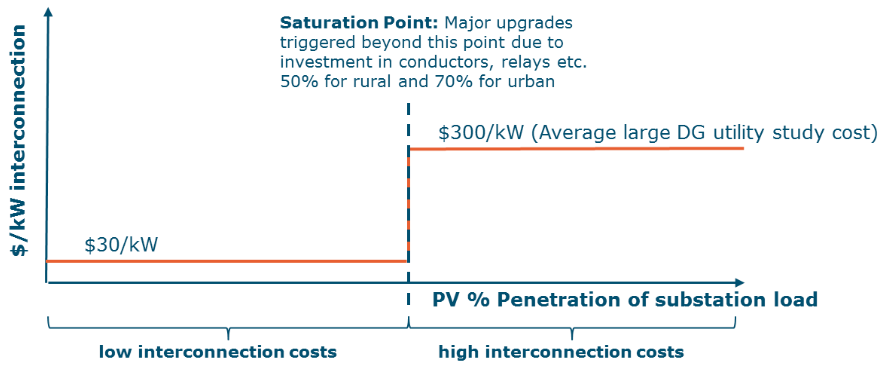


Figure 6: Conceptual methodology for estimating distribution system costs on a given distribution system substation

2.4.2.3 Distribution System Benefits

Distributed PV may also help to defer transmission and distribution system investments, and reduce system losses. Reduced system losses are captured in through reduced generation requirements. Reductions in transmission costs are captured in the resource costing analysis, in which fewer new transmission upgrades are required. Calculation of investment deferral benefits on the distribution and sub-transmission system is accomplished using an adapted version of the methodology in the 2012 CPUC LDPV Report.[31] In the CPUC

[31] See Appendix C. http://www.cpuc.ca.gov/NR/rdonlyres/8A822C08-A56C-4674-A5D2-099E48B41160/0/LDPVPotentialReportMarch2012.pdf

methodology, distribution avoided costs are calculated from the IOU capital expansion plans.

The distribution benefits realized by each DG project in the analysis are subject to two factors: the coincidence of PV generation with the highest load hours at a substation level, and the maximum benefit realizable by PV, as measured by the difference between load peaks during the solar producing day and during the night. Reduction in the net peak load served at the substation is only possible when the net peak load occurs during daylight hours when PV installations are producing energy. If the maximum annual peak occurs outside of PV production hours, no peak reduction benefit is realized since the distribution system upgrades are driven by the net peak load. Even on daytime-peaking substations, the benefit of PV is limited because high PV penetration eventually pushes the net peak load hour into the nighttime hours. Figure 7 below shows the maximum peak reduction for an example substation with a daytime peak. Only daytime peaking substations can benefit from load reduction from PV. Figure 8 shows the inability of PV to reduce peak load on nighttime peaking substations. These substations receive no benefits from PV in our analysis and represent 34% of all substations in the study.

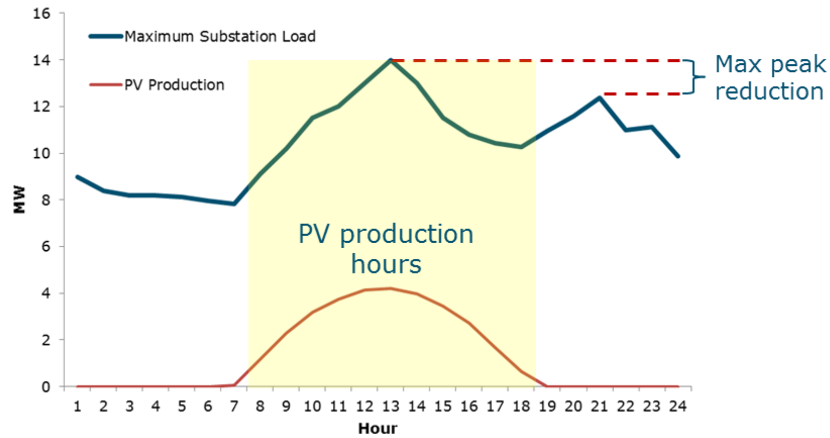


Figure 7: Maximum peak reduction possible with daytime substation peak

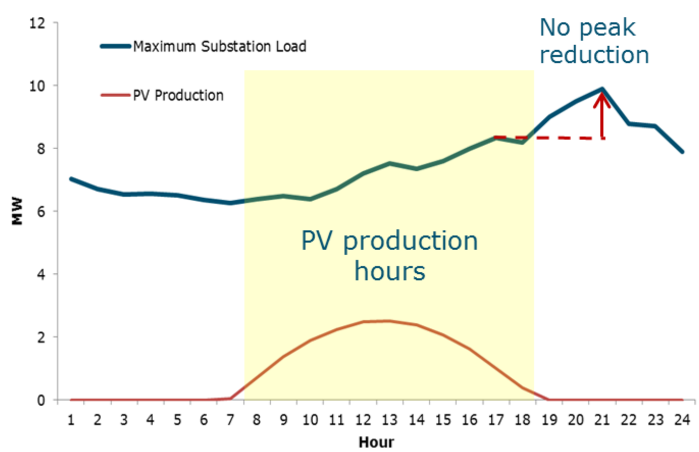


Figure 8: No peak reduction possible with nighttime substation peak

2.4.3 TRANSMISSION AND DISTRIBUTION COST RESULTS

Table 15 below shows the total transmission and distribution system upgrade costs under each of the scenarios. Total transmission and distribution costs are lowest under the 33% RPS Scenario, which includes only the 7,000 MW of NEM systems. Total annual DG-related distribution system costs for this scenario are

$90 million: $257 million in incremental upgrades minus $167 in deferral of growth-related investments. Some additional DG systems are added for the 50% RPS Large Solar and Diverse Scenarios; these systems result in a cumulative total of $203 million in increased annual distribution system costs. The 50% Rooftop Solar Scenario results in $439 million of increased annual distribution system costs; while transmission and distribution avoided costs are higher for this scenario, substantial distribution system upgrades are required. The Small Solar Scenario results in $606 million in increased annual distribution system costs.

Table 15: 2030 distribution and transmission cost impacts of each scenario (annual revenue requirement, 2012 $ millions)

Scenario	Distribution and Sub-Transmission Avoided Costs ($M/yr)*	Distribution Interconnection and Upgrades ($M/yr)*	RPS Transmission Costs (incremental to 33% RPS by 2020, $M/yr)	Total ($M/yr)
33% RPS	(167)	257	406	496
40% RPS	(189)	321	955	1086
50% RPS Large Solar	(210)	413	1740	1942
50% RPS Diverse	(210)	413	1836	2038
50% RPS Small Solar	(234)	840	1345	1951
50% RPS Rooftop PV	(258)	697	1237	1677

*Includes behind the meter net-energy metered projects

2.5 Generation Costs

2.5.1 RENEWABLE RESOURCE COSTS

Renewable resource cost assumptions used in this study reflect the assumption that improvements will occur over time in emerging renewable technologies resulting in reduced capital costs and improved performance, and that current tax credits and incentives for renewable technologies are maintained until their current statutory expiration dates. These assumptions are each described in more detail below.

In each scenario, E3 calculates the direct procurement costs of the additional renewable resources needed to meet each scenario's renewable net short (the "Scenario-specific Procurement Costs" revenue requirement category). Across all scenarios, E3 assumes that these resources are procured through a power purchase agreement (PPA) between a utility and a third-party developer, who would sell the generation from the project to a utility under a long-term contract. E3 calculates the PPA prices used in this analysis from assumptions of resource capital and operating costs and resource capacity factors while accounting for the cost of project finance and the tax benefits associated with renewable development.

This study assumes that the incremental investment in renewable generation needed to meet each scenario's 2030 goal would be evenly spread between 2016 and 2030. The cost of renewables during this future period is uncertain and may change dramatically from today. In order to develop meaningful cost estimates, a two-step process is used to estimate future resource costs. First, 2013 input assumptions are developed—capital cost, operating cost, capacity factor, cost of capital, tax benefits—that, when translated to a PPA price, reasonably approximate prices in today's market. Second, plausible assumptions are applied regarding how these key input assumptions may change through 2030, using these changes to calculate how PPA prices could change over the period of the analysis.

This section describes the methods and assumptions used to derive the cost-based PPAs over the time horizon considered in this analysis. Section 2.5.1.1 presents input assumptions used to derive PPA prices for resources installed in 2013. Section 2.5.1.2 presents the factors that E3 expects to have a material impact on PPA prices over time, as well as this study's assumptions for each of these factors. Section 2.5.1.3 describes the development of the assumptions for the renewable resource sensitivities. Section 2.5.1.4 summarizes the resulting PPA prices for different resources in each of the scenarios.

2.5.1.1 Renewable PPA Prices for Resources Installed in 2013

Table 16 shows the cost and performance assumptions for present-day renewable technologies. Most of these assumptions are based on E3's *Cost and Performance Review of Generation* Technologies, a study completed in 2012 to provide resource cost and performance assumptions for the Western Electric Coordinating Council's (WECC) 10- and 20-year transmission planning studies.[32] One exception is solar PV costs, which are lower than in the WECC report due to the continued cost reductions experienced for that technology.

[32] http://www.wecc.biz/committees/BOD/TEPPC/TAS/121012/Lists/Minutes/1/121005_GenCapCostReport_finaldraft.pdf

Table 16: Cost and performance of renewable technologies installed in 2013 (all costs in 2012 $, capital, fixed O&M costs and capacity factors for solar PV are reported relative to the plant's DC nameplate capacity)

Technology	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Heat Rate (Btu/kWh)	Capacity Factor (%)
Biogas	$ 3,040	$ 131	$ -	10,000	80%
Biomass	$ 4,974	$ 150	$ 4	14,465	85%
Geothermal	$ 6,080	$ 171	$ 5		90%
Hydro - Small	$ 4,238	$ 11	$ -		35%
Solar PV - Residential Rooftop	$ 4,165	$ 37	$ -		14%
Solar PV - Commercial Rooftop	$ 3,123	$ 37	$ -		14%
Solar PV - Fixed Tilt <20MW	$ 2,643	$ 26	$ -		20%
Solar PV - Fixed Tilt >20MW	$ 2,357	$ 23	$ -		20%
Solar PV - Tracking <20MW	$ 3,000	$ 31	$ -		25%
Solar PV - Tracking >20MW	$ 2,692	$ 27	$ -		25%
Solar Thermal - No Storage	$ 5,370	$ 40	$ -		28%
Solar Thermal - Six Hour Storage	$ 7,780	$ 40	$ -		37%
Wind - In-State	$ 2,111	$ 44	$ -		33%
Wind - Out-of-State	$ 1,963	$ 44	$ -		38%

In order to translate these cost and performance inputs into long-term PPA prices, E3 uses a simple pro forma model to calculate cost-based PPA prices at which the developer's cash flow will be sufficient to cover operating costs and debt service while providing the developer with a sufficient return of and on the up-front equity investment. Table 17 summarizes the key financing and tax inputs assumed for resources installed in 2013.

Table 17. Financing and tax assumptions for resources installed in 2013

Technology	Financing Lifetime *(yrs)*	WACC *(%)*	Production Tax Credit *($/MWh)*	Investment Tax Credit *(%)*	MACRS Term *(yrs)*
Biomass	20	7.10%	11		10 + bonus
Biogas	20	7.10%	23		10 + bonus
Geothermal	20	7.10%	23		5 + bonus
Hydro	20	7.10%	11		20 + bonus
Solar PV	25	7.25%		30%	5 + bonus
Solar Thermal	20	7.10%		30%	5 + bonus
Wind	20	7.10%	23		5 + bonus

The resulting cost-based PPAs representative of renewable plants installed in 2013 are summarized in Table 18. The values in this table represent the $/MWh cost at which a developer would sell power to a utility over the lifetime of a long-term contract with no escalation over the contract term. These results were benchmarked against public reported costs for recent renewable contracts, including the aggregated results of IOU RPS solicitations as reported in the CPUC's *Padilla Report to the* Legislature.[33]

[33] See *The Padilla Report to the Legislature: The Costs of Renewables in Compliance with Senate Bill 836* (2013). Available at: http://www.cpuc.ca.gov/NR/rdonlyres/F0F6E15A-6A04-41C3-ACBA-8C13726FB5CB/0/PadillaReport2012Final.pdf

Table 18: Cost-based PPA prices calculated by E3 for resources installed in 2013

Technology	2013 *($/MWh)*
Biogas	$ 85
Biomass	90
Geothermal	107
Hydro - Small	157
Solar PV - Residential Rooftop	223
Solar PV - Commercial Rooftop	177
Solar PV - Fixed Tilt <20MW	103
Solar PV - Fixed Tilt >20MW	91
Solar PV - Tracking <20MW	92
Solar PV - Tracking >20MW	82
Solar Thermal - No Storage	164
Solar Thermal - Six Hour Storage	160
Wind - In-State	69
Wind - Out-of-State	54

2.5.1.2 Future Changes to Resource Prices

While the costs presented above are appropriate to use for resources installed in the present day, long-term studies must consider how the costs of renewable generation will evolve over time. Over time, innovation and technological improvement is expected to drive cost reductions in emerging renewable technologies. To determine appropriate prices to use for resources installed in the future, this study identifies a number of factors that will contribute to the changing costs of renewable procurement over time.

One of the most important considerations is whether and to what extent the capital costs of emerging renewable technologies will decline over time with technological maturation. The downward trend in a technology's cost as it matures is often expressed through a "learning curve," which describes a commonly observed empirical relationship between the cumulative experience of producing a good and the cost to produce it. The functional form of the learning curve is exponential: the "learning rate" represents the reduction in production cost for a good with each doubling of cumulative experience. This relationship is commonly applied to electric generation technologies—most notably to solar PV modules, which have shown persistence to a learning rate of approximately 20%—in order to project the cost of emerging technologies in the future.

This study relies upon the projected technology cost declines described in E3's *Cost and Generation Performance Review*, which were developed though both application of learning curves and a literature review of technically achievable cost reductions. E3 developed plausible trajectories of resource costs for a period twenty years into the future that were intended to reflect a continuation of trends in innovation observed historically. The assumptions underlying each trajectory vary by technology:

+ For **solar PV**, E3 uses a traditional learning curve methodology to estimate plausible future cost reductions. We assume a learning rate of 20% for module costs and 10% for balance-of-systems costs, resulting in a combined 15% learning rate assumption that is applied to all solar PV capital costs. Cost reductions were calculated based on a forecast of global installations developed by the International Energy Agency. The resulting learning curve shows a **29% reduction** in solar PV capital costs between 2013 and 2030.

+ For **solar thermal**, E3 uses a literature review of engineering projections for solar thermal power plant costs to determine an appropriate trajectory. Because learning rates are empirically derived and do not have any physical underpinning, it is difficult to apply learning curves to nascent technologies. E3's choice of a unique methodology for solar thermal ties the trajectory of costs to fundamental plausible component cost reductions. E3's trajectory of capital costs results in a **26% cost reduction** between 2013 and 2030.

+ For **wind**, E3 applies a learning rate of 10% to the IEA's forecast of global installations. The resulting learning curve suggests a 9% reduction in wind capital costs between 2013 and 2030.

The resulting technology cost projections for solar PV, solar thermal, and wind are shown in Figure 9.

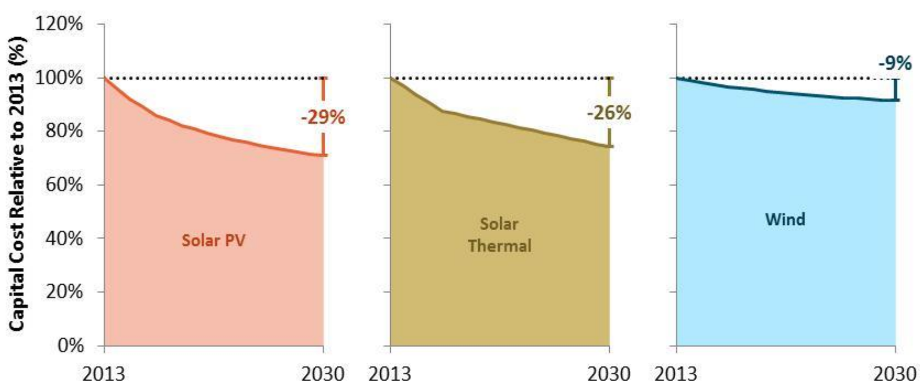


Figure 9: Assumed trajectories of solar and wind capital costs over time

This study assumes that the costs of other renewable technologies—biogas, biomass, geothermal—would remain stable over time. Compared to the emerging technologies, the other technologies have reached a level of maturity to justify this assumption.

In addition to the presumed changes in capital costs for emerging renewable technologies, there are several other factors that could have substantial impacts on the prices at which renewables are procured in the future. As a general rule, E3 assumes that tax incentives remain in place unless a specific sunset date is included in statute. If the statute includes a specific sunset date, E3 assumes that the incentive expires on that date.

E3 has identified the following factors as being the most significant:

+ **Sunset of federal tax credits:** The federal Investment Tax Credit (ITC) and Production Tax Credit (PTC) are both scheduled to expire: the 30% ITC is currently scheduled to expire at the end of 2016, at which point it would revert to its prior level of 10%; the PTC will expire if not renewed at the end of 2013. For the sake of consistency across resources, E3 assumes that PTC expiration and ITC reversion to 10% both occur at the end of 2016.
+ **Expiration of California property tax exemption:** Solar PV systems installed in California before the close of 2016 are eligible to claim exemption from property taxes. E3 assumes this exemption expires at the end of 2016, per current statute.
+ **Expiration of 'bonus' depreciation:** Eligible renewable resources installed before December 31, 2013 may qualify for bonus depreciation, which allows for the owner to depreciate 50% of the asset in the first year and the other 50% according to a traditional MACRS depreciation schedule. E3 assumes this provision expires at the end of 2013, per current statute.

- **Low interest rates:** The current, low-interest rate environment is very favorable to the type of long-term debt tenor that is needed to finance capital-intensive renewable energy projects. However, in the past, interest rates have fluctuated depending on economic conditions, with many periods in which interest rates are significantly higher than today. This study assumes that today's low interest rates are temporary, and that the weighted average cost of capital increases from 7.10 - 7.25% in 2013 to 8.10 - 8.30% by 2018, more in keeping with long-term trends.

In combination, these factors result in substantial changes to renewable costs over time. Figure 10 shows year-by-year trajectories of PPA prices for the technologies considered in this study. The subsequent Figure 11 shows how each of these factors contributes to the difference between PPA prices for a system installed today and one installed in 2030 for a subset of these technologies.

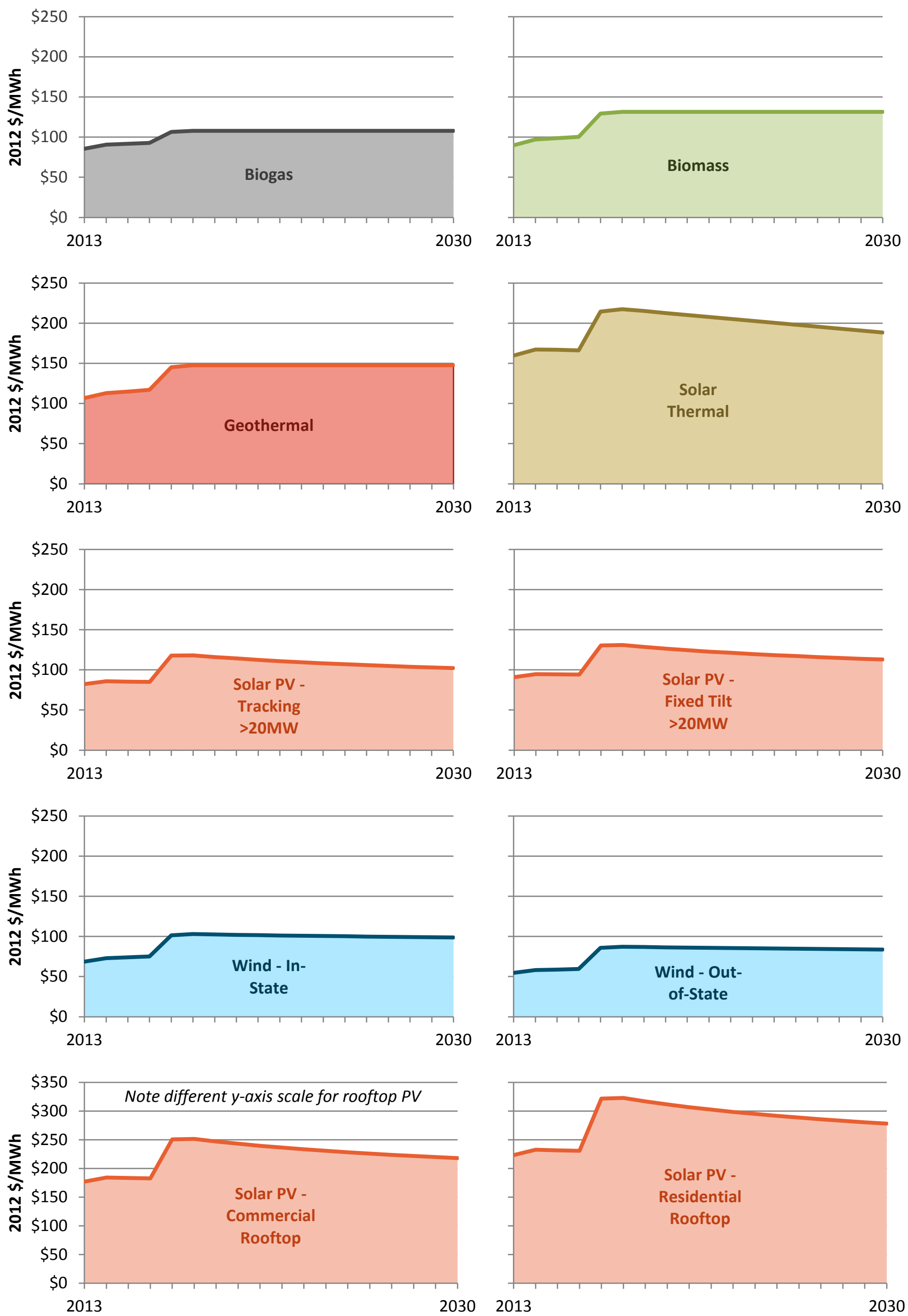


Figure 10: Trajectories of cost-based PPAs for renewable resources by installation vintage

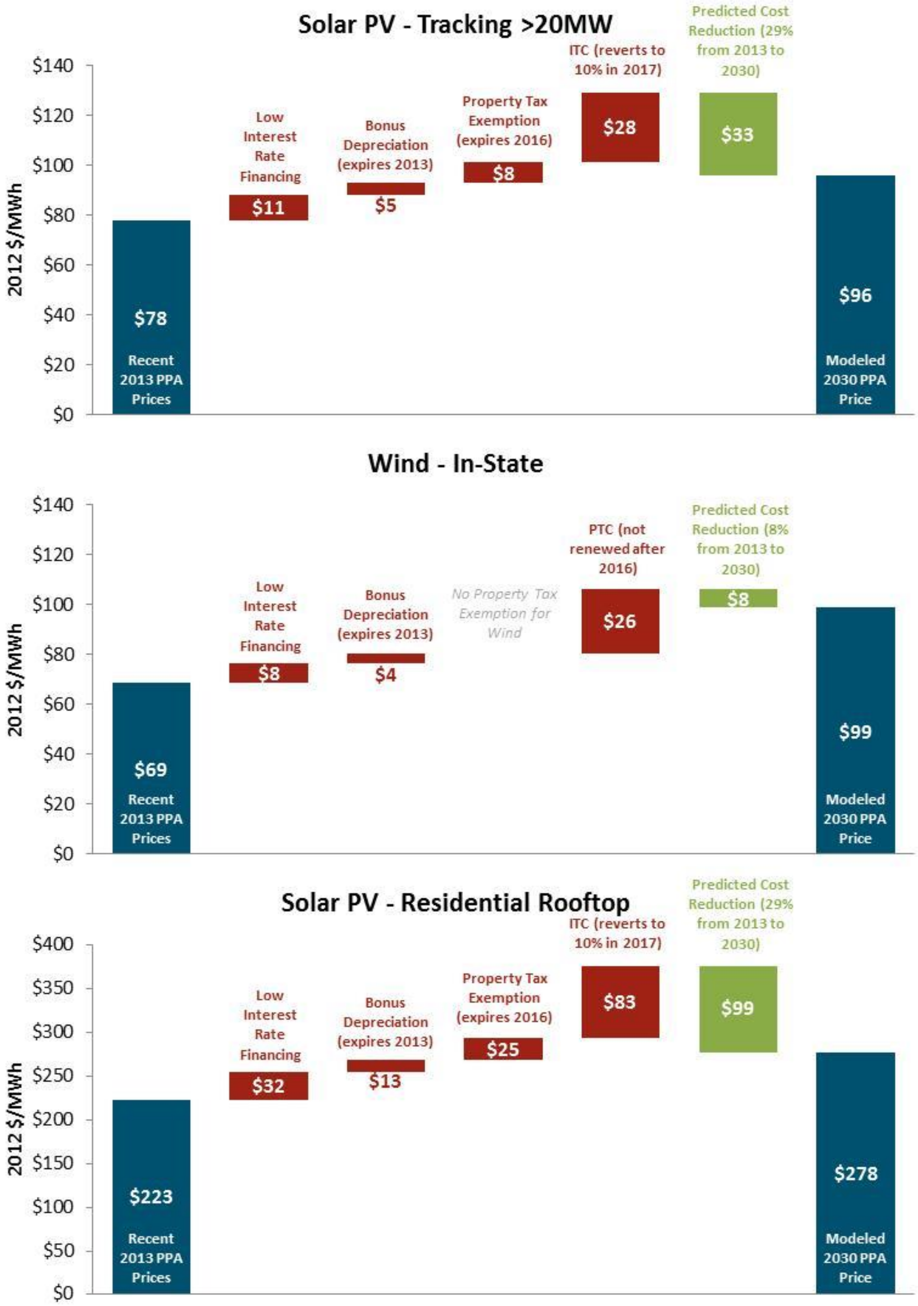


Figure 11: Major changes to PPA prices from 2013-2030, solar PV and wind resources

2.5.1.3 Renewable Resource Cost Sensitivities

The trajectory of capital costs in the future is a key uncertainty in estimating the cost of achieving a 50% RPS. In order to develop a robust set of sensitivities to capture a wide range of plausible futures, this study considers High and Low Cost sensitivities based on alternative assumptions of the cost reductions for solar PV, solar thermal, and wind. In the High Renewable Cost sensitivity, all costs are assumed to remain constant in real terms from 2013 forward. In the Low Renewable Cost sensitivity, all cost reductions are doubled (e.g. the 29% reduction in solar PV costs by 2030 in the Base Case is a 58% reduction in the Low Renewable Cost sensitivity). The Low Renewable Cost sensitivity captures the potential for a breakthrough in solar technologies, yielding capital costs comparable to the DOE Sunshot goal of $1/W for solar PV by 2030. These alternative trajectories are shown in Figure 12.

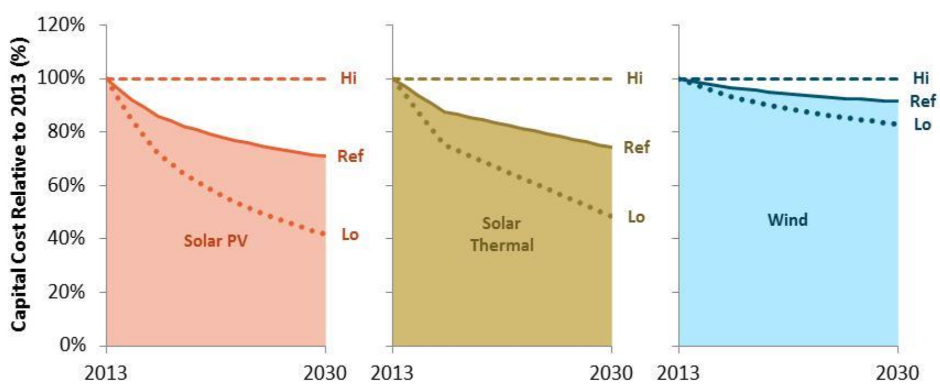


Figure 12: Capital cost trajectories used to derive high and low renewable cost sensitivities ("Hi" and "Lo", respectively)

2.5.1.4 Summary of Resource Costs

This section presents the calculated cost-based PPA prices for each renewable technology for installation vintages of 2013, 2020, and 2030. Table 19 presents capital costs and PPA prices for the reference case assumptions, for resources installed in 2013, 2020 and 2030. Table 20 displays the High Renewable Cost and Low Renewable Cost sensitivities, respectively.

Table 19: Reference Case renewable resource capital costs and LCOEs over time (all costs in 2012 $; capital costs for solar PV are reported relative to the plant's DC nameplate capacity).

Technology	Capital Cost *($/kW)*			LCOE *($/MWh)*		
	2013	2020	2030	2013	2020	2030
Biogas	$3,040	$3,040	$3,040	$ 85	$ 108	$ 108
Biomass	4,974	4,974	4,974	90	131	131
Geothermal	6,080	6,080	6,080	107	148	148
Hydro - Small	4,238	4,238	4,238	157	241	241
Solar PV - Residential Rooftop	4,165	3,362	2,951	223	311	278
Solar PV - Commercial Rooftop	3,123	2,521	2,213	177	243	218
Solar PV - Fixed Tilt < 20 MW	2,643	2,133	1,873	103	142	127
Solar PV - Fixed Tilt > 20 MW	2,357	1,903	1,670	91	126	113
Solar PV - Tracking < 20 MW	3,000	2,422	2,289	92	128	114
Solar PV - Tracking > 20 MW	2,692	2,235	2,126	82	114	102
Solar Thermal - No Storage	5,370	4,539	3,986	164	216	192
Solar Thermal - Six Hour Storage	7,780	6,577	5,775	160	213	188
Wind - In-State	2,111	2,006	1,930	69	102	99
Wind - Out-of-State	1,963	1,866	1,795	54	86	83

Table 20: Renewable resource capital costs and LCOEs for resources installed in 2030 for the Reference Case and High and Low Renewable Cost sensitivities (all costs in 2012 $; capital costs for solar PV are reported relative to the plant's DC nameplate capacity)

Technology	Capital Cost *($/kW)*			LCOE *($/MWh)*		
	Ref	High Cost	Low Cost	Ref	High Cost	Low Cost
Biogas	$3,040	$3,040	$3,040	$ 108	$ 108	$ 108
Biomass	4,974	4,974	4,974	131	131	131
Geothermal	6,080	6,080	6,080	148	148	148
Hydro - Small	4,238	4,238	4,238	241	241	241
Solar PV - Residential Rooftop	2,951	4,165	1,737	278	377	179
Solar PV - Commercial Rooftop	2,213	3,123	1,303	218	292	144
Solar PV - Fixed Tilt < 20 MW	1,873	2,643	1,103	127	172	83
Solar PV - Fixed Tilt > 20 MW	1,670	2,357	983	113	153	73
Solar PV - Tracking < 20 MW	2,289	3,000	1,252	114	154	74
Solar PV - Tracking > 20 MW	2,126	2,692	1,123	102	138	66
Solar Thermal - No Storage	3,986	5,370	2,602	192	252	132
Solar Thermal - Six Hour Storage	5,775	7,780	3,770	188	249	128
Wind - In-State	1,930	2,111	1,749	99	106	91
Wind - Out-of-State	1,795	1,963	1,627	83	89	77

2.5.2 GAS-FIRED GENERATION COST ASSUMPTIONS

E3 also calculates the cost to utilities of contracting with new fossil generation that is either currently planned or under construction as well as that which is required to maintain system reliability in each scenario. E3 relies upon cost and performance assumptions for various gas-fired generation technologies that were developed in E3's *Cost and Performance Review of Generation Technologies*; in order to ensure accuracy, the inputs were compared with assumptions presented at recent public workshops on the cost of fossil-fueled generation in California hosted by the California Energy Commission[34] and were deemed to be reasonably representative of the cost of building new gas-fired generation in California.

The input assumptions for three gas technologies—a combined cycle gas turbine (CCGT), an aeroderivative combustion turbine (CT), and a frame combustion turbine—are shown in Table 21. E3 uses the same cash flow financing model developed to price renewable generation to derive levelized fixed costs for each of these types of units that would provide a third-party developer with a full return of and on equity over the plant's lifetime. The assumptions shown in this table are applied to plants installed in all years over the study horizon; these generation technologies are mature enough that E3 assumes that no meaningful changes to natural gas capital costs will occur over the study's horizon.

Table 21. Cost and performance assumptions of new gas-fired generation (2012 $)

Technology	Capital Cost *($/kW)*	Fixed O&M *($/kW-yr)*	Variable O&M *($/MWh)*	Heat Rate *(Btu/kWh)*	Levelized Fixed Cost *($/kW-yr)*
Combined Cycle Gas Turbine	$ 1,266	$ 18	$ 5	7,000	$ 220
Combustion Turbine - Aero	$ 1,239	$ 20	$ 5	9,300	$ 218
Combustion Turbine - Frame	$ 949	$ 12	$ 5	12,000	$ 163

[34] Presentations from CEC workshop available at:
http://www.energy.ca.gov/2013_energypolicy/documents/2013-03-07_workshop/presentations/

2.6 Key Assumptions and Data Sources

This study, like other large-scale quantitative modeling efforts, requires a large quantity of input data and assumptions. This section discusses the data and assumptions that are likely to be of greatest interest to readers. Additional information about data and assumptions are included in the technical appendix.

2.6.1 STUDY AREA

The Study Area considered for this report includes the physical footprint of the California ISO, Balancing Authority of Northern California (BANC, operated by SMUD) and LADWP Balancing Authority Areas (BAAs). The loads modeled include the Bundled, Direct Access (DA) and Community Choice Aggregation (CCA) loads in the utility service areas as well as the loads served by embedded municipal and cooperative utilities. California loads in the Turlock Irrigation District, Imperial Irrigation District and PacifiCorp BAAs are excluded from the study. The REFLEX modeling is conducted for the entire Study Area; internal transmission constraints and other barriers to optimal operations within the Study Area are ignored. Revenue requirement and average rate estimates are presented for the Study Area.

2.6.2 RESPONSIBILTY FOR RENEWABLE RESOURCE BALANCING

In each scenario, the resource portfolio meets the target RPS with fully-delivered renewable electricity, which is assumed to be balanced by California. Out-of-state resources under long-term contract to California utilities are assumed to remain in the California portfolio through 2030; however, they are balanced using California resources. Unbundled renewable electricity credits, which require other regions to balance the renewable power, are not included in the analysis.

2.6.3 LOAD FORECAST

This study relies on the California Energy Commission's (CEC) *California Energy Demand 2012 – 2022 Final Forecast*, which provides peak and energy forecasts through 2022 and supports the CEC's Integrated Energy Policy Report (IEPR). We use the *mid energy demand case* for the CAISO, LADWP and BANC balancing authorities, and project final retail sales through 2030 by decomposing the CEC forecast into three components: (1) retail sales excluding behind-the-meter solar PV and electric vehicle consumption, and including uncommitted energy efficiency impacts; (2) electric vehicle consumption; and (3) incremental behind-the-meter solar PV generation.

The first component is projected through 2030 by applying the average growth rate over the 2017 - 2022 forecast period (0.4% per year). Electric vehicle energy consumption is assumed to grow linearly between 2022 and 2030. The current net energy metering cap for behind-the-meter solar PV is assumed to reach 7,000 MW by 2030, resulting in 10,400 GWh of annual behind-the-meter solar PV generation.

The forecast of the 1-in-2 peak demand in 2030 includes the same components and approach as the retail sales forecast, except that the peak demand impact of electric vehicle recharging is based on an EV load profile, which assumes that most vehicle charging occurs at night, consistent with current trends. Figure 13 shows the changes to the study area load from 2012 - 2030. Retail sales and peak demand grow at an annual average rate of 0.4% per year, after adjustments for energy efficiency, electric vehicle consumption and behind-the-meter solar PV are accounted for.

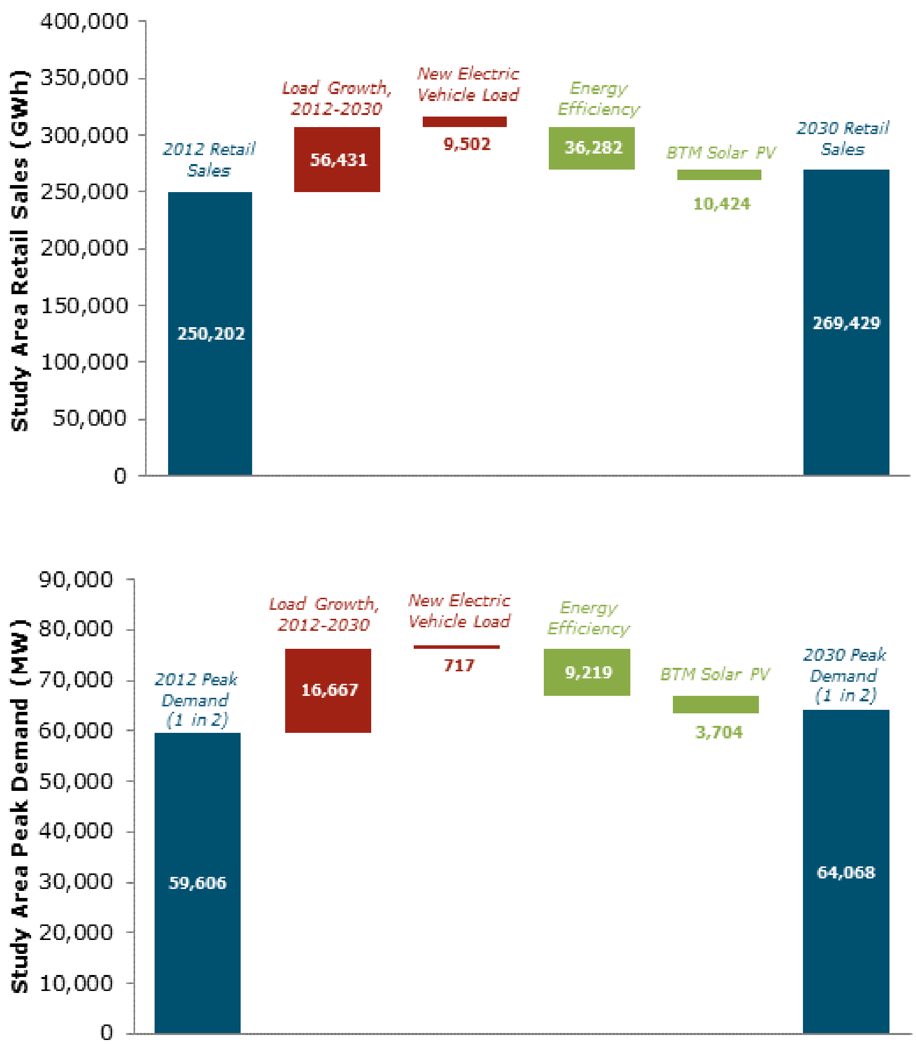


Figure 13: Changes to Study Area load, 2012 – 2030 for (top) retail sales and (bottom) peak demand

2.6.4 CHANGES IN THE COMPOSITION OF CALIFORNIA'S THERMAL GENERATION FLEET

This study models the operations of the combined Study Area system as it might exist in 2030. The system that is modeled looks much different from the system that exists today, reflecting utilities' current assumptions regarding planned changes to the thermal generation mix in California. These assumptions include (but are not limited to):

- Retirement of 14,334 MW of natural gas-fired generators that use once-through cooling;
- Displacement of 1,652 MW of out-of-state coal-fired generation that currently serve California ratepayers;
- Construction of 2,500 MW of combined-cycle gas turbine (CCGT) resources and 1,000 MW of simple-cycle combustion turbine (CT) resources in the SCE service area to meet Local Capacity Reliability (LCR) needs;
- Construction of 2,876 MW of CCGTs and CTs to replace once-through-cooling units, primarily in LADWP;
- Construction of 1,680 MW of CCGT resources in Utah and Arizona to replace coal generation that currently serves customers of LADWP and SCPPA utilities.

These resources provide baseload and flexibility services to meet the increasing needs of the grid in 2030. While many of these resources are already in the planning stages and some have received approvals from the appropriate regulatory authorities, not all of the resources have been approved as of this writing. The following table lists the retirements and replacement resources assumed for this study.

Table 22: Retirement and new build assumptions behind 2030 thermal resource portfolio

	Capacity (MW)
2012 Thermal Resources	47,644
Changes between 2012 and 2030	
SONGS Retirement	*-2,150*
OTC Retirements	*-14,334*
Coal Contract Expiration	*-1,652*
Other Retirement	*-2,797*
Planned Additions	*+5,050*
OTC Replacement	*+2,876*
Coal Contract Replacement	*+1,680*
LCR Additions	*+3,500*
Total	-7,827
2030 Thermal Resources	39,816

The thermal fleet assumed for the 2030 RPS scenarios is shown juxtaposed with the 2012 thermal fleet for the study area in Table 23. Cogeneration resources are forecast to show no net increase by 2030, which may underestimate the cogeneration build-out if current policy goals to support increased cogeneration in the state succeed. Cogeneration resources are modeled as baseload, must-run and so do not contribute to the system's thermal flexibility capabilities.

By 2030, significantly less total thermal generation is expected to be operating in California, both in terms of nameplate capacity and energy generated. This is due to a combination of factors: low load growth, increased renewable generation and the changing composition of the thermal generation fleet. The most striking shift in the thermal fleet expected from 2012 to 2030 is the replacement of steam turbines (once-through-cooling steam plants in particular) with combined cycle units and combustion turbines.

Table 23. Changes in the thermal fleet composition by technology assumed between 2012 and 2030 (MW)

Thermal Resources (MW)	2012	2030	Change (2012 to 2030)
Nuclear	5,473	3,323	-2,150
Coal	1,652	0	-1,652
Cogeneration	2,779	2,779	0
Gas - Combined cycle	16,568	23,928	7,360
Gas - Combustion Turbine	5,745	9,545	3,799
Gas - Steam Turbine	15,214	30	-15,184
Gas - Internal Combustion	213	213	0
Total	**47,644**	**39,816**	**-7,827**

This shift has two primary flexibility implications. Combined cycle units typically have higher minimum stable output levels than steam turbines (40% of maximum capacity, as compared to 20% for steam turbines). The thermal fleet in 2030 therefore has a higher average minimum stable level than the 2012 thermal fleet, given the same power output. This is reflected in the average natural gas unit statistics listed in Table 24. This shift toward higher minimum stable levels has the potential to exacerbate downward flexibility problems by increasing the thermal generation levels required to provide the same level of reserves.

The second flexibility impact between the thermal fleets in 2012 and 2030 is the improved ramping capability of the system due to the growth of the combustion turbine fleet. Combustion turbines can ramp approximately 5-10% of their maximum capacity per minute while steam turbines and combined cycle units in today's stack can ramp only 1-2% of their maximum capacity each minute. The average natural gas unit in the 2030 fleet used for this analysis therefore has approximately 60% higher ramping capability than the average unit in 2012. Though not significant for flexibility modeling, the 2030 fleet also has an average heat rate that is 10% lower than the 2012 average natural gas unit heat rate.

Table 24: Operating characteristics for the average natural gas unit in the 2012 and 2030 conventional fleets

Average Natural Gas Unit	2012	2030	Implication
Maximum Capacity (MW)	121	113	For reference only
Minimum Stable Level (MW)	44	53	Decrease in flexibility
Max. Ramp Rate, MW/min	2.4	3.8	Increase in flexibility
Heat Rate (Btu/kWh)	9,369	8,472	Increase in efficiency

2.6.5 MUST-RUN THERMAL GENERATION

The study assumes that some thermal resources must be operated at all times in order to meet local reliability requirements related to inertia and system stability. This study does not perform an assessment of local reliability needs; however, the following assumptions are applied regarding must-run thermal generation:

- 40% of the load in the SCE service area must be served with specified thermal generation located in SCE during all hours;
- 25% of load in the SDG&E service area must be served with thermal generation located in SDG&E during all hours; and
- 1,080 MW of thermal units operate as must-run from June through September in the SMUD service area.

These assumptions are based on current CAISO and SMUD operating rules, and may change over time under high RPS penetrations and as new resources or transmission are added to each local reliability region. The must-run generation is available to provide flexibility services, and is allowed to ramp down to minimum generation conditions as needed during system operations. However, the need for thermal generation contributes to overgeneration during certain conditions. This study does not assume any minimum level of thermal generation in the LADWP service area; to the extent that such generation is needed, this would increase the overgeneration relative to the results described in this report.

2.6.6 IMPORTS AND EXPORTS

California currently relies upon a large quantity of imported power to serve load reliably. These imports consist of "baseload" power scheduled from coal and nuclear resources owned by or contracted to California utilities, surplus hydroelectric generation from the Northwest, and economic imports of natural gas power from the Northwest and Southwest. During some hours, California imports as much as 12,400 MW of power over its interties with the rest of the Western Interconnection. California also currently exports a small amount of power to the Pacific Northwest during some hours in the wintertime; however, these exports are more than offset by imports from the Southwest, such that California is never a net exporter of power.

This study assumes that in 2030, California can continue to import up to 12,400 MW of power as needed to meet load reliably. It also assumes that California can export up to 1,500 MW to its neighbors, based on maximum historical exports to the Northwest (assuming that California generation can substitute for imports from the Southwest). This assumption is based on an assessment of current transmission operating capabilities and does not account for institutional barriers or market conditions that might prevent California from becoming a net exporter of 1,500 MW of power by 2030.

Changes in the composition of the portfolio of resources serving California loads are likely to substantially change the way that power flows across the Western Interconnection. Displacement of coal resources will reduce imports from the Southwest, while the increased quantity of must-run, renewable generation inside California will reduce the demand for imports from the Northwest. This study finds that there will likely be many hours when California has excess generation that could be exported. One of the integration solutions modeled explores the effectiveness of increased coordination between California and other regions in reducing integration costs, allowing California to export up to 6,500 MW of power.

2.6.7 LOAD SHAPES AND INTERACTIONS WITH RATE DESIGN

This study uses a database of daily weather- and solar-matched load shapes, reflecting 63 years of historical variability in load and weather in California. The historical load shapes were modified to reflect the impacts of future levels of behind the meter rooftop solar and electric vehicle charging. The assumed electric vehicle charging shape is based on current charging patterns, predominated by night-time controlled charging using time-of-use rates, with some expansion in daytime charging using a mix of “fast” and “slow” charging.

The ways in which future end uses will change current patterns of electricity demand in California is uncertain, and cannot be fully captured in this analysis. Future electricity rate design, such as time-of-use rates, inclining block rates and dynamic pricing, can be used as a tool to influence how and when electricity is used. Future rate design could thus either exacerbate or alleviate renewable integration and flexibility challenges, depending on how it is used.

Other factors, such as shifts in industry and economic growth patterns, the expansion of commercial “server farms”, and environmental factors like climate change, will all contribute to changing patterns of electricity demand. To the extent that the saturation of air conditioning becomes more prominent, for example, the shape of the state’s load pattern could shift, pushing the peak demand period farther into the evening. The impact of more responsive, flexible loads is evaluated as one of the potential solutions to the renewable integration and flexibility challenge.

2.6.8 BEHIND THE METER SOLAR AND NET ENERGY METERING

The study assumes that behind-the-meter solar PV installations continue through 2030 in all scenarios, resulting in a cumulative total of 7,000 MW of behind-the-meter solar by 2030 in all scenarios. This level is approximately consistent with the current cap on net energy metering (NEM) in the state. The study assumes that once the current NEM cap is reached, all additional rooftop PV is procured at cost through a power purchase agreement and no additional net energy metering occurs.

The behind-the-meter solar PV is treated for RPS compliance purposes as a load reduction rather than a resource, and as such does not count towards meeting the state's RPS, consistent with current policy. The Rooftop Solar Scenario includes 15,300 MW of additional rooftop solar that is treated as a generation resource at the distribution level, and which is assumed to contribute towards meeting the state's RPS in 2030.

The direct procurement cost of the 7,000 MW of net metered, behind-the-meter solar PV is assumed to be borne by the customer, and as such is not reflected in the resource procurement costs in this study. The reduction in retail sales associated with these installations serves to increase the average retail rate; this means that the study implicitly assumes that NEM PV is reimbursed at the average retail rate. Currently, NEM PV installations are reimbursed at much higher rates due to inclining block retail rate designs with very high top-tier rates, particularly for residential customers of investor-owned utilities. The retail rates calculated for this study do not account for this.

NEM solar PV also contributes to the distribution system costs and benefits calculated in this study. Additional RPS-eligible rooftop PV is evaluated in a manner consistent with all other renewable resources, i.e., by assuming a cost-based PPA with a third party developer. The study does not estimate the rate impact of alternative rooftop PV procurement policies such as feed-in tariffs or net energy metering that deviate from the assumption of cost-based PPAs.

2.6.9 NATURAL GAS AND CO_2 PRICE ASSUMPTIONS

The base case price of natural gas delivered to electric generators in 2030 is assumed to be \$6.06/MMBtu (2012 \$). This is the Henry Hub natural gas price from the Energy Information Administration's (EIA) 2013 Annual Energy Outlook adjusted for basis differentials, delivery tariffs and municipal surcharges. Since natural gas prices are highly uncertain, this study includes a wide range for a low and high natural price sensitivity of \$3.00/MMBtu and \$10.00/MMBtu, respectively.

The study assumes a \$50.38/metric ton (2012 \$) CO_2 allowance price for fossil generating units in 2030, based on the CPUC's Market Price Referent (MPR) forecast. Since the CO_2 allowance prices are also extremely uncertain, a wide range of low and high CO_2 price sensitivities are applied, which reflect a forecast of current California Air Resource Board (CARB) cap and trade policies for the price floor at \$22.10/ton and the 3rd Tier Reserve Price at \$110.40/ton by 2030.

3 Investigation of Flexibility Needs under High RPS

3.1 Introduction

This study utilizes REFLEX on the ProMaxLT production simulation platform to investigate the operational and flexibility requirements under various renewable portfolios and with several integration solutions. This section describes the REFLEX for ProMaxLT modeling and results for 33%, 40%, and 50% RPS scenarios in order to provide insight into the flexibility challenges that are experienced by the bulk system with increased renewable penetrations. Following an analysis of the most critical flexibility challenges in meeting a 50% RPS, REFLEX for ProMaxLT modeling results are presented for the 50% RPS Large Solar Scenario with various integration solutions. The integration solutions evaluated here include: inter-regional coordination; conventional demand response; advanced demand response/flexible loads; energy storage; and renewable resource diversity.

3.2 The REFLEX Model

REFLEX is a stochastic production simulation model that characterizes the expected frequency, magnitude and duration of flexibility shortages corresponding to the four flexibility challenges:

1. **Expected Unserved Energy**: the expected quantity of firm load that cannot be served due to insufficient available resources;
2. **Expected Unserved Ramp in the downward direction**: expected shortage of downward ramping capability;
3. **Expected Unserved Ramp in the upward direction**: expected shortage of upward ramping capability; and
4. **Expected Overgeneration**: expected quantity of “must-run” generation that is greater than load plus exports.

REFLEX performs random draws of weather-correlated load, wind, solar and hydro conditions over a calendar day. The draws are taken from a very large sample of historical and simulated data, including 63 years of load data, 42 years of hydro data, and 3 years of wind and solar data. Utilizing ProMaxLT’s economic dispatch algorithms, it then calculates an optimal unit commitment and economic dispatch, beginning at the day-ahead commitment window and calculating economic dispatch down to the five-minute level. REFLEX thus considers operational needs associated with very high and very low load conditions, very high and very low hydro conditions, and a range of wind and solar conditions, as well as a broad distribution of the hourly and sub-hourly operating reserve requirements that have been referred to in previous studies as "load following."[35]

Flexibility violations are expressed in MWh per year, representing the total quantity of violations that are expected to occur in a given year. Cost penalties are assigned to each violation, and REFLEX calculates the total operational cost including fuel and O&M costs, the cost of emissions allowances, and the cost of flexibility violations. Cost penalties are based on the value of lost load (for upward violations) or the cost of procuring additional renewable energy (for downward violations).

3.3 Defining the Problem

3.3.1 FLEXIBILITY CHALLENGES AT A GLANCE

A simple comparison of hourly renewable energy production and electricity demand under the 50% RPS Large Solar Scenario shows that supply will exceed demand during many hours of the year. This "overgeneration" is the primary renewable integration challenge identified through this analysis. The analysis also finds that, under a high RPS, the seasons and times of day when system operations are likely to be most challenging shifts significantly, compared to conditions observed today. While planning for today's electric power system revolves largely around the need to meet peak demand, a system with 50% RPS must also be designed to accommodate the minimum net load, when low load

[35]GE Energy Consulting and California ISO, "Integration of Renewable Resources: Operational Requirements and Generation Fleet Capability at 20% RPS", 2010. <http://www.caiso.com/2804/2804d036401f0.pdf>

conditions are coincident with high renewable output, as well as to meet the potentially large upward and downward ramping events.

Increasing renewable penetration has a dramatic effect on the net load shape. Under a high RPS, the following system changes are observed:

- The peak net load period shifts, potentially to a smaller morning and evening peak, rather than a daytime peak period. “Net load” is defined as electricity demand minus renewable generation. Peak net load occurs when high load is coincident with low renewable generation. In the summer months, the effect of higher renewable penetration can shift the peak period from 3:00 PM with no renewables to 8:00 PM under high renewable penetration.
- The net load that must be served with dispatchable generation shows steep ramp periods in the morning and evening, which will require the availability of flexible resources.
- In the middle of the day, conventional resources may need to be shut down to accommodate low, or negative, net load conditions. Low net load conditions will need to be accommodated while also maintaining enough flexibility on the system to accommodate the evening ramp up.
- Negative net load conditions, in which renewable generation exceeds electricity demand, occur in the 40% RPS and 50% RPS Large Solar Scenarios.

These challenges are illustrated in Figure 14. The figure shows a low-load day in April, which in today’s system would pose no significant challenges to grid operators, but which under a high RPS experiences negative net loads and steep morning and evening ramps. The results of this study indicate that the challenges illustrated in the figure are not likely to be a unique or rare event, but are expected to occur consistently and frequently throughout a large portion of the year.

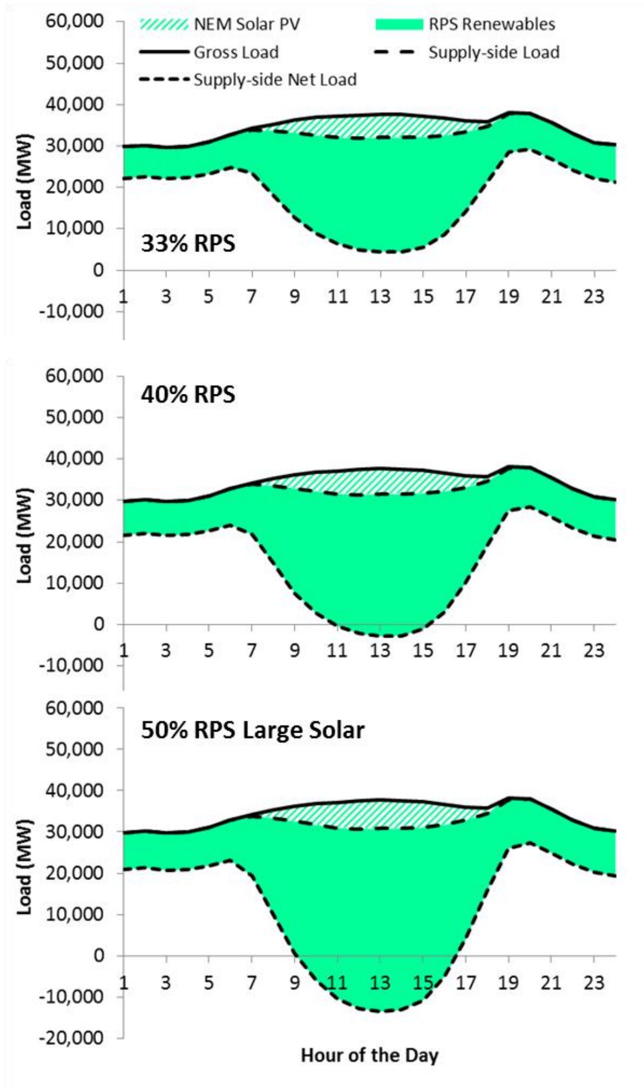


Figure 14: Supply-side load and net load on an April day with the 33% RPS, 40% RPS, and 50% RPS Large Solar portfolios

3.3.2 EXPLORATION OF POTENTIAL FLEXIBILITY ISSUES

As illustrated in Figure 14, there will be days under high renewable penetration when it will not be possible to avoid a flexibility violation. The system operator may, however, have some control over whether the system experiences an upward or downward violation. For example, Figure 14 shows an upward ramping requirement of approximately 35,000 MW between hour ending 13:00 and hour ending 19:00. If the system does not have sufficient upward flexibility to meet this required upward ramp, unserved energy may be experienced during the evening net peak hours. However, the system operator may be able to avoid this problem by curtailing solar energy during the afternoon in order to ease the ramp up to the evening net peak load. Thus, the system operator may have to choose between curtailing firm customer load during the evening hours and curtailing firm generation during the afternoon.

REFLEX modeling assigns cost penalties to the four types of flexibility violations discussed above in order to allow an economic tradeoff among violation types. This assignment of penalty values provides a “loading order” of flexibility violations. If the overgeneration penalty is very high, the system operator will attempt to maximize renewable energy deliveries, perhaps at the expense of unserved load. If the overgeneration penalty is very low, the system operator will prioritize avoiding unserved energy, at the expense of experiencing more overgeneration.

An initial set of REFLEX runs explores this tradeoff. In the first run, the cost of overgeneration is set very low relative to the cost of unserved energy, so the model turns on enough thermal units to ensure that no unserved energy occurs. As a consequence, a very substantial quantity of overgeneration is observed, amounting to 36% of total renewable generation. Figure 15 shows the dispatch on an example January day.

In a second REFLEX run, the cost of overgeneration is set higher than the cost of unserved energy in order to prioritize delivery of renewable energy. As seen in Figure 16, this has a significant impact on thermal dispatch on the example day. In contrast to the previous run, thermal units are scheduled to shut down as the sun rises in order to accommodate the solar ramp. This reduces the amount of reserves available to accommodate net load fluctuations and forecast errors. On the example day, unserved energy is observed during the morning hours as thermal units are shut down to make room for renewable generation, which appears later than expected (perhaps due to a lingering marine layer).

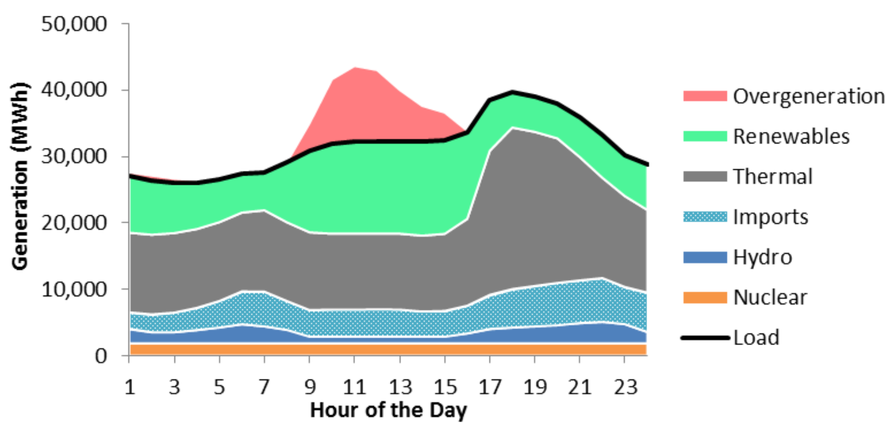


Figure 15: Generation mix on an example 50% RPS 2030 day with low cost renewable curtailment, resulting in significant amounts of thermal generation online during the middle of the day and high overgeneration

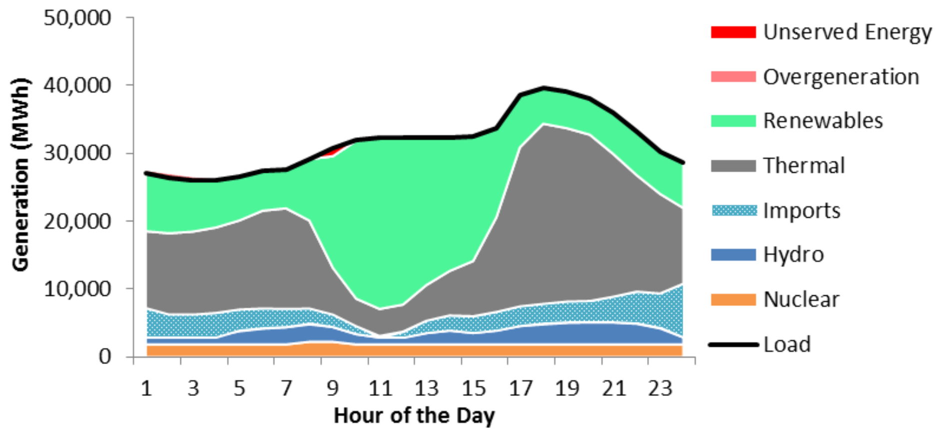


Figure 16: Generation mix on an example 50% RPS 2030 day with very high cost renewable curtailment, resulting in unserved energy due to minimal thermal generation during the morning ramp period leading to unserved energy but no overgeneration

While overgeneration is avoided during the example day, it should be noted that it cannot be avoided during all hours. Overgeneration during this run amounts to 13% of total renewable generation[36], despite the high penalty placed on it. This tradeoff between unserved energy and overgeneration is a key driver in this analysis. For the 50% RPS Large Solar scenario, test runs indicate that moving from a renewable delivery-prioritizing case to a case in which flexibility needs are prioritized and met entirely with conventional resources could increase expected overgeneration several-fold.

[36] This overgeneration exceeds the overgeneration found in the final 50% RPS Large Solar Scenario runs due largely to more conservative export constraints in the test runs.

3.3.3 DISPATCHABILITY OF WIND AND SOLAR RESOURCES

The modeling assumptions carried through the REFLEX runs in this analysis find a middle-ground between the two extreme cases described in Section 3.3.2. In all subsequent REFLEX runs, a very high penalty of $40,000 MWh is assigned to unserved energy[37], while a much lower penalty of $1,000/MWh is assigned to overgeneration. With these penalties, the model goes to extreme lengths to prioritize renewable energy deliveries – such as turning off all thermal units during daylight hours except those needed for reliability – while successfully serving load reliably by avoiding unserved energy.

Despite its high penalty price, overgeneration is unavoidable during many hours due to the magnitude of solar energy that is available during the daytime. This study assumes that managed curtailment of renewable generation occurs whenever total generation exceeds total demand plus export capability. This is critical to avoid too much energy flowing onto the grid and causing potentially serious reliability issues. Moreover, as indicated above, managed curtailment of renewable energy production may be needed to avoid curtailment of firm load due to lack of power system flexibility, for example, by helping to meet sharp upward or downward ramps or making room for additional operating reserves. Renewable curtailment is therefore treated as the "default" solution to maintain reliable operations.

For the purpose of calculating the revenue requirement associated with the each scenario, curtailment of renewable generation that is found to be

[37] LBNL, "Estimated Value of Service Reliability for Electric Utility Customers in the United States," June 2009. < http://certs.lbl.gov/pdf/lbnl-2132e.pdf >

necessary for grid operations is assumed to be compensated at the power purchase agreement (PPA) price. In addition, in order to ensure that each scenario achieves the assumed RPS target, additional renewable resources must be procured to compensate for the curtailed renewable energy production. The cost and other implications (e.g., change in fuel costs and GHG emissions) of this renewable “overbuild” are incorporated into the revenue requirement, but are not explicitly modeled in REFLEX.

3.4 System Operations under the 50% RPS Large Solar Scenario

This subsection presents results of REFLEX modeling for the 50% RPS Large Solar Scenario. The flexibility challenges associated with this scenario are described, and then a number of implications are drawn for operations under high RPS in general. Results of REFLEX runs for the solution scenarios are presented in Section 4.

The generation dispatch on a July day and on an April day for the 33% RPS, 40% RPS, and 50% RPS Large Solar Scenarios are shown in Figure 17 and Figure 18, respectively. For comparison, these same days are shown for each of the solution scenarios in Chapter 4. On the July high load day, we observe:

+ The renewable generation in each case significantly reduces the system’s reliance on thermal resources during peak conditions. The thermal generation required during the day is reduced moving from a 33% RPS to 40% RPS and to the 50% RPS Large Solar case.

- Under the 33% RPS portfolio, the net peak load occurs during the hour ending at 8:00 PM,[38] when the solar resource is deep into its evening ramp, while the gross peak load occurs during the hour ending at 4:00 PM.
- The net peak load is largely unchanged by increasing the RPS from 33% to 50% because renewable output is relatively low during peak net load conditions. This day qualitatively illustrates the declining capacity value of renewables at high penetrations that is described in Section 2.3.

Under high renewable penetration, operational challenges arise due to system flexibility limitations in non-summer months. On the April day, the system experiences both low load conditions and high solar output. While this type of day does not present planning challenges for today's system, the daytime conditions result in the potential for significant overgeneration with an RPS exceeding 33% when the renewable portfolio is dominated by solar resources.

Table 25 shows the differences in generation by technology type for three 2030 scenarios: the 33% RPS, 40% RPS and 50% RPS Large Solar Scenarios. The annual statistics show both decreasing utilization of thermal resources and increasing overgeneration with higher renewable penetration.[39]

[38] All times are listed in Pacific Standard Time (PST), i.e. unadjusted for day light savings time.
[39] It may be possible to avoid some renewable curtailment by turning off nuclear or cogeneration plants. This result has not been modeled here, as it would require more speculative changes to the operations of existing systems.

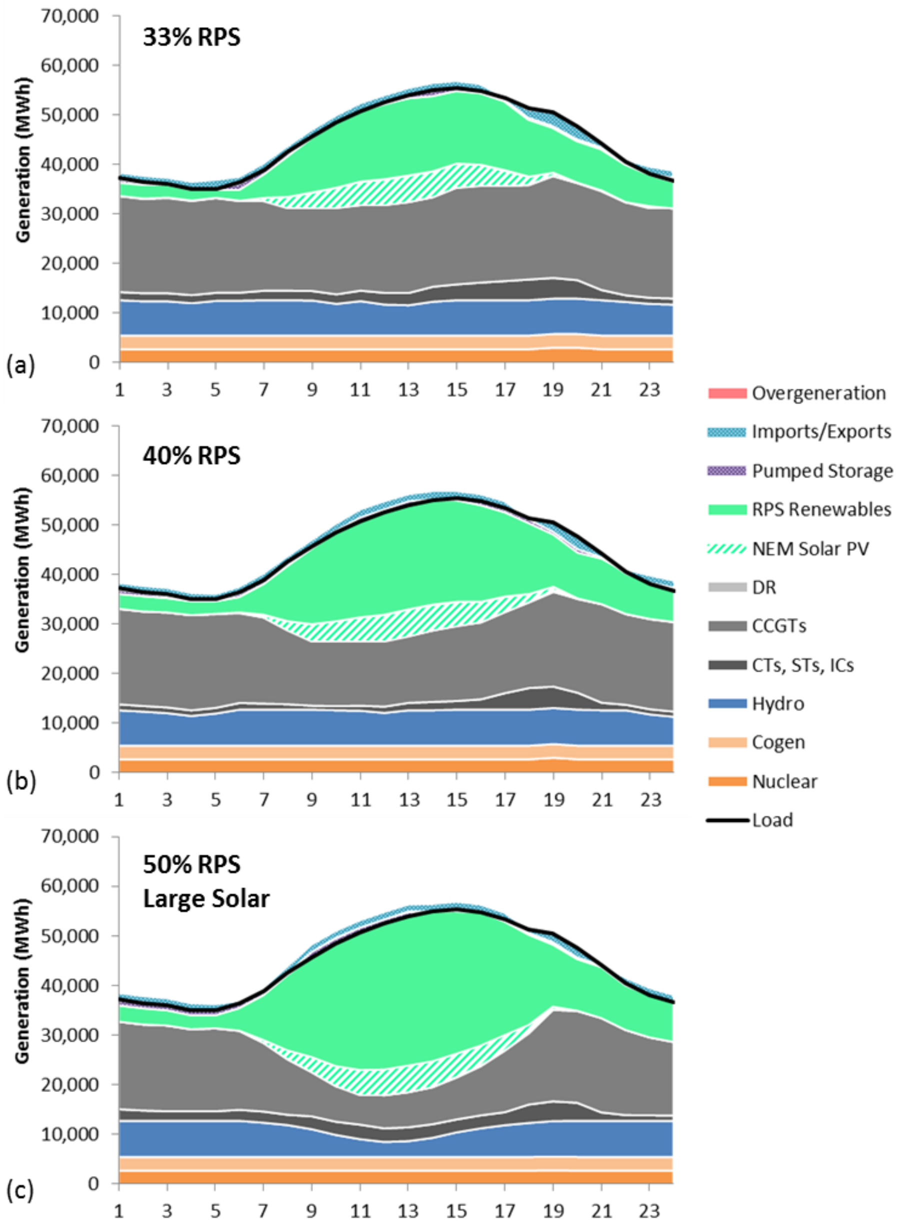


Figure 17: Generation mix calculated for a July day using REFLEX for ProMaxLT with the (a) 33% RPS, (b) 40% RPS, and (c) 50% RPS Large Solar portfolios showing no overgeneration or flexibility challenges

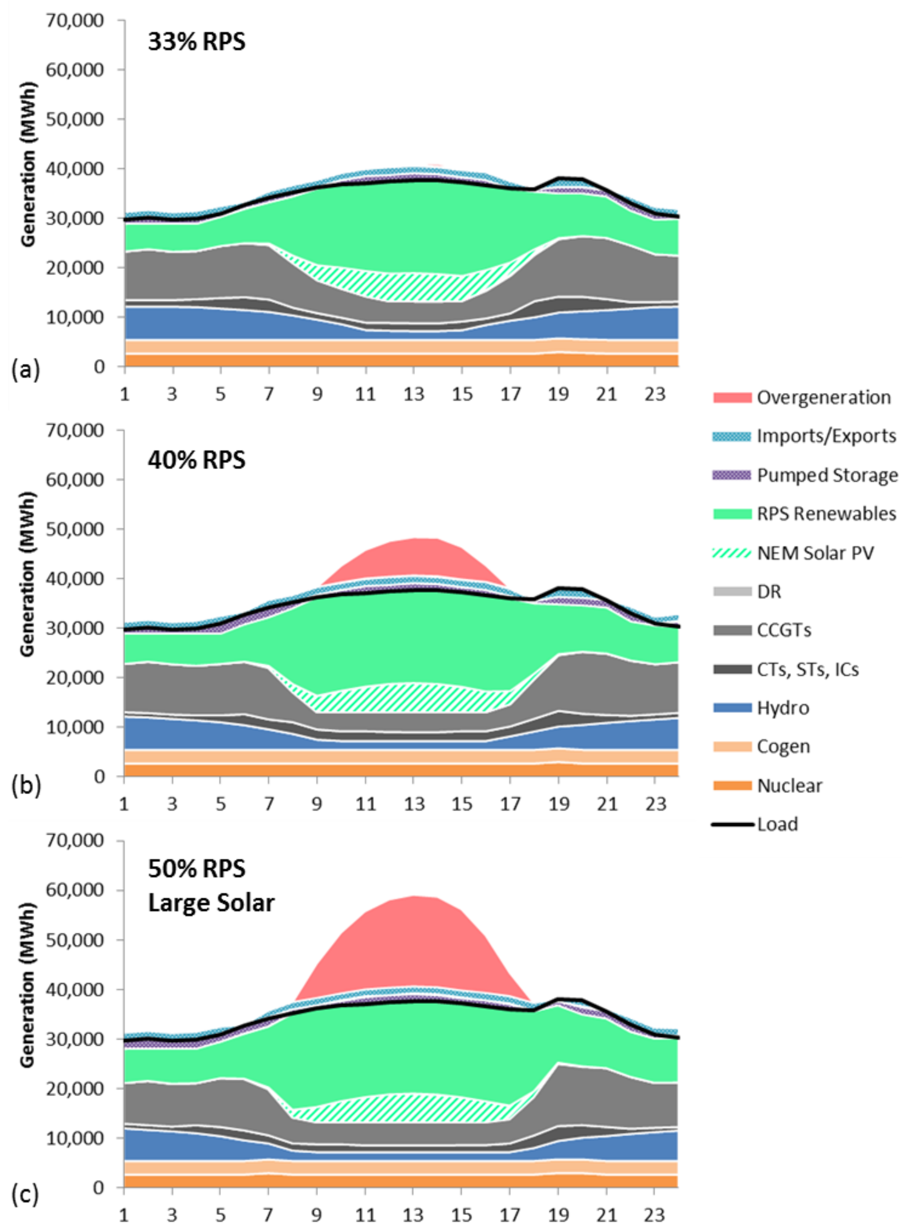


Figure 18: Generation mix calculated for an April day using REFLEX for ProMaxLT with the (a) 33% RPS, (b) 40% RPS, and (c) 50% RPS Large Solar portfolios showing significant overgeneration challenges

Table 25: Annual generation mix for the Study Area under three 2030 RPS scenarios[40]

Annual Supply-Side Equivalent Generation Mix, GWh/yr	33% RPS	40% RPS	50% RPS Large Solar
Conventional Fossil Resources	165,000	148,000	137,000
Conventional Non-Fossil Resources (Nuclear+Hydro)	61,000	59,000	53,000
Available RPS Renewables	90,000	109,000	136,000
Non-RPS Rooftop PV	11,000	11,000	11,000
Demand Response	-	-	-
Imports	2,600	2,900	3,100
Exports	-11,000	-10,000	-9,600
Overgeneration	-190	-2,000	-12,000
Total	320,000	320,000	320,000

3.4.1 OVERGENERATON AND RESOURCE CURTAILMENT

REFLEX ensures that adequate conventional resources remain online to avoid unserved energy. Instead, all flexibility violations are experienced as overgeneration, mitigated by resource curtailment. Figure 19 shows overgeneration “duration curves” – the quantity of overgeneration, in MW, for each hour of a year, sorted from highest the lowest hour of overgeneration. The duration curve shows on the x-axis the percentage of hours per year that overgeneration occurs, and on the y-axis the total MWs of overgeneration that are expected to occur for each scenario. The chart shows that both the frequency and the magnitude of overgeneration events increase with increasing RPS.

[40] Results are rounded to two significant figures or the nearest 1,000 GWh/yr

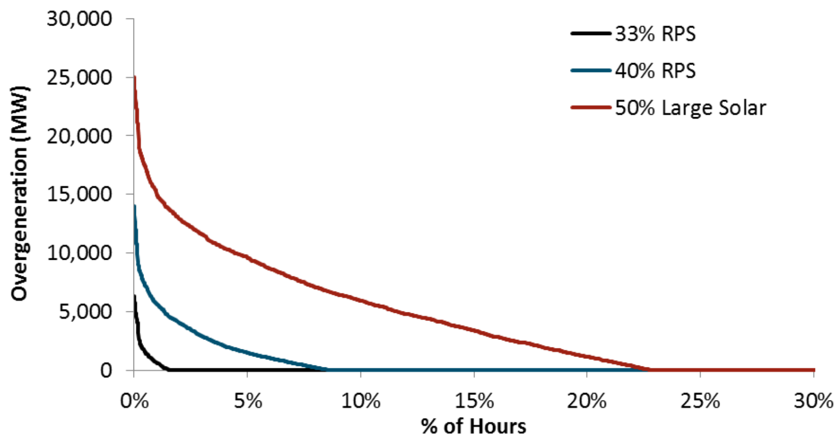


Figure 19: Duration curves of overgeneration events in 2030 RPS scenarios

Table 26 summarizes the overgeneration statistics for the 33%, 40% and 50% RPS Large Solar Scenarios. In the 33% RPS scenario, overgeneration occurs during 1.6% of all hours, amounting to 0.2% of available RPS energy. In the 50% RPS Large Solar case, overgeneration must be mitigated in over 20% of all hours and can reach 25,000 MW in some hours. Potential solutions or portfolios of solutions must therefore both be readily available during large portions of the year and must comprise a large total capacity.

The overgeneration events follow strong seasonal and diurnal trends, as is shown in Figure 20. Overgeneration is concentrated in daytime hours in the spring (and to a lesser extent in the fall) when the system experiences both low load conditions and high solar resource availability.

Table 26: Overgeneration statistics for the 33% RPS, 40% RPS and 50% RPS Large Solar Scenarios

Overgeneration Statistics	33% RPS	40% RPS	50% RPS Large Solar
Total Overgeneration			
GWh/yr.	190	2,000	12,000
% of available RPS energy	0.2%	1.8%	8.9%
Overgeneration frequency			
Hours/yr.	140	750	2,000
Percent of hours	1.6%	8.6%	23%
Extreme Overgeneration Events			
99th Percentile (MW)	610	5,600	15,000
Maximum Observed (MW)	6,300	14,000	25,000

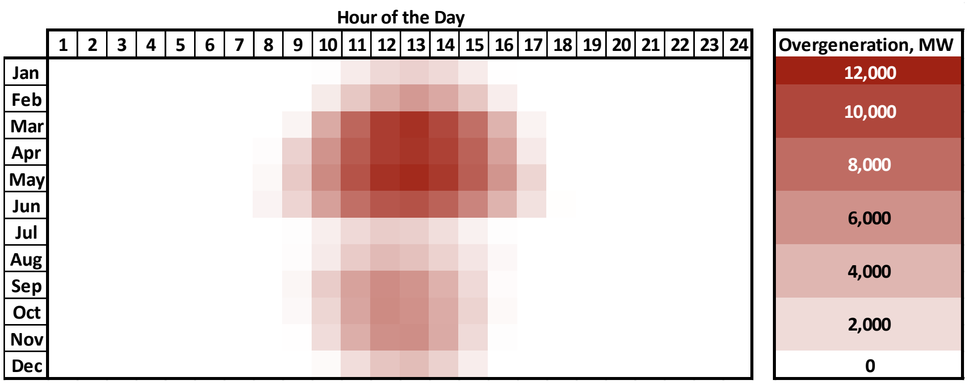


Figure 20: Average hourly overgeneration in the Study Area that must be mitigated by month-hour in the 2030 50% RPS Large Solar Scenario

3.4.2 MARGINAL OVERGENERATION AND RENEWABLE OVERBUILD

Renewables that generate during hours in which the system experiences overgeneration have diminished value. The *marginal overgeneration* is the fraction of the next increment (e.g. MWh) of renewable energy that cannot be delivered due to overgeneration conditions. The marginal overgeneration depends on the coincidence in time of renewable power output and the overgeneration already experienced on the system. It is therefore different for renewable technologies with different output shapes.

Table 27 lists the marginal overgeneration for various renewable technologies under the 33%, 40%, 50% RPS Large Solar and Diverse Scenarios. Marginal overgeneration increases for all technologies with increasing RPS, but the marginal overgeneration of solar technologies increases most rapidly. From 33% to 40% RPS, the marginal overgeneration of solar technologies increases from about 5% to 20-30% of incremental solar energy. Under the 50% RPS Large Solar Scenario, the marginal overgeneration approaches 60-70%.

Table 27: Marginal overgeneration (% of incremental MWh resulting in overgeneration) by technology for various 2030 RPS scenarios

Technology	33% RPS	40% RPS	50% RPS Large Solar	50% RPS Diverse
Biomass	2%	9%	23%	15%
Geothermal	2%	9%	23%	15%
Hydro	2%	10%	25%	16%
Solar PV - Large	5%	26%	65%	42%
Wind	2%	10%	22%	15%

The increasing marginal overgeneration with RPS level effectively translates into reduced capacity factors and, therefore, increased PPA prices for the next increment of renewable resources. The delivery-limited capacity factors – the capacity factors calculated by assuming that incremental renewables cannot generate during periods of overgeneration – are shown for wind and solar in each RPS scenario in Figure 21 and Figure 22, respectively. The marginal capacity factors shown here are used in the revenue requirement calculation for "overbuild" energy needed to replace curtailed renewables. Also shown for context are the average capacity factors of modeled resources in each scenario.

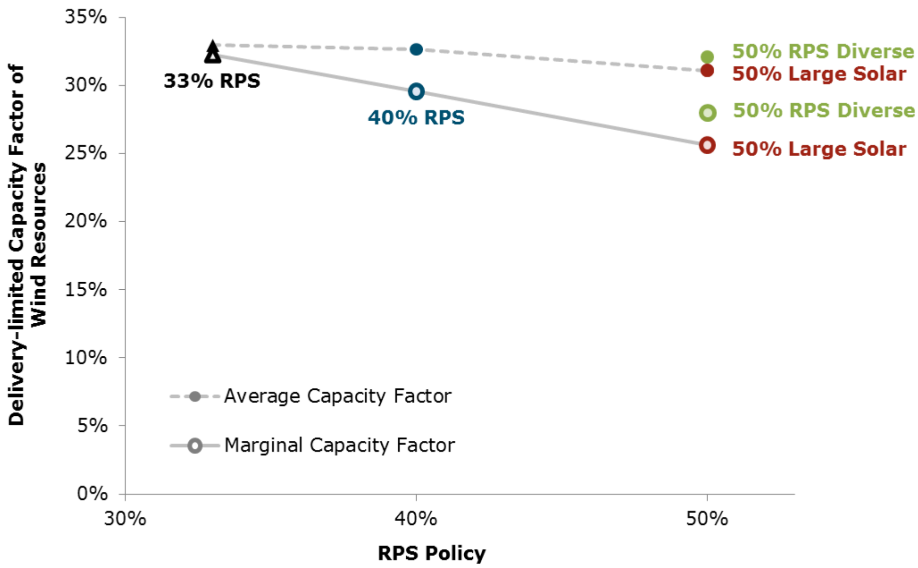


Figure 21: Marginal and average delivery-limited capacity factors for wind resources in each 2030 RPS scenario

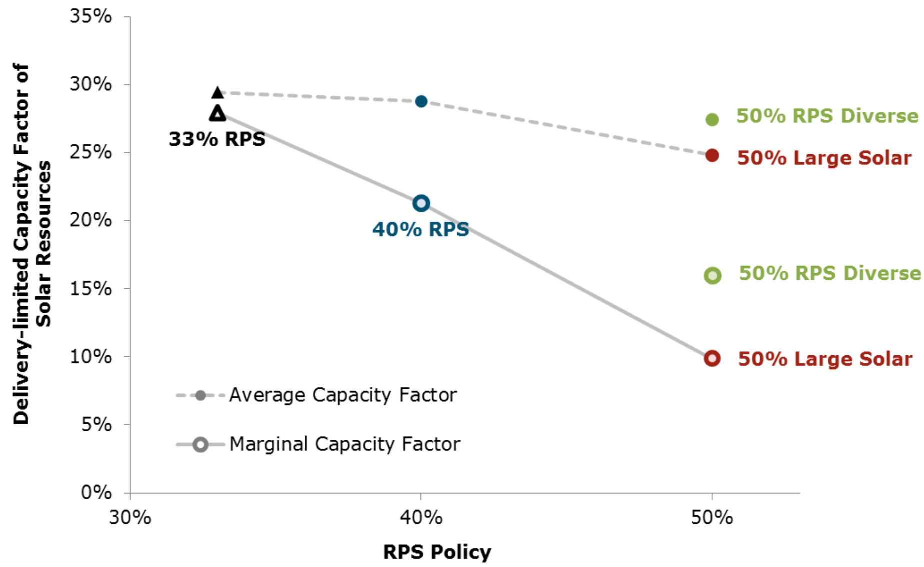


Figure 22: Marginal and average delivery-limited capacity factors for solar resources in each 2030 RPS scenario

3.4.3 THERMAL FLEET OPERATIONS

The pattern of daytime minimum net load conditions results in a diurnal cycling schedule for both CTs and CCGTs, in which units are frequently turned on at sunset and turned off at the following sunrise. The number of starts per year is roughly approximated for each unit in the 50% RPS Large Solar Scenario from the results of the REFLEX simulation in ProMaxLT.[41] Distributions of the expected number of starts per year are shown in Figure 23 and Figure 24 for

[41] REFLEX simulates operations over a wide range of system conditions using random day draws, as described in Appendix B. For the analysis of unit-specific operations, a subset of 28 representative days from the model dispatch are selected that collectively represent a wide range of system conditions. Weighting factors are calculated for each day by assuming that the day represents a reasonable approximation for operational trends over several days of the year. These weighting factors are calculated by linear regression to best match the load and renewable output distributions derived from the complete set of simulated days. For each unit, the number of starts per year is approximated by the weighted sum of the number of starts in each of the representative days.

CCGTs and CTs, respectively. The distributions suggest that most CCGTs start up less than once per day on average and that the most frequently cycling CT starts up on average about twice a day. It is important to note that more frequent cycling may occur on specific days depending on conditions.

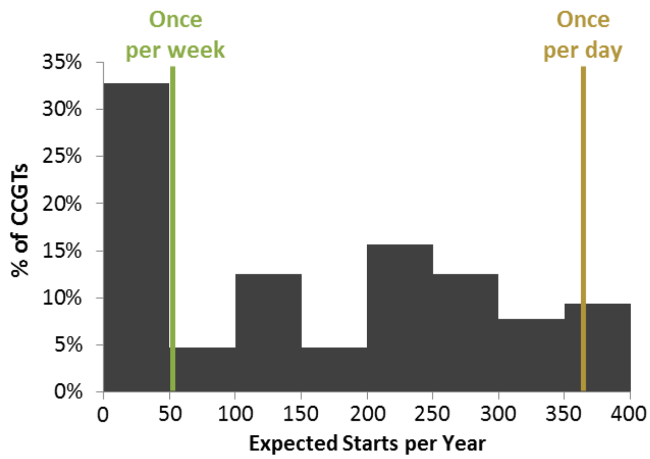


Figure 23: Approximate distribution of the expected number of starts per year among the fleet of CCGTs in the Study Area for the 50% RPS Large Solar Scenario

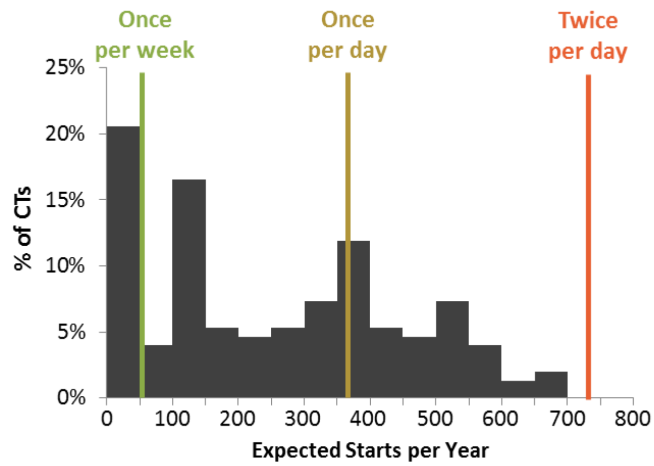


Figure 24: Approximate distribution of the expected number of starts per year among the fleet of CTs in the Study Area for the 50% RPS Large Solar Scenario

The ability of the thermal resources to cycle within the day provides significant operational flexibility. The performance of the conventional fleet on a day with significant upward ramping need is shown in Figure 25. The red line in this graph represents the total upward flexibility on the hourly level from the conventional resources. This upward flexibility can be provided by ramping up units that are committed in each hour, subject to their maximum ramping limits, or by turning on additional units that have met their minimum down time requirements. In the hour with the largest net load ramp, these combined flexibility options provide an additional 9,300 MW of ramping capability above the 11,600 MW required to meet the net load ramp.

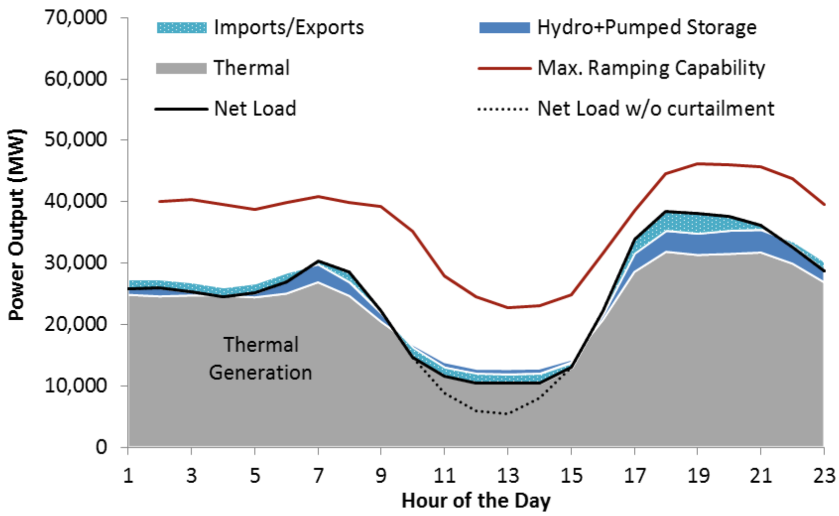


Figure 25: Conventional fleet performance and flexibility on the representative day with the largest net load ramp

As this extreme day suggests, the flexibility of the conventional fleet is found to be adequate to manage all observed upward net load ramps. One caveat to this conclusion is that REFLEX for ProMaxLT curtails renewable resources during the day to ease the evening ramp if the model encounters a ramp that exceeds the flexibility limits of the conventional fleet. This operational decision reflects the very high penalty price placed on unserved energy (which would be experienced as unmet upward ramp) compared with the lower penalty price placed on renewable curtailment. Despite this potential tradeoff, ramping needs are not identified as a significant driver of renewable curtailment in this analysis. Instead, renewable curtailment is overwhelmingly driven by must-run resources, local reliability constraints, and export limits.

While beyond the scope of this analysis, the cycling of thermal plants to accommodate a high RPS may increase both O&M costs and emissions and may not be permitted under today's air quality regulations. If these units are not able to cycle as frequently as is implied in Figure 23 and Figure 24, they may need to stay online throughout the day in order to avoid unserved energy, which would likely result in more overgeneration and renewable curtailment.

4 Investigation of Flexibility Solutions under High RPS

The default flexibility solution modeled for the Large Solar Scenario described above is managed, compensated curtailment of renewable energy output. This solution is necessary to ensure that overgeneration does not threaten reliable grid operations. This study considers five additional categories of flexibility solutions to evaluate the relative contributions of each solution to reducing overgeneration and renewable curtailment. These solutions include: enhanced regional coordination; conventional demand response; advanced demand response/flexible loads; energy storage; and renewable portfolio diversity. For each solution case, solutions are sized at 5,000 MW, to allow an "apples-to-apples" comparison among them. For the renewable portfolio diversity solution category, approximately 5,000 MW of solar from the 2030 50% RPS Large Solar Scenario is assumed to be replaced with a diverse mix of renewable technologies. An analysis of the optimal level of integration solutions to implement for each case was not possible within the scope of this analysis. The REFLEX for ProMaxLT modeling results from each solution case are described in this subsection.

Each solution is modeled to show its effects at reducing flexibility violations in the Large Solar Scenario. The Large Solar Scenario is utilized for this purpose because it represents a continuation of "business-as-usual" renewable energy procurement trends in California. The majority of renewable contracts signed in recent years have been with solar PV resources, based on cost and estimated value. However, it should be noted that the solutions modeled here for the Large Solar Scenario are equally applicable to the Small Solar, Rooftop Solar and Diverse Scenarios.

The solution quantities evaluated in these cases are informed by the size of the overgeneration caused by a 50% RPS, and not by any estimate of the feasibility or technical potential to achieve each solution. For example, we are not aware of any detailed studies of the technical potential for pumped storage or upwardly-flexible loads in California. Battery technologies have not been fully demonstrated as commercial systems in the types of applications or at the scale required to address the integration issues identified in this study. Regional coordination is promising but has progressed slowly over the past decade. There are likely to be significant challenges to implementing any of these solutions.

4.1 Solution Category A: Enhanced Regional Coordination

Enhanced regional coordination can help alleviate flexibility challenges in at least two ways. First, closer integration of operations between California and its neighbors may allow additional, latent generation flexibility that exists in other regions to contribute to meeting flexibility needs in California (and vice-versa). Various studies of an Energy Imbalance Market in the Western Interconnection have estimated that the benefits of such coordination can range from $50 million to several hundred millions of dollars per year under today's RPS targets, with much of the benefit resulting from reduced renewable integration costs.[42,43,44] This effect is approximated as a relaxation of hour-to-hour ramping constraints on power flows across the interties (in all other scenarios, hour-to-hour changes on intertie flows are not allowed to exceed historical levels).

Second, enhanced coordination can help California find markets in other states for its surplus energy that is available during hours with overgeneration conditions. In the Large Solar Scenario, California is allowed to export up to 1,500 MW of power during a given hour. This is consistent with the maximum export levels to the Pacific Northwest that are seen in the historical record (although it should be noted that California was importing larger quantities of energy from the Southwest during hours in which it was exporting to the Northwest).

There is considerable uncertainty about the appetite for exports of surplus power from California and the ability of the western grid to accommodate such exports. Moreover, this assumption requires a reversal of the longstanding historical pattern of large imports to California. Indeed, while the West-of-River transmission path connecting California to the Desert Southwest has an East-to-West rating of 10,600 MW, it does not have a formal West-to-East rating. It is therefore unknown at this time what level of exports from California the western grid can support.

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[42] Energy & Environmental Economics, "WECC EDT Phase 2 EIM Benefits Analysis & Results," October 2011, Prepared for WECC, <http://www.wecc.biz/committees/EDT/EDT%20Results/E3_EIM_Benefits_Study-Phase_2_Report_RevisedOct2011_CLEAN2%5B1%5D.pdf>

[43] Milligan, et al, NREL, "Examination of Potential Benefits of an EIM Imbalance Market in the Western Interconnection," prepared for PUCEIM group. <http://www.nrel.gov/docs/fy13osti/57115.pdf>

[44] Energy & Environmental Economics, "PacifiCorp-ISO Energy Imbalance Market Benefits", Prepared for CAISO & PacifiCorp, March 2013, <http://www.caiso.com/Documents/PacifiCorp-ISOEnergyImbalanceMarketBenefits.pdf>

Nevertheless, an analysis of load growth projections, resource retirements, and RPS policies in neighboring states suggested that by 2030, it may be possible to export up to 6,500 MW of power to the rest of the West. For example, load growth and coal retirements in the Pacific Northwest may already result in an erosion of that region's historical quantity of surplus hydro generation, despite increased wind generation that is required to meet RPS requirements in Washington and Oregon. This may provide an opportunity for exports from California to displace gas generation in the Northwest at the margin. Likewise, load growth in the Southwest is likely to be met in part with gas generation, although the potential prevalence of solar in the Southwest, combined with must-run coal generation, makes the demand for California exports more questionable.

The Enhanced Regional Coordination solution case allows exports to neighboring regions to absorb up to 5,000 MW of additional overgeneration experienced in the 50% RPS Large Solar case; when combined with the 1,500 MW of exports allowed in the Large Solar Scenario, a total of 6,500 MW of exports are allowed. This is shown for the example April day in Figure 26. Enhanced regional coordination decreases both the magnitude and the frequency of overgeneration events compared to the 50% RPS Large Solar Scenario. With enhanced regional coordination, total overgeneration is reduced from 9% (50% RPS Large Solar) to 3% of the total renewable energy and overgeneration must be mitigated with resource curtailment in 12% of all hours.

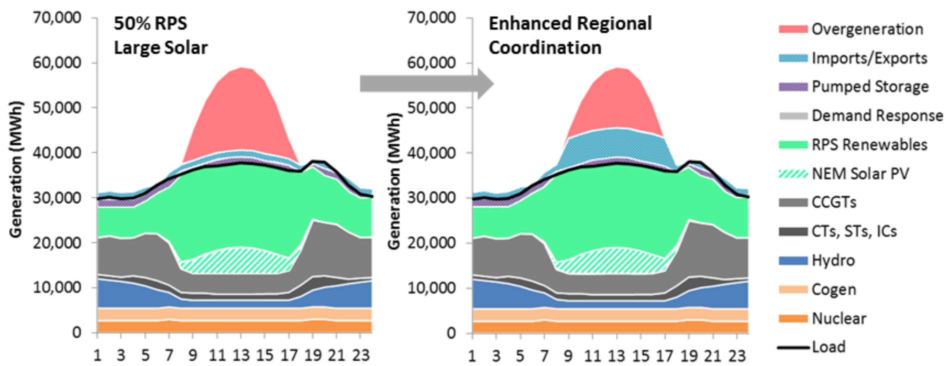

Figure 26: Generation mix on an April day for the 50% RPS Large Solar Scenario without and with the Enhanced Regional Coordination solution

4.2 Solution Category B: Conventional Demand Response

Curtailable load and other conventional demand response programs that result in reduced load during peak periods can help to provide flexibility by reducing the magnitude and frequency of extreme ramping events. If properly managed, the ramping capability of conventional demand response programs may also help with overgeneration by giving the system operator more latitude to reduce generation from conventional resources during times of high renewable production. For the purposes of this analysis, “conventional” demand response includes only load curtailment (for simplicity, modeled with no “rebound effect”); load shifting programs that provide additional downward flexibility by absorbing excess renewable generation are investigated in the Advanced Demand Response case (Section 4.3).

New conventional demand response is modeled as an additional resource that is scheduled in the day-ahead and hour-ahead markets at zero cost with a maximum capacity of 5,000 MW and a daily energy limit of 20,000 MWh. While conventional demand response in all other cases is modeled with a strike price of $137.50/MWh (consistent with CAISO modeling of demand response in its renewable integration studies), it is modeled here with a $0 strike price in order to find the "upper bound" on the flexibility impacts of curtailable loads. The impact of this 5,000 MW of new conventional demand response is shown for the example April day in Figure 27. On this day, the demand response contributes to meeting the ramping needs as the sun rises and as the renewable generation falls off at sunset.

Despite its energy and ramping contributions, conventional demand response does not significantly impact daytime overgeneration in the 50% RPS Large Solar case. Expected overgeneration remains at 9% of total renewable energy, largely unchanged from the Large Solar Scenario. This occurs because conventional generation has already been reduced to the minimum levels required for reliability in the Large Solar Case. While conventional demand response may help to reduce costs and GHG emissions by displacing gas-fired generation during extreme ramping events, it does little to help avoid overgeneration.

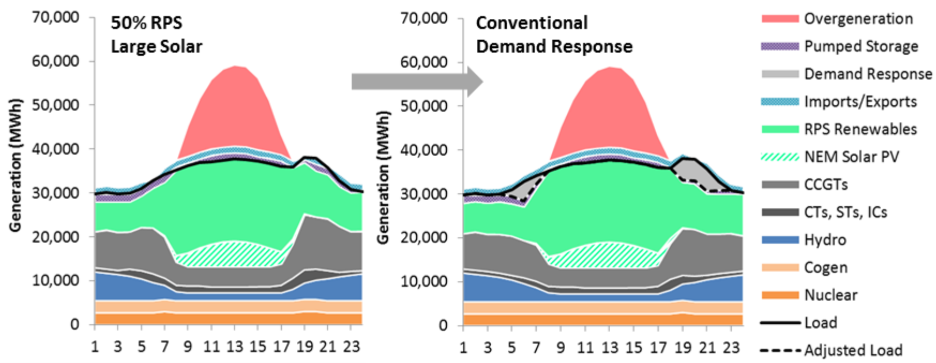

Figure 27: Generation mix on an April day for the 50% RPS Large Solar Scenario without and with the Conventional Demand Response solution

4.3 Solution Category C: Advanced Demand Response/ Flexible Loads

Unlike conventional demand response programs, advanced demand response programs that provide downward flexibility directly contribute to mitigating the overgeneration problem by absorbing energy during times of surplus. The Advanced Demand Response solution case models the effect of 5,000 MW of flexible loads. This flexible load is modeled in REFLEX as a load modifier that is scheduled in the day-ahead and hour-ahead markets. The load modifier can increase and decrease the load by up to 5,000 MW flexibly throughout the day, but the net energy impact over the course of the day is constrained to zero. This can be accomplished in a number of ways, e.g., by shifting energy end uses from one period of the day to the other with time-of-use (TOU) pricing or other rate design options, through other program designs such as controlled charging of electric vehicles, or through thermal energy storage (preheating or precooling).

Advanced Demand Response is shown to provide both the ramping contributions of conventional demand response and the downward flexibility benefits of the Enhanced Regional Coordination case (see Figure 28). This reduces the overgeneration to 4% of total renewable energy. Because overgeneration is driven by the need for downward flexibility, and both the Advanced Demand Response and Enhanced Regional Coordination cases provide 5,000 MW of downward flexibility, the overgeneration statistics are similar for the two cases.

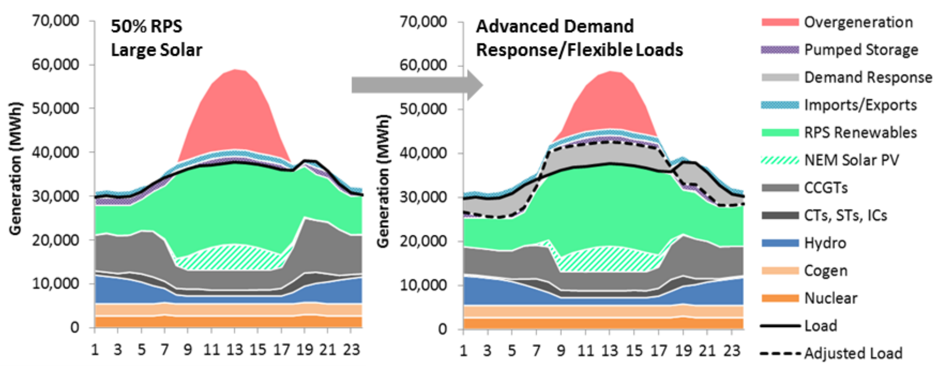

Figure 28. Generation mix on an April day for the 50% RPS Large Solar Scenario without and with the Advanced Demand Response solution

4.4 Solution Category D: Energy Storage

Similar to the Advanced Demand Response solution described above, energy storage can contribute to mitigating flexibility problems by providing both upward and downward flexibility. Because overgeneration is identified as the most critical integration challenge, energy storage is modeled as a diurnal energy shifting technology, similar to the Advanced Demand Response solution, but also incorporating round-trip losses.[45] The energy storage dispatch does not account for additional benefits associated with providing ancillary services. Round-trip losses reflect an assumed average energy storage efficiency of 80% (i.e. new pumped hydro and/or a mix of battery storage technologies). These losses are experienced as reduced delivery of energy back to the grid, resulting in higher natural gas generation but having no impact on the ability to mitigate overgeneration. The energy storage modeled with this approach is incremental to California's existing pumped storage capabilities, and can absorb up to 5,000 MW of excess generation. This requires a total energy storage capacity of approximately 50,000 MWh, or enough energy to discharge at 4,000 MW for 11 hours while accounting for losses.

Figure 29 shows the energy storage dispatch for the example April day. The Energy Storage solution has the same effect on overgeneration as the Advanced Demand Response solution, reducing overgeneration from 9% to 4% of total renewable energy production.

[45] Energy storage charging and discharging schedules were derived from the Advanced Demand Response simulation.

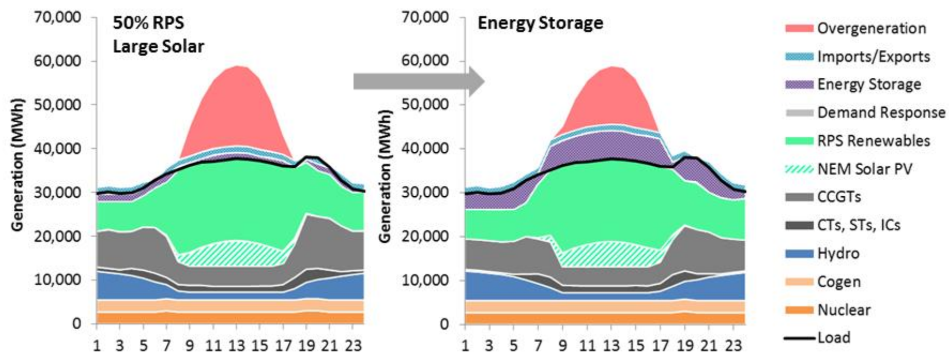

Figure 29: Generation mix on an April day for the 50% RPS Large Solar Scenario without and with the Energy Storage solution

4.5 Solution Category E: Renewable Portfolio Diversity

The effectiveness of each of the first four categories of solutions is driven by the ability to absorb daytime overgeneration resulting from the solar build-out in the 50% RPS Large Solar case. One alternative to absorbing the solar-driven overgeneration is to develop a more diverse portfolio of renewables to meet the 50% RPS that avoids or reduces the daytime overgeneration problem.

The Diverse Portfolio illuminates the flexibility benefits associated with renewable portfolio diversity, and allows those benefits to be compared to the benefits of implementing the various flexibility solutions with the 50% RPS Large Solar portfolio. While the Diverse Portfolio has higher RPS generation costs, this study investigates how this higher cost compares to the benefit from reducing flexibility violations.

As is shown on the April example day (Figure 30), the diverse renewable portfolio generates more renewable energy at night relative to the 50% RPS Large Solar case and reduces daytime overgeneration. The flexibility benefits of the Diverse Scenario are similar to those of procuring 5,000 MW of energy storage or advanced demand response. Overgeneration is reduced to 4% of total renewable energy, occurring in 15% of hours for the 50% RPS Diverse Portfolio case.

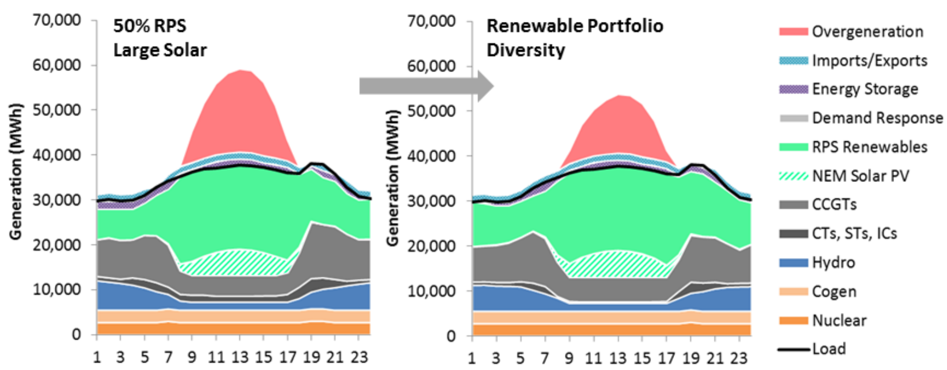

Figure 30. Generation mix on an April day for the 50% RPS Large Solar case compared to the 50% RPS Diverse Renewable Portfolio case

Overgeneration experienced with the Diverse Portfolio follows the same seasonal and diurnal trends as the 50% RPS Large Solar case, with most violations occurring during daytime hours in low load conditions during the spring and to a lesser extent in the fall (See Figure 31). However, the overall level of overgeneration is substantially reduced.

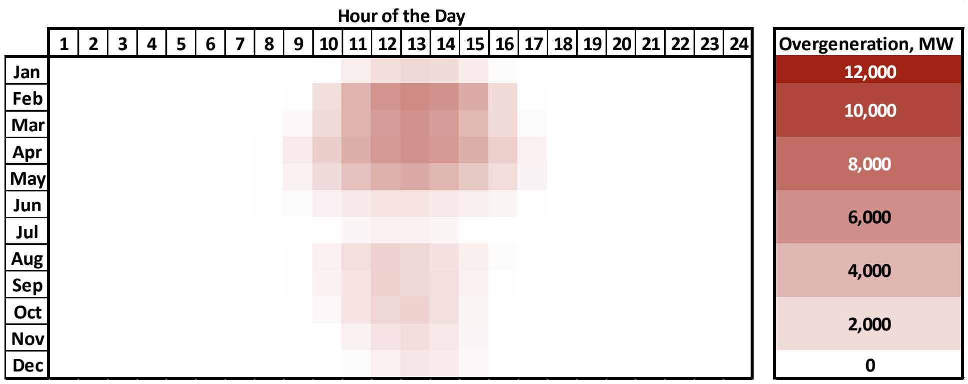

Figure 31: Overgeneration in the Study Area that must be mitigated by month-hour in the 2030 50% RPS Diverse Renewable Portfolio case

4.6 Flexibility Solutions Discussion

4.6.1 MITIGATION OF OVERGENERATION IS NEEDED

None of the solutions modeled in this analysis completely solve the renewable integration and overgeneration challenges. While the determination of an "optimal" resource portfolio or set of renewable integration solutions is beyond the scope of this study, the directional results of this analysis indicate that a combination of multiple solutions is likely to be necessary to substantially mitigate the overgeneration associated with a 50% RPS.

The flexibility modeling analysis suggests that the most valuable integration solutions at 50% RPS are those that can reduce solar-driven overgeneration during daytime hours when the system experiences low load conditions. This is true both for the Large Solar Scenario and the Diverse Scenario. The conclusions regarding system flexibility and the effectiveness of each solution category therefore center on the reduction of system-wide overgeneration.

Downward flexibility solutions, including increased exports, flexible loads, and diurnal energy storage help to mitigate this overgeneration. Alternatively, procurement of a more diverse portfolio of renewable resources spreads the renewable generation over more hours of the day and reduces the daytime overgeneration compared to the Large Solar portfolio.

The remaining overgeneration that must be mitigated in each solution case is shown in Table 28 as a percentage of the total available renewable energy on the system. If renewable curtailment is used to mitigate the overgeneration, this percentage represents the share of the renewable output that must be curtailed and therefore replaced with additional build of renewable resources in order to meet the 50% RPS. With none of the integration solutions implemented, overgeneration is approximately equal to 9% of the available renewable energy. Integration solutions that provide only upward flexibility, like conventional demand response, have a negligible effect on this overgeneration. However, integration solutions that provide downward flexibility reduce the overgeneration to between 3 and 4% of the available renewable energy. Similarly, procuring a more diverse portfolio of renewable resources results in overgeneration of approximately 4% of the available renewable energy.

Table 28: Overgeneration statistics for 50% RPS Large Solar Scenario and Solution Cases[46]

Overgeneration Statistics	50% RPS Large Solar	Enhanced Regional Coordination	Conventional Demand Response	Advanced DR or Energy Storage	Diverse Portfolio
Total Overgeneration					
GWh/yr	12,000	4,700	12,000	5,000	5,400
% of available RPS energy	8.9%	3.4%	8.8%	3.7%	4.0%
Overgeneration					
Hours/yr	2,000	1,000	2,000	1,200	1,300
Percent of hours	23%	12%	23%	14%	15%
Extreme Overgeneration Events					
99th Percentile (MW)	15,000	9,900	15,000	9,900	10,000
Maximum Observed (MW)	25,000	20,000	25,000	20,000	19,000

Overgeneration duration curves for the solution cases are shown in Figure 32. The chart shows that the decrease in overgeneration is fairly constant across solutions that provide downward flexibility. In these solution cases, up to 5,000 MW of overgeneration can be absorbed in nearly all hours[47]. To a first-order approximation, the solutions that provide downward flexibility shift the overgeneration curve downward by the "nameplate capacity" of the solution. Each of the solution cases, with the exception of the diverse scenario, is designed to provide 5,000 MW of this downward flexibility, so the overgeneration curve is shifted down by approximately 5,000 MW.

[46] Results are rounded to two significant figures.
[47] The advanced demand response and energy storage solutions have energy constraints that may limit the downward flexibility in some hours.

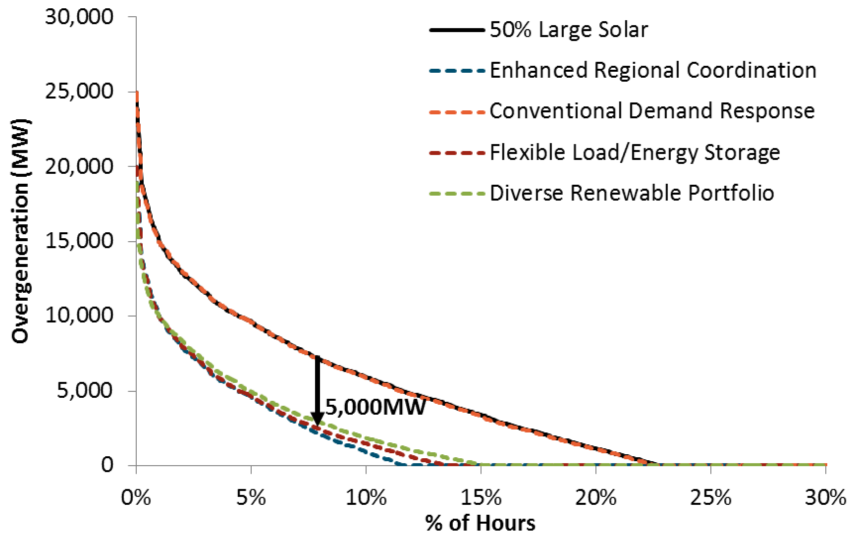

Figure 32: The effect of each solution category on overgeneration for the 50% RPS Large Solar Scenario

Preliminary analysis suggests that the effects of the various solutions, if implemented together, are additive. Figure 33 shows the effects of incremental flexibility solutions on the overgeneration curve. As more downwardly-flexible solutions are implemented, overgeneration decreases. Adding 15,000 MW of downward flexibility solutions to the Large Solar Scenario results in roughly the same quantity of overgeneration as in the 33% RPS Scenario.

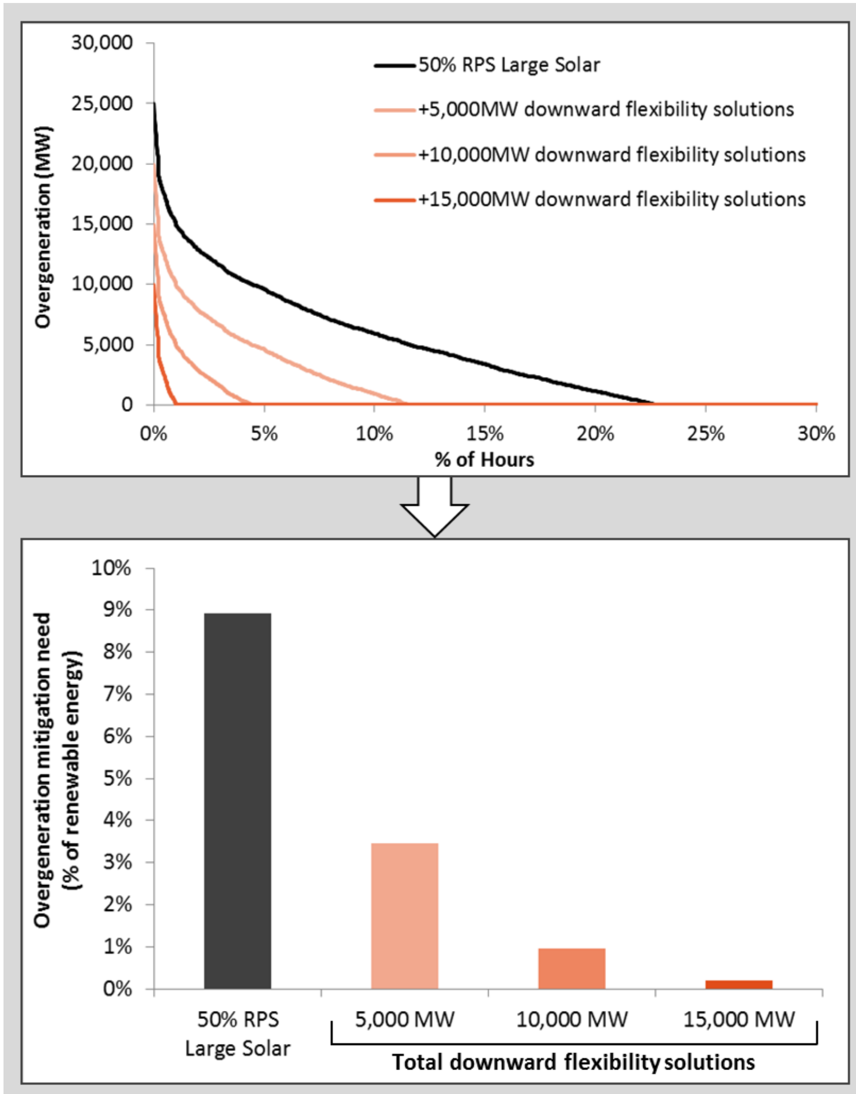

Figure 33: Adding 15,000 MW of downward flexibility solutions to the Large Solar Scenario results in roughly the same quantity of overgeneration as in the 33% RPS Scenario

4.6.2 IMPLEMENTATION ISSUES AND POTENTIAL CHALLENGES

This study shows that integrating high levels of renewables onto California's grid will likely require innovation, new technologies and/or new policies to provide system flexibility and help manage overgeneration. While technically feasible, none of the solutions evaluated in this chapter have been tested at scale, and each faces implementation challenges of its own. Furthermore, the magnitude of the overgeneration challenge under a 50% RPS means that reliance on a single renewable integration strategy may not be feasible or cost-effective; a combination of solutions is likely to be needed.

+ **Enhanced regional coordination** could have a number of benefits in addition to reducing the renewable integration burden, including improving the efficiency of power system operations across the Western Interconnection as well as enhancing the reliability and security of the western grid. While many forms of regional coordination are currently being explored, not all western market participants believe that the benefits of more coordination outweigh the costs and risks, and the ultimate trajectory of regional coordination efforts is unclear at this time.
+ **Advanced demand response and flexible loads,** allowing both upward and downward changes to energy demand, is a promising resource which has not yet been tested at scale for renewable integration purposes. Historically, DR events have been limited to a few curtailment events during the most extreme peak hours. The technical potential for flexible loads that can move both up and down is unknown. Strategies for enrolling flexible load to serve renewable integration needs are being developed in utility Emerging Technology DR programs. Fast responding load-based resources have moved beyond the pilot and demonstration stage and are in commercial operation in some places. However,

significant challenges remain including regulatory issues regarding retail load participation in wholesale markets.

- **Energy storage** provides a direct solution to the overgeneration problem. There are many kinds of energy storage—batteries, fly-wheels, compressed air energy storage, pumped hydro, etc.—each with different costs, round-trip efficiencies and performance characteristics. This analysis indicates that diurnal energy storage is likely to be the most useful in addressing the overgeneration challenges observed at high renewable penetrations, requiring relatively long duration energy storage. Pumped hydro, while a mature technology that can achieve long-term energy storage without significant losses, faces environmental citing and permitting challenges. Most other energy storage technologies remain high cost, although R&D is underway to reduce costs and improve performance.
- **Diversity in the renewable resource portfolio** is beneficial on both a geographic basis and a technology basis. Procuring a more diverse resource portfolio may require new mechanisms to value diversity and integration costs in resource procurement choices. Furthermore, achieving greater renewable resource diversity may be challenging if it requires developing, siting and permitting out-of-state resources and transmission.

5 Cost and Environmental Impacts

5.1 Overview

5.1.1 EVALUATION METRICS

Five key cost and environmental metrics are used to evaluate each 2030 scenario evaluated in this report:

+ **Total utility cost (or revenue requirement)** includes all the costs that a utility incurs to provide reliable service to its customers. For the purpose of this study, costs are grouped into six categories: transmission, distribution, conventional generation, renewable generation, greenhouse gas costs, and miscellaneous/other costs. With the exception of miscellaneous/other costs, the choice of an RPS policy and the strategy used to meet that goal affects costs in each category.
+ **Average system rate** is the average price paid by a utility's customers to serve a unit of load, and is calculated by dividing the Study Area's revenue requirement by its total retail sales.
+ **Capital investment** includes the total capital costs of new conventional generation, renewable generation, transmission lines and distribution infrastructure needed to meet the RPS target and serve load reliably.

+ **Greenhouse gas emissions** are the total quantity of greenhouse gases emitted by the electric sector on an annual basis associated with serving the Study Area load. This includes emissions from natural gas and cogeneration facilities in the state of California as calculated in REFLEX, as well as emissions attributed to power imported from other jurisdictions in the West.
+ **Implied cost of carbon abatement** is a measure of the cost of the RPS policy as a strategy for reducing greenhouse gas emissions. It is calculated by dividing the incremental cost of a portfolio relative to the 33% RPS Scenario by the incremental greenhouse gas savings achieved by the alternative scenario relative to the 33% RPS scenario.

This study does not monetize other benefits of a higher RPS such as reductions in criteria pollutants or other environmental benefits, nor does it attempt to quantify the costs or benefits of an RPS that are not directly applicable utility costs, such as macroeconomic impacts or "lifecycle" (i.e. manufacturing or waste management) environmental impacts.

The Study Area's revenue requirement in 2030 is the sum of: (1) common costs, which includes revenue requirement categories that do not change across RPS scenarios; and (2) scenario-specific costs that change across RPS scenarios. To support this study, the utilities provided 2012 revenue requirement estimates for common cost categories and real annual escalation rate assumptions to project these costs from 2012 to 2030. Scenario-specific, RPS-related costs are calculated by using the results of technical modeling, including E3's REFLEX, RECAP, Capital Cost and Distribution System Analysis models.[48] Figure 34 below

[48] See Appendix D for more detail on how each revenue requirement category is calculated.

depicts the relationship between the different components of this analysis, the revenue requirement cost categories and how they are combined to generate an estimate of total cost (revenue requirement) in 2030.

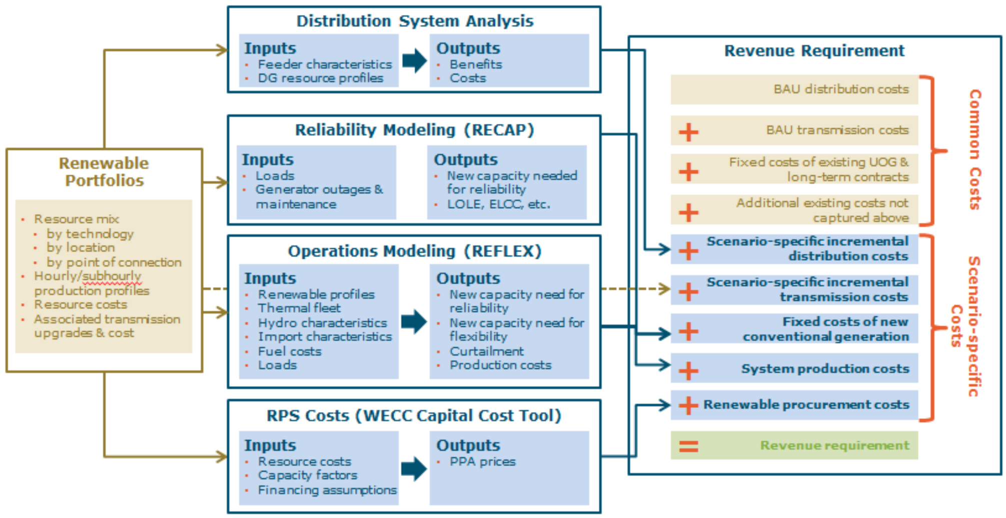

Figure 34: Revenue requirement framework

5.1.2 RENEWABLE OVERBUILD COST

At high penetrations of renewables, the frequency of overgeneration results in increased renewable overbuild costs. This is because, in the absence of other renewable integration solutions, overgeneration is assumed to be mitigated with renewable curtailment to maintain system reliability. This results in a need to overbuild renewable generation, above what would otherwise be needed, to ensure that the scenario meets the given RPS target even after taking curtailment into account.

E3 estimates the renewable overbuild cost—the cost of procuring renewables to replace renewable production that is curtailed due to overgeneration—for each RPS scenario using the following steps:

1. Outputs from REFLEX are used to calculate the marginal overgeneration rate of each renewable technology (see Section 3.4.2).

2. The marginal overgeneration factors are used to calculate the amount of additional energy needed from each renewable technology to achieve the target RPS level after accounting for curtailed energy. For each scenario, the composition of the renewable overbuild portfolio is assumed to be the same mix of renewable technologies as the scenario-specific portfolio of renewable resources (incremental to a 33% RPS).

3. The renewable overbuild cost is calculated by multiplying the additional energy required due to curtailment by the renewable resource cost, accounting for the marginal overgeneration impacts of additional renewable resources.

This approach may underestimate the cost of the renewable overbuild to the extent that it does not account for the iterative nature of additional renewable generation further contributing to the overgeneration challenge. This study assumes that developers are paid the full cost of the power purchase agreement, whether the energy is delivered to customers or curtailed due to overgeneration. This approach is consistent with the study's assumption that all renewable procurement is assumed to occur at cost. The study does not address implementation issues associated with future renewable curtailment under a higher RPS.

5.2 Results

5.2.1 RETAIL RATES AND REVENUE REQUIREMENTS

Higher RPS targets result in costs and benefits to ratepayers, impacting the cost of providing electric service. The primary drivers of *increased* costs include: (1) increased procurement costs for renewable generation; (2) increased investment in transmission infrastructure to deliver utility-scale renewables to load; (3) increased investment in distribution infrastructure to provide reliable service under high penetrations of distributed resources, and (4) increased renewable integration costs, primarily in the form of renewable generation overbuild costs to ensure that each scenario achieves the target RPS level even after accounting for curtailment.

Higher penetrations of renewables also create benefits that *decrease* utility costs, including: (1) displacing fossil generation and avoiding energy market purchases or fuel costs; (2) reducing the need to rely on fossil plants for resource adequacy and avoiding capacity costs; (3) deferring transmission and distribution upgrades (in the case of DG); and (4) reducing greenhouse gas emissions and the compliance costs associated with them. Figure 35 and Table 29 show the resulting total cost in the six functional revenue requirement categories for each of the scenarios, and Figure 36 and Table 30 show the system average retail rates.

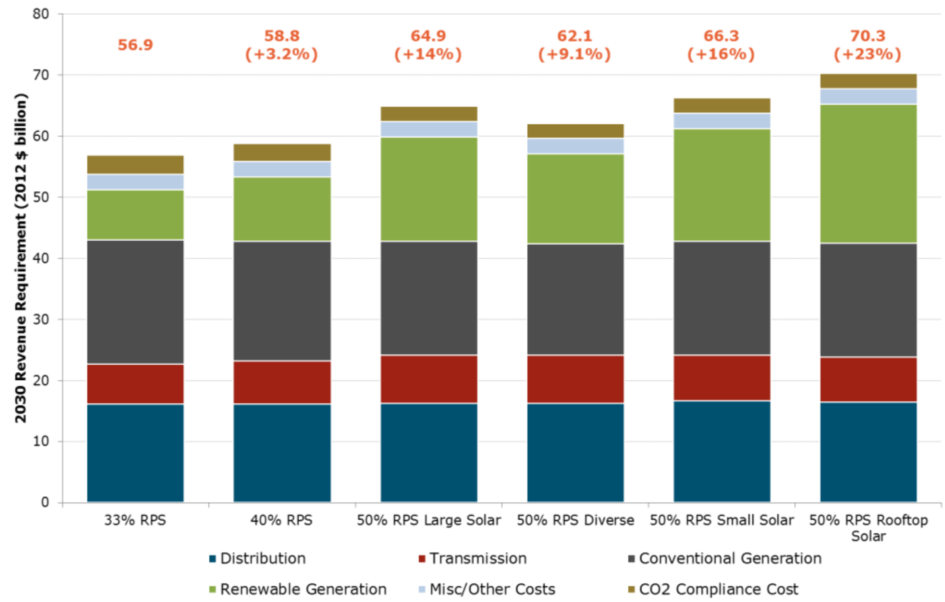

Figure 35: 2030 revenue requirement (2012 $ billion) for each scenario (Percentage change is relative to 33% RPS)

Table 29: 2030 revenue requirement (2012 $ billion) for each scenario (Percentage change is relative to 33% RPS)

Revenue Requirement Category	33% RPS	40% RPS	50% RPS Large Solar	50% RPS Diverse	50% RPS Small Solar	50% RPS Rooftop Solar
CO_2 Compliance Cost	3.2	2.9	2.5	2.4	2.5	2.5
Conventional Generation	20.3	19.5	18.7	18.1	18.7	18.6
Renewable Generation	8.2	10.6	17.1	14.8	18.5	22.8
Transmission	6.5	7.1	7.8	7.9	7.4	7.3
Distribution	16.2	16.2	16.3	16.3	16.7	16.5
Misc/Other Costs	2.5	2.5	2.5	2.5	2.5	2.5
Total	**56.9**	**58.8**	**64.9**	**62.1**	**66.3**	**70.3**
Percentage Change	n/a	3.2%	14.0%	9.1%	16.4%	23.4%

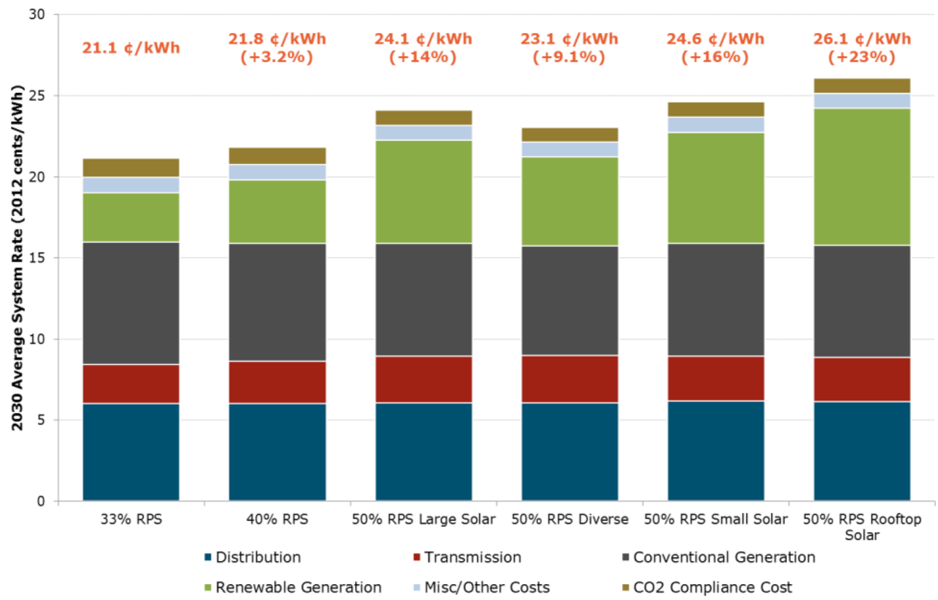

Figure 36: 2030 average system retail rate (2012 cents/kWh) for each scenario (Percentage change is relative to 33% RPS)

Table 30: 2030 average system retail rate (2012 cents/kWh) for each scenario (Percentage change is relative to 33% RPS)

Revenue Requirement Category	33% RPS	40% RPS	50% RPS Large Solar	50% RPS Diverse	50% RPS Small Solar	50% RPS Rooftop Solar
CO_2 Compliance Cost	1.2	1.1	0.9	0.9	0.9	0.9
Conventional Generation	7.6	7.3	6.9	6.7	6.9	6.9
Renewable Generation	3.1	3.9	6.4	5.5	6.9	8.5
Transmission	2.4	2.6	2.9	2.9	2.8	2.7
Distribution	6.0	6.0	6.0	6.0	6.2	6.1
Misc/Other Costs	0.9	0.9	0.9	0.9	0.9	0.9
Total	**21.1**	**21.8**	**24.1**	**23.1**	**24.6**	**26.1**
Percentage Change	n/a	3.2%	14.0%	9.1%	16.4%	23.4%

Figure 36 illustrates a number of key study results:

+ The 50% RPS scenarios result in an increase in retail rates between 1.9 and 4.9 cents per kWh (or 9% and 23%), depending on the procurement strategy chosen to move from 33% to 50%.
+ The effect of moving from 33% to 50% is nonlinear. The increase in costs between 33% and 40% is 0.7 cents per kWh, whereas the cost increase between 40% and 50% is 2.3 cents per kWh—more than three times the difference.
+ In spite of the fact that the Large Solar Scenario relies heavily on the resource with the lowest levelized cost in 2030, the retail rates of the Diverse Scenario are the lowest of any of the 50% RPS scenarios. This is because overgeneration in the Large Solar Scenario is much higher than the Diverse Scenario.
+ The rate impact of the Small Solar Scenario is fairly close to that of the Large Solar Scenario and the Rooftop Solar Scenario is the highest cost option for meeting the 50% RPS.
+ The *renewable overbuild cost*, the cost of procuring renewables in excess of the portfolio to 'replace' renewable overgeneration, results in cost increases for ratepayers even when the costs of renewable generation are low compared to traditional fossil resources. The need to overbuild the renewable portfolio to meet a high RPS target helps explain both the nonlinearity of the cost increase between 33% and 50% RPS and the relative costs of the different 50% portfolios.
+ These results show that some of the renewable overbuild cost increases can be mitigated by pursuing diversity in resource procurement: a diverse set of resources can reduce the frequency of overgeneration

relative to a portfolio that relies heavily on a single technology, leading to less need to overbuild the renewable portfolio to meet a RPS target. Other renewable integration solutions would also help reduce these costs, as described in Section 5.4.5 below.

5.2.2 CAPITAL INVESTMENT

Table 31 shows the estimated amount of capital investment required from 2013 – 2030 to construct the infrastructure in the RPS scenarios. Total capital investment includes new renewable and conventional generating resources, and new transmission and distribution infrastructure. Maintaining a 33% RPS in 2030 requires $24 billion of capital, while achieving a 50% RPS requires $89 - $128 billion, an increase of $64 to $104 billion. Capital investment in new renewable generation reflects overbuild.

Table 31: Cumulative capital investment through 2030, incremental to 33% RPS in 2020, by scenario (2012 $ billion)

	33% RPS	40% RPS	50% RPS Large Solar	50% RPS Diverse	50% RPS Small solar	50% RPS Rooftop Solar
New Renewable Generation	9.2	29.5	65.2	61.0	72.0	105.3
New Conventional Generation	11.7	11.2	11.2	11.2	11.2	11.2
New Transmission	2.8	6.6	12.0	15.2	9.3	8.5
New Distribution	0.6	0.9	1.4	1.4	4.2	3.0
Total Capital Investment	**24.4**	**48.1**	**89.8**	**88.7**	**96.6**	**128.0**

5.2.3 GREENHOUSE GAS EMISSIONS

Figure 37 shows the total system greenhouse gas (GHG) emissions resulting from the portfolio of resources used to serve loads in each of the scenarios. The Study Area's electric sector greenhouse gas emissions include emissions from natural gas-fired plants in the Study Area used to serve system load and emissions from imports, and exclude emissions from exports. The emissions rate for imports is 0.428 tons/MWh, which is ARB's current deemed emissions rate for unspecified imports and equivalent to a natural gas plant with a 8,066 Btu/kWh heat rate; however, imports have only a minor effect on California GHG emissions in 2030.

- By 2030, the expected emissions of the Study Area under a 33% RPS are estimated to be 64 million metric tons.
- Increasing the RPS to 40% reduces GHG emissions by 6 million metric tons relative to a 33% RPS.
- The transition to a 50% RPS would result in additional carbon savings of between 14 and 15 million metric tons relative to a 33% RPS.
- The reduction in emissions as the RPS policy increases is non-linear due to the fact that as more renewable power is added: (1) the *marginal* fossil generator that is displaced is increasingly efficient (i.e., low-carbon); and (2) the remaining fossil generation that is committed and dispatched to provide reserves and energy is more frequently operating at a lower dispatch point, which results in a higher *average* heat rate (the average heat rate of thermal generating resources increases from 7,650 Btu/kWh in the 33% RPS Scenario to 7,880 Btu/kWh in the 50% RPS Large Solar Scenario). The combination of these effects results in fewer CO_2 emissions saved per MWh of renewables under higher RPS.

+ The emissions from each of the 50% RPS scenarios are fairly comparable. The Diverse Scenario has slightly lower emissions due to combined cycle gas turbines (CCGTs) being utilized more frequently than combustion turbines (CTs) in the other 50% RPS scenarios.

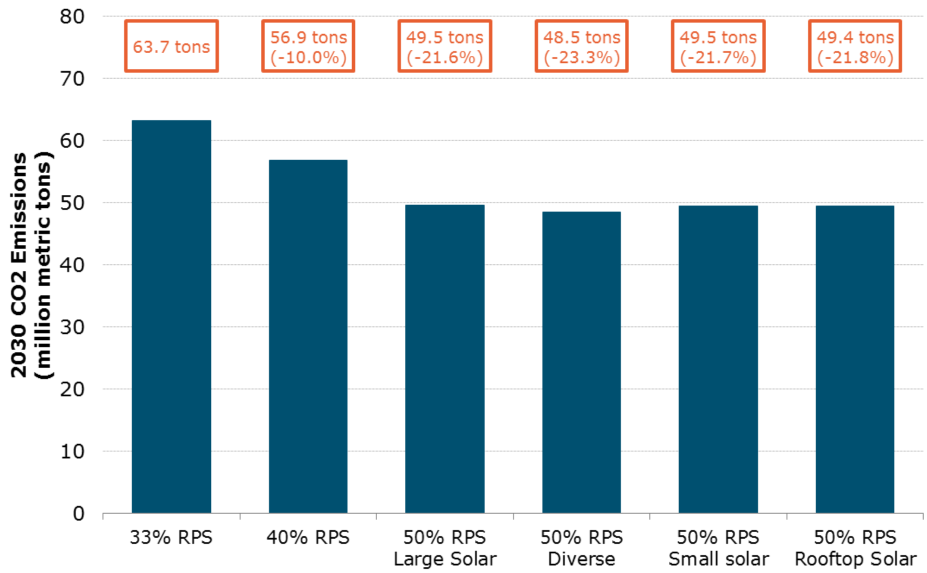

Figure 37. 2030 electric system Study Area greenhouse gas emissions

5.2.4 IMPLIED COST OF CARBON ABATEMENT

Figure 38 shows the cost of carbon abatement for each portfolio relative to the 33% RPS portfolio. This formulation implicitly attributes all of the cost of meeting a higher RPS to GHG emissions reductions. It therefore ignores other potential societal benefits of increased renewable penetration such as reduced emissions of "criteria" pollutants such as NO_x and SO_x. Several points are worth noting:

+ Compared to the assumed 2030 carbon price in this analysis ($50/ton), which is based on a projection of California's current cap-and-trade regulations, the implied cost of carbon abatement resulting from increased investment in renewable resources is high. This implies that a substantial premium must be paid for renewable generation above the expected market price of CO_2.

+ The implied cost of abatement in the 50% RPS Large Solar Scenario ($637/ton) is higher than in the 40% RPS case ($340/ton). This increase reflects the fact that as more renewable power is added to the system, the total cost increases more quickly than the CO_2 savings.

+ Among the 50% portfolios, the Diverse Scenario has the lowest cost of abatement ($403/ton) because, of the 50% RPS scenarios, is has the lowest total cost.

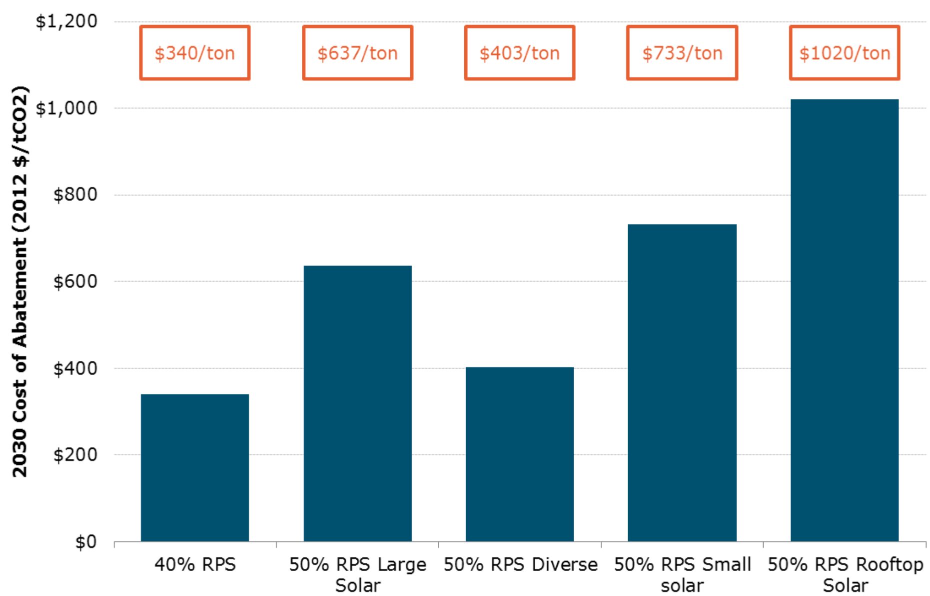

Figure 38: Implied cost of carbon abatement in 2030 for each Scenario relative to the 33% RPS Scenario

5.3 Solution Case Cost Ranges

A detailed cost-benefit analysis of these renewable integration solutions is beyond the scope of this study. In lieu of such an analysis, we provide cost and rate results under an illustrative range of high and low cost assumptions for the implementation of 5,000 MW of each of the solutions that are shown to have a potential renewable integration benefit. Even though the study assumes significant quantities of each solution (5,000 MW) are implemented, these cases are not sufficient to fully eliminate the overgeneration challenge. The study does not include an analysis of the optimal level of integration solutions, nor does it assess the feasibility of procuring or implementing 5,000 MW of these renewable integration solutions by 2030.

Table 32 shows the cost ranges that are assumed for this section. These assumptions represent, at a high level, a range of potential costs for each category. In reality, each category would likely be made up of a number of individual measures or projects, each of which would have unique costs and benefits. For example, the energy storage solution case could include a mixture of pumped storage, batteries, and other storage technologies. Furthermore, implementation of these integration solutions would require advance planning and in many cases, long-lead times, and could face regulatory and/or permitting challenges. Nevertheless, this section provides an indication of the extent to which cost reductions could be achieved through implementation of solutions in each of these categories.

- For energy storage, low and high costs are based on published estimates of the cost of pumped storage and flow battery technologies, respectively.

- For flexible load, the low cost range assumes that load shifting can occur at no incremental cost through rate design (e.g., time-of-use pricing) or programs with other ancillary benefits that offset any program costs. The high cost range incorporates capital cost assumptions for thermal energy storage devices (e.g. pre-cooling or pre-heating).

- For regional coordination, the low cost range assumes surplus California energy displaces natural gas generation in other regions, and that California receives the benefit of operating cost savings. The high cost range assumes that surplus California generation cannot easily displace fossil generation in other areas, such that California must compensate buyers in other areas for increased cycling and O&M costs.

Table 32: High and low cost estimates for solution categories modeled

Solution	Sensitivity	Basis	Cost Metric
Storage	Low	Pumped hydro cost ($2,230/kW; 30-yr lifetime); Black and Veatch *Cost and Performance Data for Power Generation Technologies*[49]	$375/kW-yr
	High	Battery cost ($4,300/kW; 15-yr lifetime); Black and Veatch *Cost and Performance Data for Power Generation Technologies*	$787/kW-yr
Flexible Load	Low	Load shift achieved through rate design at no incremental cost	$0/kW-yr
	High	Average TRC cost of thermal energy storage ($2,225/kW; 15-yr lifetime); E3 *Statewide Joint IOU Study of Permanent Load Shifting*[50]	$413/kW-yr
Regional Coordination	Low	Assume CA receives $50/MWh for exported power	-$50/MWh exported
	High	Assume CA pays $50/MWh to export incremental power	$50/MWh exported

Table 33 shows the cost impacts of implementing these solutions with the portfolio modeled under the Large Solar Scenario. The Large Solar Scenario with only the default renewable curtailment solution and the Diverse Scenario costs are shown for reference. The costs shown in the table include the benefits of

[49] Study available at: http://bv.com/docs/reports-studies/nrel-cost-report.pdf.
[50] Study available at: http://www.ethree.com/public_projects/sce1.php.

each solution, in the form of reduced overgeneration plus any fuel savings, O&M costs, emissions reductions and capacity savings that they provide, in addition to the low and high cost estimates shown in Table 32 above.

The table shows that the Enhanced Regional Coordination and Advanced DR solutions provide significant cost savings relative to the Large Solar Scenario without solutions, even under the high cost range.

- The Enhanced Regional Coordination solution reduces total cost by $2.6 – 3.4 billion. Total costs are similar to those of the Diverse Scenario. However, cost is not the most significant barrier for the Enhanced Regional Coordination solution. Rather, the challenge is institutional; there are significant barriers to achieving more coordinated operations among western market participants.
- The Advanced DR solution reduces total cost by $1.2 – 3.3 billion. Total costs are similar to those of the Diverse Scenario. For the Advanced DR solution, the initial challenge will be in characterizing the size and nature of the potential resource available, and then designing programs to achieve the benefits in a cost-effective manner.
- The high cost Energy Storage solution case results in cost impacts that fall above the Large Solar Scenario cost. It should be noted that this analysis does not include all the benefits that energy storage could provide; for example, no benefits are assumed for provision of regulation services or deferral of transmission and distribution investments. Low-cost pumped storage, on the other hand, reduces the total cost of achieving a 50% RPS under the Large Solar Scenario by $1.5 billion.

Table 33: Cost impacts of solution cases under low and high cost ranges (5,000 MW change)

		Solution Cases - Large Solar With:			
	50% RPS Large Solar	Energy Storage	Enhanced Regional Coordination	Advanced DR	50% RPS Diverse
2030 Revenue Requirement (2012 $ billion)					
Low Solution Cost	64.9	63.4	61.5	61.6	62.1
High Solution Cost		65.5	62.3	63.7	
2030 Average System Rate (2012 cents/kWh)					
Low Solution Cost	24.1	23.5	22.8	22.9	23.1
High Solution Cost		24.3	23.1	23.6	
Percentage Change in 2030 Average System Rate (relative to 33% RPS)					
Low Solution Cost	14.0%	11.4%	8.0%	8.2%	9.1%
High Solution Cost		15.0%	9.3%	11.8%	

5.4 System Average Rate Sensitivity Results

Estimating system average retail rates for a period two decades in the future involves a considerable amount of uncertainty, as many of the costs related to renewables—both direct and indirect—cannot be known with certainty. This study therefore evaluates the sensitivity of the retail rate impacts for each of the main 2030 Scenarios against several key input variables: (1) natural gas prices, (2) carbon prices, (3) renewable resource costs, and (4) renewable overbuild costs. For each of these assumptions, E3 developed high and low sensitivities that are intended to represent plausible ranges in order to provide a clear indication of the assumption's impacts on results.

5.4.1 NATURAL GAS PRICE SENSITIVITY

The price of natural gas is an important driver of the cost of scenarios: in all scenarios, natural gas combustion represents the largest or second-largest source of generation used to serve California's loads. At the same time, it is also one of the most uncertain; natural gas prices are notoriously difficult to forecast with any accuracy. Accordingly, this study attaches a wide range to the natural gas price sensitivity as illustrated in Table 34.

Table 34: Natural gas price sensitivities

Sensitivity	2030 Burnertip Natural Gas Price (2012 $/MMBtu)
Base Case	$6.06
High Gas Price	$10.00
Low Gas Price	$3.00

The effect of varying natural gas prices across this range is illustrated in Figure 39. A number of points are worth noting:

+ The sensitivity of retail rates to natural gas prices declines as the penetration of renewable resources grows, as the utilities' portfolios are less reliant on natural gas generation to serve loads.
+ While high gas prices increase the overall level of retail rates, the High Gas Price sensitivity reduces the net cost of moving to higher RPS: the rate impacts of 3.0 cents/kWh (Large Solar) and 1.9 cents/kWh (Diverse) in the Reference Case are reduced to 2.6 cents/kWh and 1.5 cents/kWh, respectively.

+ Conversely, the net cost of the RPS is higher in the Low Gas Price sensitivity: the rate impacts of 3.0 cents/kWh (Large Solar) and 1.9 cents/kWh (Diverse) in the Reference Case grow to 3.3 cents/kWh and 2.2 cents/kWh, respectively, even while average retail rates are lower than in the Base Case.

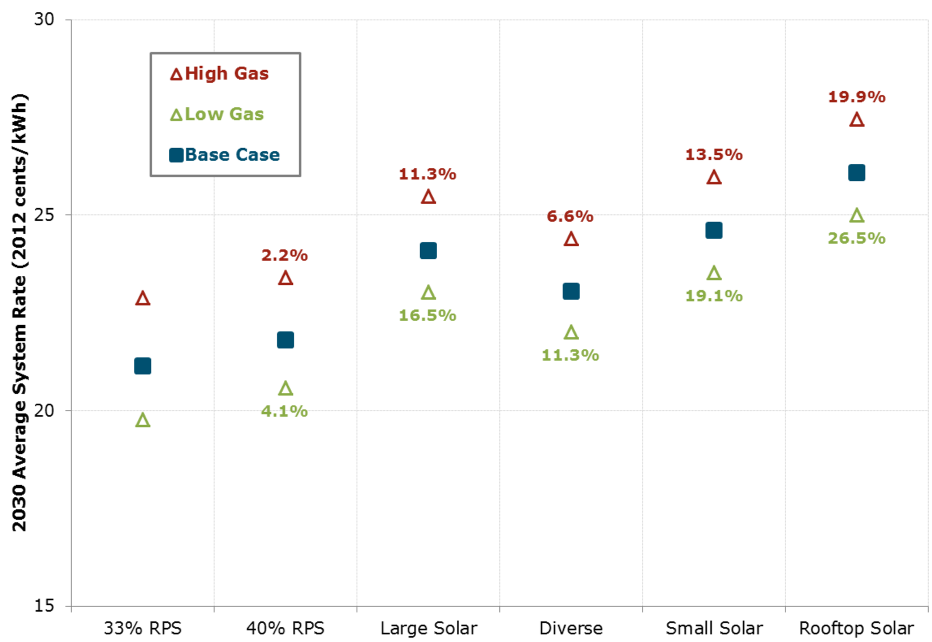

Figure 39: Sensitivity of retail rates (2012 cents/kWh) to natural gas prices (percentage change relative to 33% RPS Scenario applicable sensitivity)

5.4.2 CARBON PRICE SENSITIVITY

California's recent implementation of a cap-and-trade program resulted in the formal introduction of carbon pricing into the electric sector. Under current program design, however, the allowable range of carbon prices is large. E3 chose to examine the sensitivity of retail rates to carbon prices at the floor and ceiling under current cap-and-trade policy. Figure 40 illustrates the trajectory of CO_2 prices over 2013-2020 and Table 2 summarizes the range of prices used in this study.

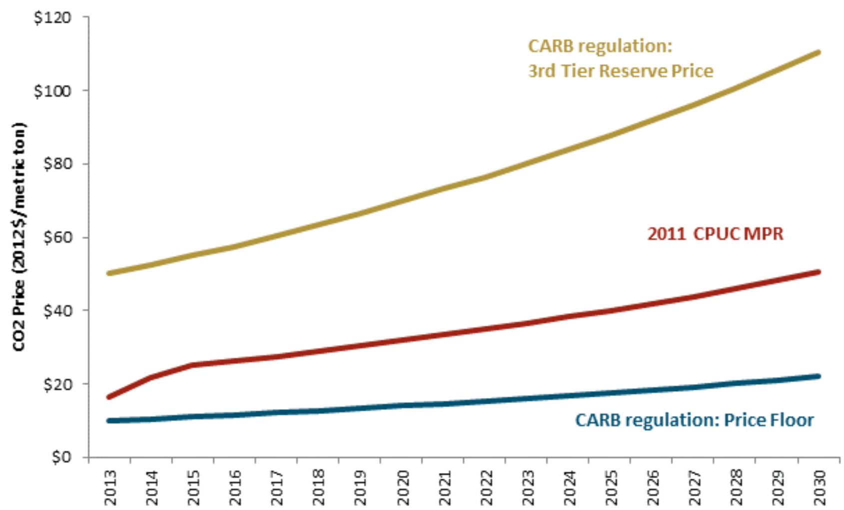

Figure 40: California CO_2 price assumptions between 2013 and 2030

Table 35: Carbon price sensitivities

Sensitivity	2030 Carbon Price ($/ton)
Base Case	$50.38
High CO_2 Price	$110.44
Low CO_2 Price	$22.09

Figure 41 summarizes the results of the carbon price sensitivities.

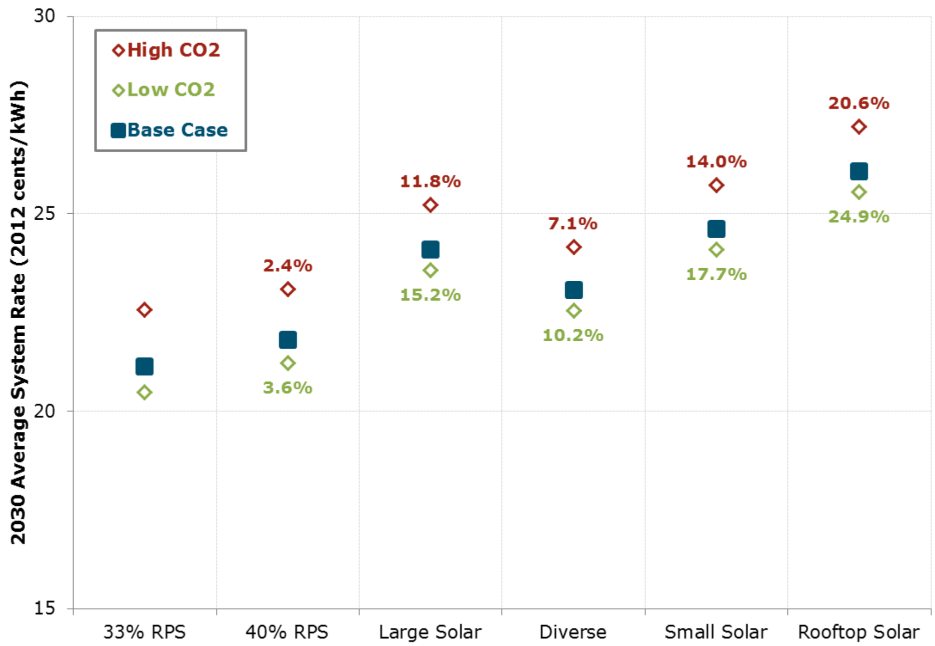

Figure 41: Sensitivity of retail rates to carbon prices (percentage change relative to 33% RPS Scenario applicable sensitivity)

5.4.3 RENEWABLE RESOURCE COST SENSITIVITY

The cost of renewable resources represents a third key uncertainty in the results of this study. With the growth of renewable industries both in California and around the world, the costs of nascent and emerging renewable technologies have changed dramatically in the past several years. Most notably, the costs of solar PV have persistently decreased as the industry has expanded in recent years. The costs of wind and solar thermal technologies have also declined, though to a lesser extent than solar PV.

Base case renewable costs reflect an assumption that the past trends in renewable cost changes will continue into the future at similar rates. This corresponds to real cost reductions between 2013 and 2030 of 30% and 10% for solar PV and wind, respectively.[51] E3 derived cost sensitivities for renewables by altering the trajectories of solar PV and wind costs in the future (other technologies were deemed sufficiently mature to justify the assumption that costs would remain stable over time even in sensitivity cases). The ‘Low Renewable Cost’ sensitivity assumes capital cost reductions that are double those of the Reference Case. For solar PV, this represents a technological breakthrough, yielding system costs in 2030 that approach the DOE Sunshot goal of $1/W. The ‘High Renewable Cost’ sensitivity assumes no change in capital cost for any technology relative to today’s costs. The resulting costs of generation for systems installed in 2030 are summarized in Table 36. These costs were applied to all renewable resources above and beyond the contracts already signed by utilities; however, the cost of the utilities’ existing contracts was held constant across these scenarios to reflect the fact that the prices for these contracts have already been negotiated.

Table 36: Renewable resource cost sensitivities

Sensitivity	Residential Rooftop Solar PV ($/MWh)	Utility Scale Solar PV ($/MWh)	Utility Scale Wind ($/MWh)
Base Case	$278	$107	$99
High Renewable Costs	$377	$145	$106
Low Renewable Costs	$179	$70	$91

[51] The impact of this cost reduction on California ratepayers is counteracted by the assumed expiration of federal tax credits for renewables, which this analysis does not assume are renewed. For more detail on the derivation of cost assumptions for renewable resources see Section 2.5.1.

The effects of varying renewable costs are shown in Figure 42.

- The impact of the renewable cost sensitivity is lowest in the 33% RPS portfolio and highest in the 50% Rooftop Solar portfolio.
- The sensitivity of retail rates to the costs of renewables is low: even in the 50% RPS portfolio sensitivities, radical changes in the pricing of renewables causes variances in retail rates of 1-3%. The limited sensitivity is in part a result of the assumption that procurement that has already occurred is not affected by future changes to renewable costs.

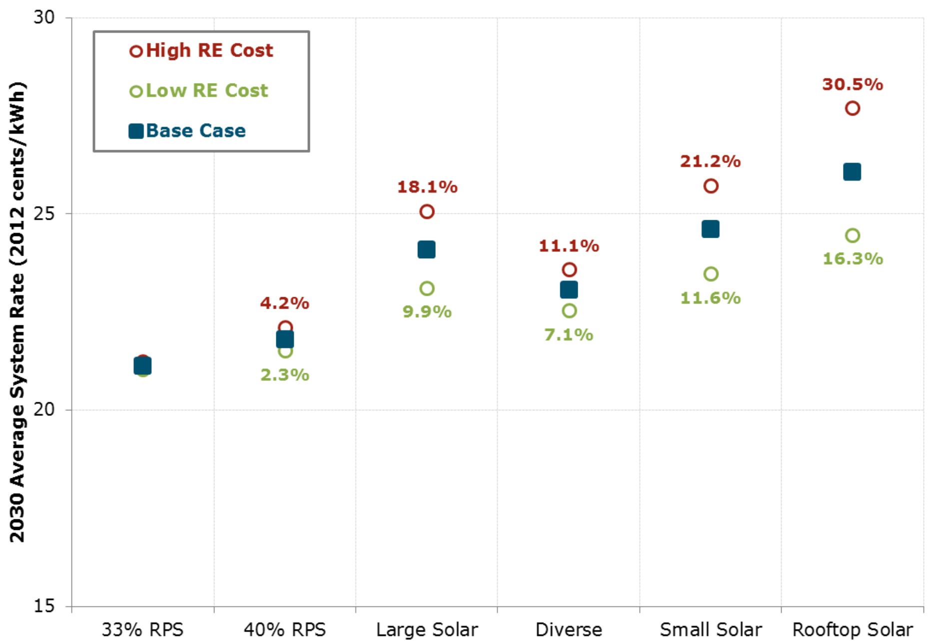

Figure 42: Sensitivity of retail rates to renewable resource costs (percentage change relative to 33% RPS Scenario applicable sensitivity)

5.4.4 SUMMARY OF KEY SENSITIVITY RESULTS

Table 37 provides a summary of the sensitivity analysis across all five 2030 Scenarios. The analysis reveals several interesting findings:

- Under a wide range of CO_2, natural gas and renewable energy prices, the higher RPS Scenarios result in an increase in average electric rates relative to the 33% RPS Scenario. The rate impacts are lowest under the high gas and CO_2 price sensitivity with low renewable energy costs.
- The rank order on costs between the Scenarios stays the same under all uncertainty ranges considered. The cost differences between these sensitivity results are reduced when assuming lower solar PV costs than in the base case.

Table 37. Summary of sensitivity analysis results

	33% RPS	40% RPS	50% RPS Large Solar	50% RPS Diverse	50% RPS Small Solar	50% RPS Rooftop Solar
Average System Rate (2012 cents/kWh)						
Base	21.1	21.8	24.1	23.1	24.6	26.1
Low Gas	19.8	20.6	23.0	22.0	23.5	25.0
High Gas	22.9	23.4	25.5	24.4	26.0	27.5
Low CO_2	20.5	21.2	23.6	22.5	24.1	25.6
High CO_2	22.6	23.1	25.2	24.2	25.7	27.2
Low RE Cost	21.0	21.5	23.1	22.5	23.5	24.5
High RE Cost	21.2	22.1	25.1	23.6	25.7	27.7
Low Gas & CO_2, High RE Cost	19.2	20.3	23.5	22.0	24.1	26.1
High Gas & CO_2, Low RE Cost	24.2	24.4	25.6	25.0	26.0	27.0
Percentage Change in Average System Rate (relative to 33% RPS)						
Base	n/a	3.2%	14.0%	9.1%	16.4%	23.4%
Low Gas	n/a	4.1%	16.5%	11.3%	19.1%	26.5%
High Gas	n/a	2.2%	11.3%	6.6%	13.5%	19.9%
Low CO_2	n/a	3.6%	15.2%	10.2%	17.7%	24.9%
High CO_2	n/a	2.4%	11.8%	7.1%	14.0%	20.6%
Low RE Cost	n/a	2.3%	9.9%	7.1%	11.6%	16.3%
High RE Cost	n/a	4.2%	18.1%	11.1%	21.2%	30.5%
Low Gas & CO_2, High RE Cost	n/a	5.7%	22.3%	14.7%	25.8%	36.0%
High Gas & CO_2, Low RE Cost	n/a	0.7%	5.8%	3.1%	7.2%	11.3%

5.4.5 ADDITIONAL SENSITIVITIES

This subsection presents the results of additional sensitivity analysis on several other assumptions, specifically the cost of overbuilding the renewable portfolio to ensure deliverability of 50% RPS energy and the expiration of state and federal renewable energy tax incentives. Results for cost sensitivities are presented below in Table 38.

5.4.5.1 Renewable overbuild cost sensitivity

Because of overgeneration, more renewable resources must be procured than would be the case if all renewable resource output could be accommodated by the grid. In the results presented above, the renewable resource overbuild is consistent with the scenario definition, i.e. the overbuild consists of mostly large solar resources in the Large Solar Scenario, small-scale solar resources in the Small Solar Scenario, etc. Another key assumption is that California is responsible for balancing all renewable resources that are delivered to California loads. Together, these two assumptions result in very high marginal cost for new renewable energy that is needed to make up for curtailment, and these make up a significant portion of the cost of meeting a 50% RPS.

It may be possible to address the renewable overbuild by procuring unbundled renewable energy credits (RECs), or by acquiring renewable resources in other regions without necessarily delivering them to California loads. In order to test the sensitivity of the results to these assumptions, we assume that:

- California acquires out-of-state RECs to meet the renewable overbuild requirements, and
- RECs are available at a cost of $100/MWh.

This assumption reduces the total cost (revenue requirement) of achieving a 50% RPS by $2.7 billion in the Large Solar Scenario, $0.5 billion in the Diverse Scenario, $3.3 billion in the Small Solar Scenario, and $5.1 billion in the Rooftop Solar Scenario. Rate impacts are cut by 10-39%; for example, the rate increase for the Large Solar Scenario is 9.3%, compared to 14.0% under base case assumptions.

5.4.5.2 Renewable tax incentives remain in place

This study assumes no changes to current federal and state law, except for the RPS mandate. As a result, federal and state tax incentives with sunset provisions are assumed to expire consistent with current statute. This sensitivity tests the effect of assuming that tax incentives remain in place through 2030.

This cost sensitivity assumption reduces the cost of all renewable energy that is procured above the quantity that is required to meet 33% by 2020[52]. As a result, costs are slightly lower in the 33% and 40% RPS Scenarios. The cost of achieving a 50% RPS is reduced by $2.3 billion in the Large Solar Scenario, $1.9 billion in the Diverse Scenario, $2.6 billion in the Small Solar Scenario, and $3.5 billion in the Rooftop Solar Scenario. Rate impacts of moving from 33% to 50% are reduced by approximately 25%; for example, the rate increase for the Large Solar Scenario is 10.8%, compared to 14.0% under base case assumptions.

[52] The cost for achieving 33% by 2020 was provided by the utilities, and is assumed not to be affected by extension of tax incentives.

Table 38: Results of additional cost sensitivities

	33% RPS	40% RPS	50% RPS Large Solar	50% RPS Diverse	50% RPS Small solar	50% RPS Rooftop Solar
2030 Revenue Requirement (2012 $ billion)						
Base	56.9	58.8	64.9	62.1	66.3	70.3
Tax Credit Extension	56.5	57.8	62.6	60.3	63.7	66.8
$100/REC	56.9	58.7	62.3	61.6	63.0	65.1
2030 Average System Rate (2012 cents/kWh)						
Base	21.1	21.8	24.1	23.1	24.6	26.1
Tax Credit Extension	21.0	21.5	23.2	22.4	23.6	24.8
$100/REC	21.1	21.8	23.1	22.9	23.4	24.2
Percentage Change in 2030 Average System Rate (relative to 33% RPS)						
Base	0.0%	3.2%	14.0%	9.1%	16.4%	23.4%
Tax Credit Extension	0.0%	2.4%	10.8%	6.7%	12.8%	18.2%
$100/REC	0.0%	3.0%	9.3%	8.2%	10.6%	14.4%

6 Conclusions

6.1 Next Steps

Although the focus of this study is on grid operations with very high renewable penetrations in 2030, there are a number of shorter-term “least-regrets” opportunities that the evidence in this report suggests should be implemented prior to or in parallel with a higher RPS standard. The four “least regrets” opportunities identified in this study include:

1. **Increase regional coordination.** This study shows that increased coordination between California and its neighbors can facilitate the task of efficiently integrating more renewable resources into the bulk power system at a lower cost. Although California already depends on its neighbors for imports during summer peak periods, an increased level of coordination across the West would include more sharing of flexible resources to support better integration of the rich endowment of wind energy in the Pacific Northwest and Rocky Mountains and solar resources in the Desert Southwest.
2. **Pursue a diverse portfolio of renewable resources.** The study shows that increasing the diversity of resources in California’s renewable energy portfolio has the potential to reduce the need for managed curtailment. More diverse renewable generation profiles can better fit within California’s energy demand profile. The benefits of developing a diverse portfolio are complemented by and in many ways tied directly to increased regional

coordination, since the largest benefit is likely to be achieved through increased geographic diversity across a wide area.

3. **Implement a long-term, sustainable solution to address overgeneration before the issue becomes more challenging.** A long-term, sustainable implementation and cost-allocation strategy to manage the potential large amounts of overgeneration that could result from a higher RPS should be developed before overgeneration jeopardizes reliability, and before curtailment impacts financing of new renewable generation projects. A long-term, sustainable solution must be technically feasible, economically efficient and implementable in California. It must include a mechanism for ensuring that renewable developers continue to receive a sufficient return to induce investment in projects on behalf of California ratepayers.
4. **Implement distributed generation solutions.** Increased penetration of distributed generation necessitates a more sustainable, cost-based strategy to procure distributed generation. This requires a reexamination of retail rate design and net energy metering policies, as well as implementation of distribution-level solutions and upgrades, including smart inverters with low-voltage ride-through capabilities that allow distributed photovoltaic systems to operate under grid faults.

There are also a number of key areas for future research that are beyond the scope of this study, but are critical to enable the bulk power systems to continue to work reliably and efficiently in the future. These include:

+ **The impact of a combined strategy of multiple renewable integration solutions.** This study finds that grid integration solutions will be critical to achieving a higher RPS at lowest cost. Because each solution has its own specific costs and benefits, a critical next step is to analyze combinations of these potential solutions to help develop a more comprehensive, longer-term grid integration solution to higher RPS.

+ **Research and development for technologies to address overgeneration.** Technology needs to support higher renewable energy penetration and to address the overgeneration challenge include diurnal energy flexibility and efficient uses for surplus solar generation during the middle of the day. Promising technologies include:
  - Solar thermal with energy storage;
  - Pumped storage;
  - Other forms of energy storage including battery storage;
  - Electric vehicle charging;
  - Thermal energy storage; and
  - Flexible loads that can increase energy demand during daylight hours.
+ **Technical potential and implementation of solutions.** This study points to the need for solutions to renewable integration challenges to be planned and implemented on the same timeline as, or before, higher renewable penetration. However, the technical potential to achieve each solution is unknown at this time. A significant effort is needed to characterize the technical potential, cost, and implementation challenges for pumped storage, battery technologies, upwardly-flexible loads, more diverse renewable resource portfolios, and other potential renewable integration solutions.
+ **Sub-five minute operations.** A better understanding of the sub-five minute operations, including frequency, inertia and regulation needs, under a higher RPS is needed. This is particularly pressing in California where significant changes are planned to the state's existing thermal generation fleet, including the retirement of coastal generators utilizing once-through

cooling. Research is needed regarding potential costs and the feasibility and performance of potential solutions, such as synthetic inertia.

- **Size of potential export markets for excess energy from California.** California has historically been an importer of significant quantities of electric energy. Under a 50% RPS, California would have excess energy to sell during many hours of the year. The extent to which electricity providers in other regions might be willing to purchase excess energy from California is unknown. This study assumes that California can export up to 1500 MW of energy during every hour of the year based on a high-level assessment of supply and demand conditions in other regions, and shows that higher levels of exports could significantly reduce the cost of achieving a 50% RPS. Further research might be able to shed additional light on this question.
- **Transmission constraints.** This study does not include an assessment of transmission constraints within California, and how those constraints might impact renewable integration results including reliability, cost and overgeneration. For example, if a large proportion of the solar energy resources modeled in this study are located in Southern California, northbound transmission constraints on Path 15 and Path 26 may result in significantly higher overgeneration than is indicated in this study. Challenges may also be more acute within the BANC and LADWP Balancing Authority Areas, which have limited transfer capability to the CAISO system.
- **Changing profile of daily energy demand.** Daily load shapes are expected to evolve over time, with increases in residential air conditioning and electric vehicle loads. This could shift the peak demand period farther into the evening, potentially exacerbating the overgeneration challenge during daylight hours.
- **Future business model for thermal generation and market design.** This analysis points toward a fundamental shift in how energy markets are likely

to operate under high penetration of renewable energy. Energy markets are unlikely to generate sufficient revenues to maintain the flexible fleet of gas generation that the state will need to integrate high levels of renewable energy. Moreover, there may be a significant number of hours in which market prices are negative. New market products for flexibility, inertia, frequent startups and capacity may be necessary to ensure that the generation fleet maintains the necessary operating characteristics.

+ **Optimal thermal generation fleet under high RPS.** Procurement choices will need to be made regarding trade-offs between combined-cycle gas generators, frame and aeroderivative combustion turbines, and other technologies with newly-important characteristics for renewable integration, such as low minimum generation levels and high ramp rates. The flexibility needs of the state's thermal fleet may also interact with local air quality regulations, which limit the number of permitted power plant starts.

+ **Natural gas system impacts and supply.** Operating the grid under a higher RPS may require more flexibility in the natural gas delivery system and markets. Whether the natural gas delivery system can support the simultaneous operation of gas-fired generators necessary for renewable integration is an important area for further research.

+ **Operational challenges of a 40% RPS.** The study finds that overgeneration occurs at 33% RPS and is significant at 40% RPS, but does not evaluate the impact of renewable integration solutions at a 40% RPS in detail.

+ **Cost-effectiveness of a higher RPS relative to other measures for reducing GHG emissions.** This study indicates that a 50% RPS may be a relatively high-cost means of reducing GHG emissions (over \$300/ton, as compared to CO_2 allowance price forecasts of \$30-100/ton). To be sure, there are many other benefits from higher renewable penetration besides GHG reduction. Nevertheless, it would be instructive to compare the cost of a 50% RPS with the cost of reducing GHG emissions in other sectors such as transportation, industry and buildings.

6.2 Summary

This study assesses the operational impacts, challenges, costs, greenhouse gas reductions, and potential solutions associated with a 50% RPS in California by 2030. The study finds that renewable integration challenges, particularly overgeneration during daylight hours, are likely to be significant at 50% RPS. The study indicates that at high penetrations of renewable generation, some level of renewable resource curtailment is likely to be necessary to avoid overgeneration and to manage net load ramps.

The study also identifies a number of promising integration solutions that could help to mitigate overgeneration, including procurement of a diverse portfolio of renewable resources, increased regional coordination, flexible loads, and energy storage. Achievement of a higher RPS at least cost to electric customers will likely require implementation of a portfolio of integration solutions, timely implementation of these solutions is critical but would likely involve substantial challenges related to cost, feasibility, and siting.

In this study, a 50% RPS is shown to lead to higher electric rates than a 33% RPS under a wide range of natural gas prices, CO_2 allowance prices, and renewable resource costs. The lowest-cost 50% RPS portfolio modeled here is one with a diversity of renewable resource technologies. The highest-cost portfolio modeled is one that relies extensively on rooftop solar photovoltaic systems.

This study highlights the need for additional research in a number of areas, including the need to address sub-five-minute operational issues, ensure sufficient power system flexibility, and develop strategies to avoid overgeneration.

Appendix

Appendices

Investigating a Higher Renewables Portfolio Standard in California

January 2014

Energy+Environmental Economics

Appendices

Investigating a Higher Renewables Portfolio Standard in California

January 2014

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A. Capacity Needs Assessment under High RPS

A.1 Capacity Needs Assessment Approach

This section describes how each of the 2030 scenarios is evaluated to ensure that there is sufficient capacity available within the fleet of convention and renewable generation to meet a common reliability standard. This standard is defined as no more than one loss-of-load event in 10 years. This capacity needs assessment ensures that the REFLEX modeling does not show loss of load events related to insufficient capacity rather than insufficient flexibility.

The capacity needs assessment uses E3's Renewable Energy Capacity Planning (RECAP) Model developed for the CAISO. RECAP uses standard industry techniques to calculate loss-of-load frequency (LOLF), loss-of-load expectation (LOLE), loss-of-load duration (LOLD), and expected unserved energy (EUE). Using any of these metrics, RECAP calculates effective load carrying capability (ELCC) as the amount of load served by an incremental generator without decreasing reliability.

The RECAP model uses industry standard methods for assessing power system reliability[1,2]. First, the RECAP model creates sample years by randomly sampling loads, renewables, monthly hydroelectric capacity, generator outages and maintenance. This sampling process mirrors the process for creating inputs for stochastic production simulation; however, because identifying capacity shortages in RECAP does not require solving for generator dispatch, the model can run a much larger set of years efficiently.

Generator outages are modeled using an exponential distribution for mean time to failure and mean time to repair. Generator maintenance is spread throughout months that show the largest capacity surpluses during the initial RECAP runs. Figure 1 shows the expected generator outage by month due to forced outage and maintenance, using data provided by the CAISO, out of a total dispatchable (excluding hydro and including demand response) capacity of 42,318 MW.

[1] R. Billinton and R. N. Allan, Reliability Evaluation of Power Systems, Second ed. New York: Plenum Press, 1996
[2] R. Billinton and W. Li, Reliability Assessment of Electric Power Systems Using Monte Carlo Methods. New York: Plenum Press, 1994.

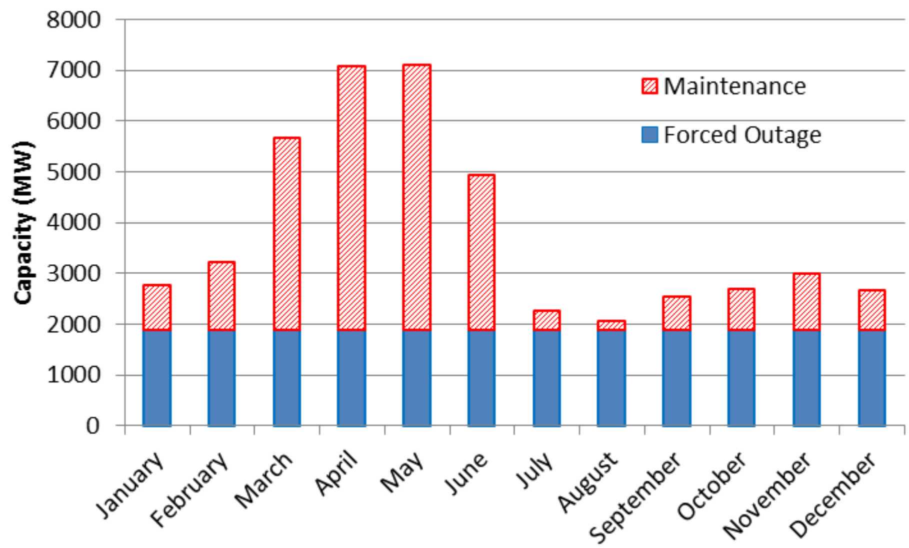

Figure 1: Average generation capacity outages due to forced outage or maintenance by month

For the RECAP model, load and renewable draws are done by month and day-type. The draws use stratified sampling so that the highest 20% of load days are paired with renewable profiles that occur during a high-load day. In this way non-time synchronous loads and renewables can be paired, increasing the richness of the dataset, while enforcing correlations during high load days.

Hydroelectric capacity is set by month based on a measure of maximum historical production. The maximum is used because, while precipitation levels strongly impact the hydro energy budget, hydro's maximum power output to avoid unserved energy is not significantly degraded. The net simultaneous import capability is 12,400 MW (1,862 MW of which is modeled explicitly as out-of-state generators in the stack), and is assumed to be available year-round.

A.2 Capacity Needs Assessment Results

For purposes of determining capacity need, a loss of load frequency (LOLF) of 0.1, or 1-day-in-10 years, is targeted. The reliability statistics for the 33%, 40%, 50% Large Solar, and 50% Diverse Scenarios are shown in Table 1 after a simulation of 5,000 years of load and resource data. Since the generation profile for the 50% RPS Large Solar Scenario is very similar to the Small Solar and Rooftop Solar Scenarios, the RECAP results for the Large Solar Scenario are treated as equally applicable to the Small Solar and Rooftop Solar Scenarios.

The 33% RPS case does not meet the 1-day-in-10 years planning criterion, without the addition of 615 MW of incremental capacity, as shown in Table 2. The 40% and 50% RPS scenarios have the same thermal generation fleet as the 33% RPS scenario but include much more renewable resources. As a result, the 40% and 50% RPS scenarios meet the 1-day-in-10 years planning criterion (with a LOLF below 0.1) without the need for additional capacity.

Table 1: Reliability statistics related to capacity need for 2030 RPS scenarios

	LOLF (events/year)	LOLE (hours/year)	EUE (MWh/Year)
33% RPS	0.15	0.29	371
40% RPS	0.09	0.16	245
50% RPS Large solar	0.07	0.12	193
50% RPS Diverse	0.03	0.04	50

Using these capacity need reliability statistics, Table 2 shows the amount of over-capacity (negative) or under-capacity (positive) in each of the RPS cases to meet the 1-in-10 standard. As a result, the 33% RPS case requires 615 megawatts of new capacity procurement and the 40% and 50% RPS scenarios do not require additional capacity. No new resources are needed for the 40% RPS or 50% RPS Large Solar and Diverse Scenarios. Rather, the addition of incremental renewable generation in these scenarios results in some surplus of capacity. These capacity savings are reflected in the total cost of the 40% and 50% RPS Scenarios described in Section 5.

Table 2: Resource need/surplus to achieve 1-in-10 LOLF in 2030 (MW)

Scenario	Resource need/(surplus) (MW)
33% RPS	615
40% RPS	(150)
50% RPS Large Solar	(762)
50% RPS Diverse	(2764)

Conventional resources and loads are equal across all scenarios, thus the reliability differences between the cases are solely due to the renewable resources' contribution to resource adequacy. The contribution of the renewables towards meeting resource adequacy needs is determined by measuring the conventional capacity needed to maintain the same level of reliability when those RPS resources are removed from the portfolio in the RECAP model. This is known as the resources' Effective Load-Carrying Capability (ELCC). Figure 2 shows the nameplate installed capacity and the ELCC of the renewable resources as the RPS percentage increases.

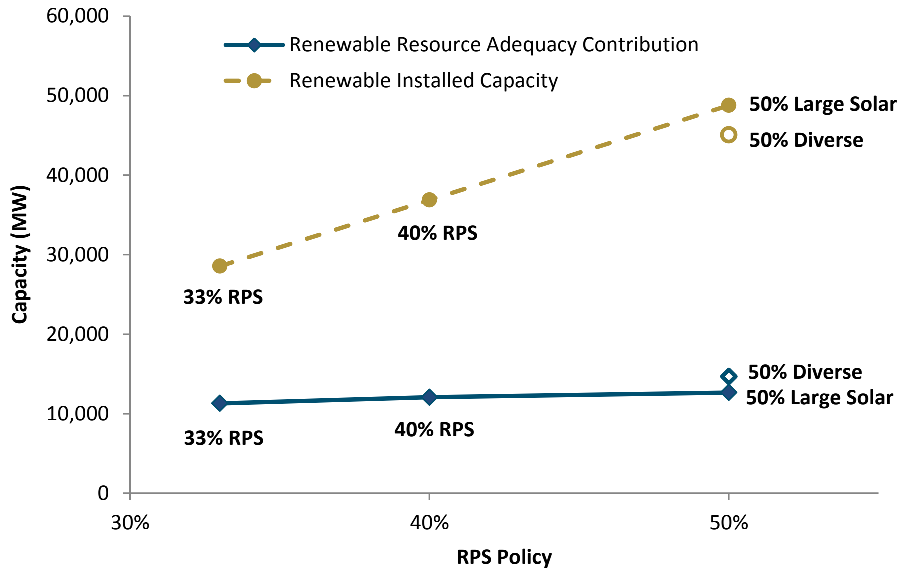

Figure 2: Renewable nameplate capacity and resource adequacy contribution for the 33% RPS, 40% RPS, 50% RPS Large Solar 50% Diverse Scenarios

The figure shows that as the nameplate capacity of installed renewable resources increases between the 33% RPS, 40% RPS and 50% RPS Scenarios, the effective contribution of the additional renewables to meeting the resource adequacy standard is relatively small. The contribution of wind and solar towards meeting resource adequacy increases by only 1,377 MW between the 33% RPS the 50% Large Solar Scenario, despite the addition of 20,236 MW of nameplate wind and solar capacity.

Table 3 shows the same data as Figure 2 in tabular format. To achieve a 33% RPS, 28,544 MW of renewables are installed, resulting in 11,292 MW of effective capacity that contributes to resource adequacy. Moving from 33% to 40% RPS requires 8,332 MW of additional renewable capacity; however, these resources provide only 765 MW of resource adequacy benefit. Thus, the ELCC of this increment of resources is only 9% of nameplate capacity. This occurs because solar PV is the predominant resource that is added to move from 33% to 40% RPS. The solar resources provide lower capacity value than nameplate capacity due, in part, to the fact that in the 2030 high renewable penetration scenarios, the net peak occurs later in the day, and later in the year, relative to today, when the sun is not shining and solar PV is not producing energy.

Table 3: Incremental 2030 renewable resource additions and contribution to resource adequacy for 40% RPS and 50% RPS scenarios

	RPS Installed Nameplate Capacity (MW)	RPS Resource Adequacy Contribution (MW)	ELCC of Incremental wind and solar PV
33% RPS	28,544	11,292	40%
From 33% to 40% RPS	8,332	765	9%
From 40% to 50% Large Solar	11,904	612	5%
From 40% to 50% Diverse	8,194	2,614	32%

Moving from 40% to the 50% Large Solar Scenario requires 11,904 MW of additional resources, these resources provide only 612 MW of resource adequacy benefit, for an average ELCC of 5%. The resources added in the Diverse Scenario provide more resource adequacy value; 8,194 MW of resources are added, providing 2,614 MW of resource adequacy. The higher resource adequacy value of the Diverse Scenario is explained in part by the additional biomass and geothermal resources which provide a dependable capacity resource during 2030 net peak demand periods. The Diverse Scenario also includes additional out-of-state wind resources, which along with new transmission, contribute to meeting the reliability target. Finally, the Diverse

Scenario also includes solar thermal with storage which produces power into the evening hours when the 2030 net peak demand period is expected to occur.

B. REFLEX

B.1 REFLEX

B.1.1 STOCHASTIC APPROACH

The REFLEX approach to flexibility planning focuses on creating a statistically robust picture of flexibility challenges and system operations. The model is stochastic in two ways: it randomly draws system conditions (load, renewables, hydro, outages, etc.) for each day of the simulation while imposing correlations where necessary; and the system operations include realizations of day-ahead and hour-ahead forecast errors in order to account for the flexibility limitations associated with imperfect information. The modeling approach is summarized by the diagram in Figure 3.

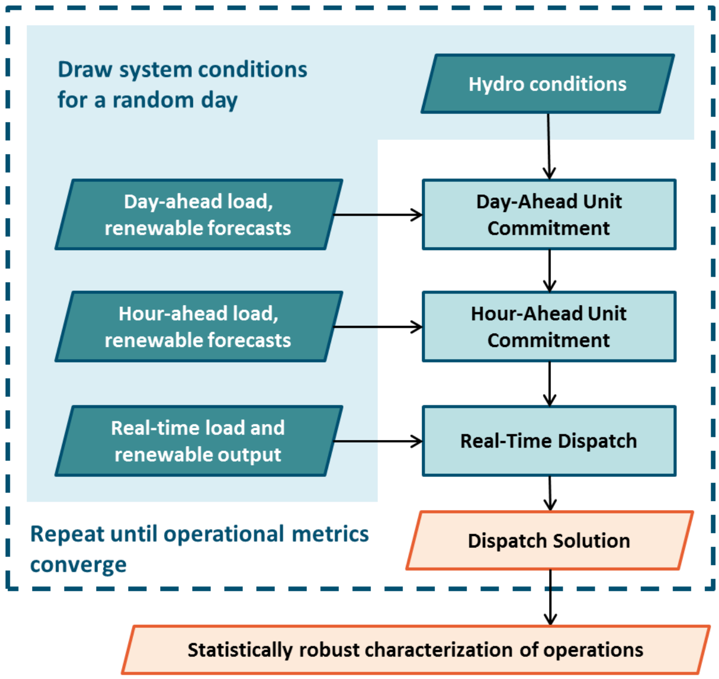

Figure 3: REFLEX modeling approach

B.1.2 UNIT COMMITMENT AND DISPATCH

The unit commitment and dispatch solutions are found in this analysis using an implementation of REFLEX in ProMaxLT, a production simulation platform. The unit commitment model solves for the least-cost dispatch given forecasts for the load and renewable power output, hydro conditions, unit-specific heat rates, and operational constraints for each unit including maximum power output, minimum stable level, minimum up time, minimum down time, and maximum ramp rate. REFLEX for ProMaxLT also includes endogenous reserve scheduling, which trades the cost of holding additional reserves against the cost of expected sub-hourly violations. The model effectively decides how much of a load following requirement to hold in each hour based on the system conditions and the expected unserved energy associated with various load following violations. A simplified penalty curve is shown for the hour-ahead unit commitment model in Figure 4.

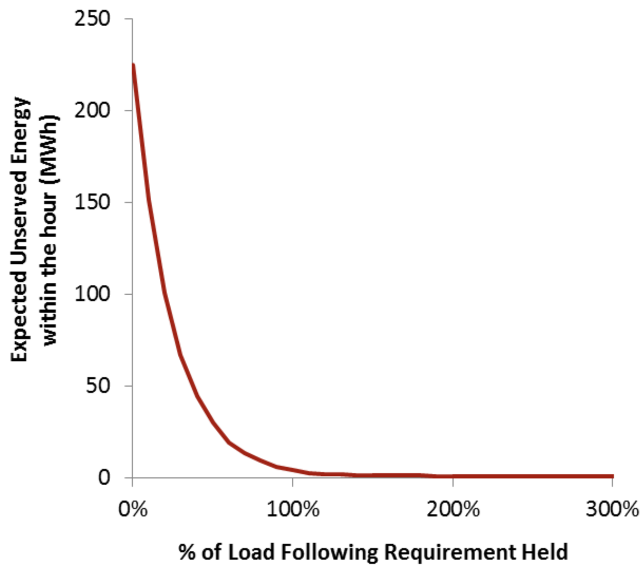

Figure 4: Simplified reserve scheduling penalty curve showing the expected unserved energy for various load following compliance policies

B.1.3 FORECAST ERROR

The forecast error is incorporated into unit commitment decisions in the day-ahead and hour-ahead time periods. E3 selected mean forecast errors that assume continued improvement in forecasting technology through 2030, particularly in the hour-ahead time period. To develop the forecast error, E3 creates load and renewable forecasts using a day-matching algorithm that works by pairing similarly shaped daily profiles, calling one the forecast of the other. Table 4 shows the forecast error assumptions used in the 2030 scenarios.

Table 4: 2030 mean absolute forecast error assumptions reflecting assumed improvement through 2030 (% of profile maximum)

	Day ahead unit commitment	Hour ahead unit commitment
load	0.7%	0.2%
wind	8.0%	4.0%
central solar	6.0%	1.0%
distributed solar	6.0%	1.0%

B.2 Sub-hourly Operations Results in REFLEX

The real-time dispatch simulation step provides granular information regarding the sub-hourly flexibility required by each system and the resources that provide it. Figure 5 illustrates this granularity for an example hour within an example day from the 50% RPS Large Solar simulation. In each hour, REFLEX selects the amount of upward and downward flexibility that is anticipated to be needed to meet sub-hourly fluctuations and forecast errors. These upward and downward flexibility provisions are analogous to a load following requirement and must be met with the conventional units that are committed in each hour. In the real-time dispatch simulation, the model steps through each 5-minute time step within the hour to test whether the committed units are capable of meeting the actual sub-hourly fluctuations and forecast errors. An example of this is shown in the zoomed in region in Figure 5.

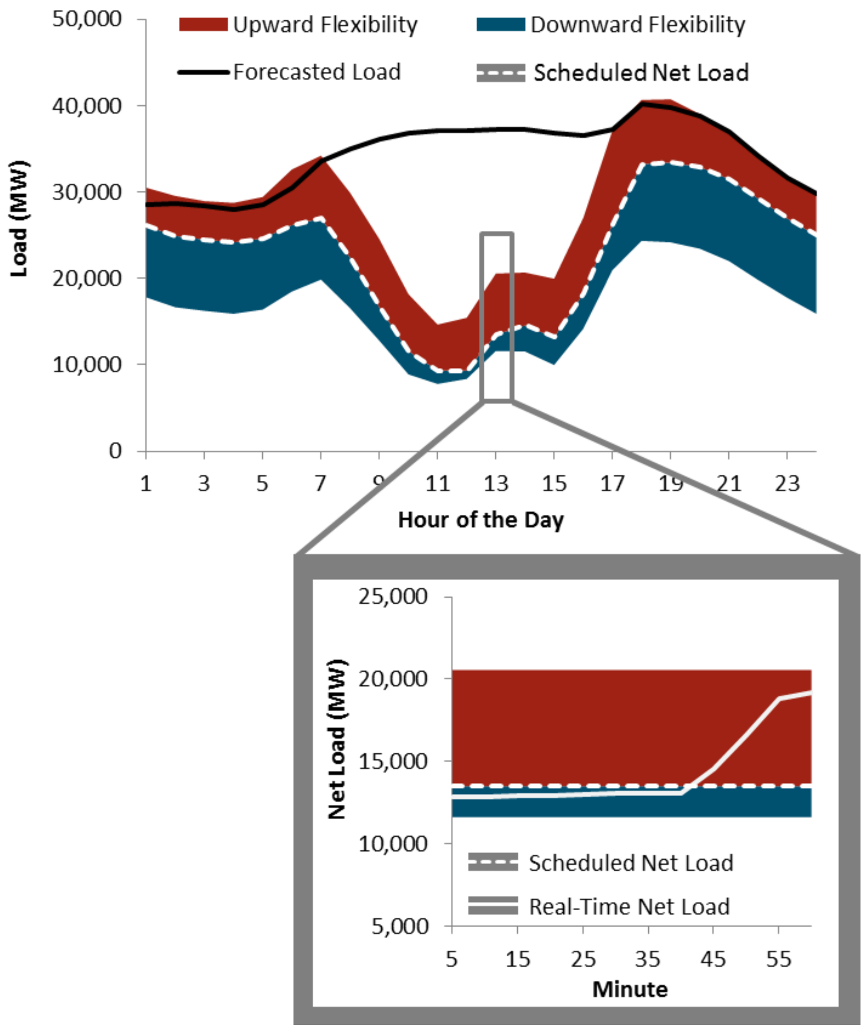

Figure 5: REFLEX treatment of flexibility provisions, sub-hourly fluctuations, and forecast errors on example day

Dynamic scheduling of the flexibility provisions is a unique feature of the REFLEX model. Figure 6 compares the average flexibility provisions scheduled by REFLEX for ProMaxLT throughout the day to traditional load following requirements. Because upward flexibility violations are more costly than downward flexibility violations, the model tends to schedule more upward flexibility provisions than downward flexibility provisions. REFLEX also allows renewable curtailment to contribute to meeting downward flexibility needs in real-time, with a costly penalty. In Figure 6(b), the effective downward flexibility provided by renewable curtailment is shown in addition to the downward flexibility provisions provided by the conventional fleet. Note that despite the significant potential of renewable curtailment to provide downward flexibility, the model instead chooses to rely on conventional units to provide downward ramping because it is more economical to do so.

Utilization of the flexibility provisions is shown in Figure 7. These histograms show the likelihood of utilizing a given percentage of the flexibility provision across all hours. For example, if the upward flexibility provision is 5,000 MW, then the likelihood that the balancing need is between 0 and 500 MW is 40%. This analysis suggests that the flexibility provisions selected by REFLEX are adequate to meet all 5-min fluctuations and forecast errors in at least 99.9% of all hours. The only violations that were identified by REFLEX were in the downward direction, and could therefore be met with renewable curtailment.

While the REFLEX simulations all relied on the conventional fleet and (to a lesser extent) renewables to provide sub-hourly flexibility, renewable integration solutions could also to contribute to meeting sub-hourly flexibility needs, including enhanced regional coordination, advanced demand response and flexible loads, and energy storage. The potential benefits of these renewable integration solutions to meeting sub-hourly flexibility needs are not modeled; this would be an interesting area for additional research.

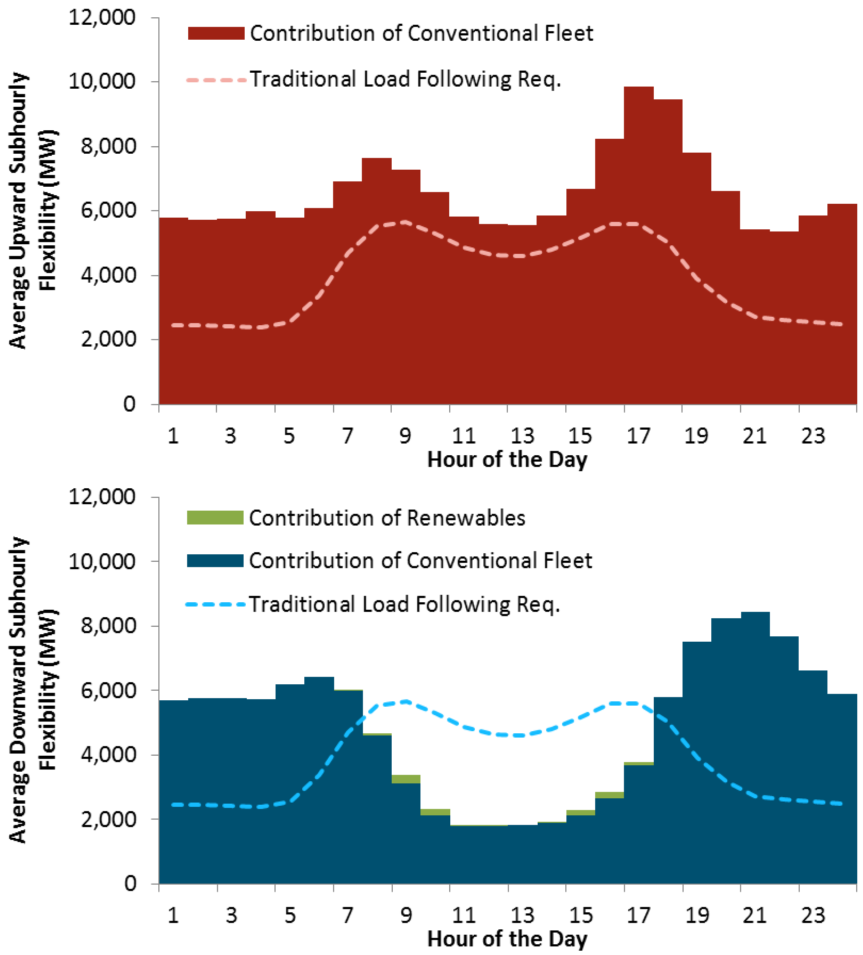

Figure 6: Average flexibility provisions calculated by REFLEX for ProMaxLT by hour of the day in (a) upward direction; and (b) downward direction

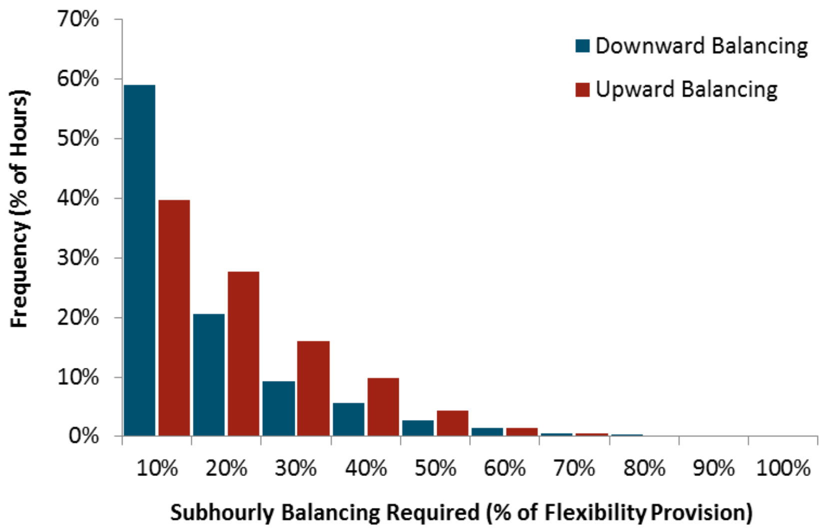

Figure 7: Histograms of percent utilization of flexibility provisions across all hours

B.3 Load Profile Assumptions and Methodology

A neural network-based approach is used to predict 2030 daily load energy under historical weather conditions. The neural network model is a non-linear regression approach using historical daily weather and solar data to create a predictive database of 63 years-worth of weather-matched daily load shapes, scaled to 2030 loads. These load shapes reflect the historical variability in load and weather in California and are used in the stochastic modeling approach employed by REFLEX. The approach towards generating 2030 load profiles is shown in Figure 8 and each step (1-4) is described in more detail below.

Step 1
Step 2
Step 3
Step 4

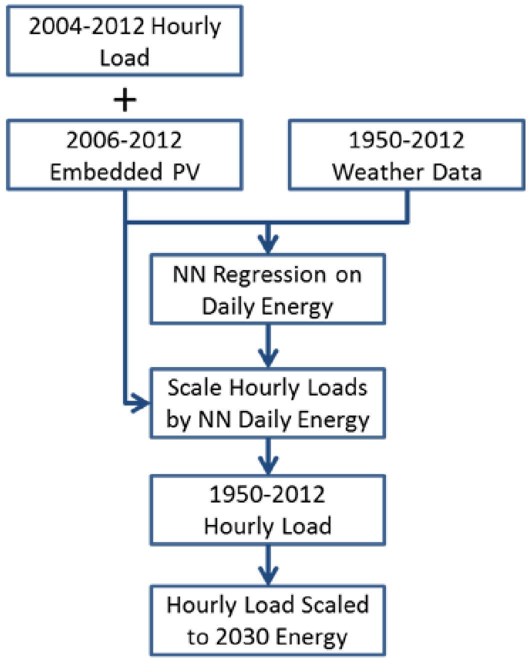

Figure 8: Methodology for creating 2030 load profiles

Step 1: Create an hourly aggregate load profile using CAISO, SMUD, and LADWP historical hourly loads for 2006-2012. The impact of behind-the-meter solar PV on historical load shapes is backed out of the data using simulated daily shapes and energy production for behind-the-meter PV from 2006-2012.[3] The behind the meter PV that is assumed to be embedded in the historical load data is shown in Figure 9, grossed up for transmission and distribution losses.

[3] The historical load data includes the impacts associated with increasing air conditioning loads over time, and other changes in end uses, which have resulted in system peak periods occurring later in the day than in the past.

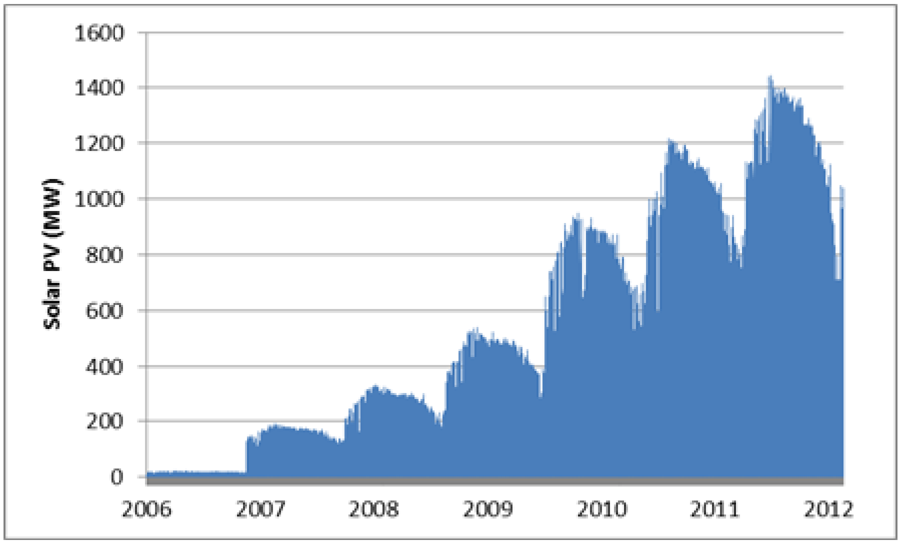

Figure 9: Simulated solar PV (2006-2012) including avoided losses

Step 2: Develop an artificial neural network model using the following explanatory variables to predict daily CAISO energy: temperature (daily high/low at eight California locations), lag/lead temperature (D-1,D-2,D+1) due to their impacts on heating and cooling load; a solar azimuth variable; a Boolean variable for the first half of the year (Day=1..183); a Boolean workday indicator; and a day number index that is utilized to capture any additional trends in the underlying load data not explained by other variables (economic factors, population growth, load types, etc.) (see Table 5). Figure 10 shows the model fit.

Table 5: Neural Network Variables

Explanatory Variable
Daily High Temperature: Burbank, Fresno, Ukiah, Long Beach, Riverside, Sacramento, San Francisco, San Jose
Daily Low Temperature: Burbank, Fresno, Ukiah, Long Beach, Riverside, Sacramento, San Francisco, San Jose
Solar Azimuth
First Half of Year {0,1}
Workday {0,1}
Day Number Index (ex. Jan 1, 2004=1)

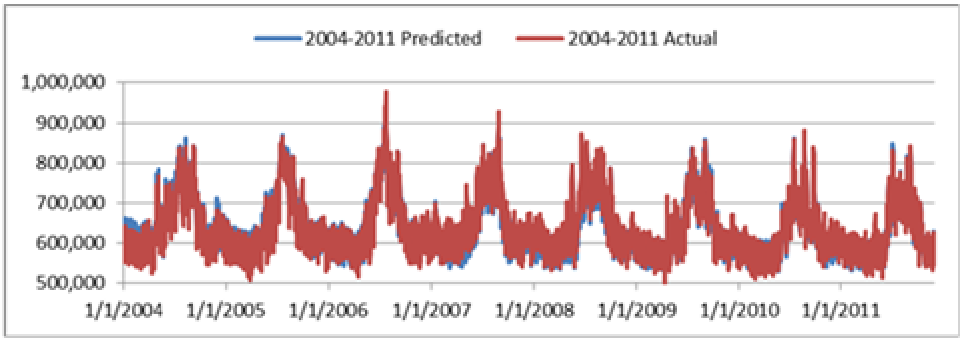

Figure 10: Predicted vs. actual CAISO daily energy for 2004-2011

The neural network model is used to predict daily energy for 2012 demographic and economic conditions under historic weather conditions. The result of the regression is shown in Figure 11 for CAISO load only.

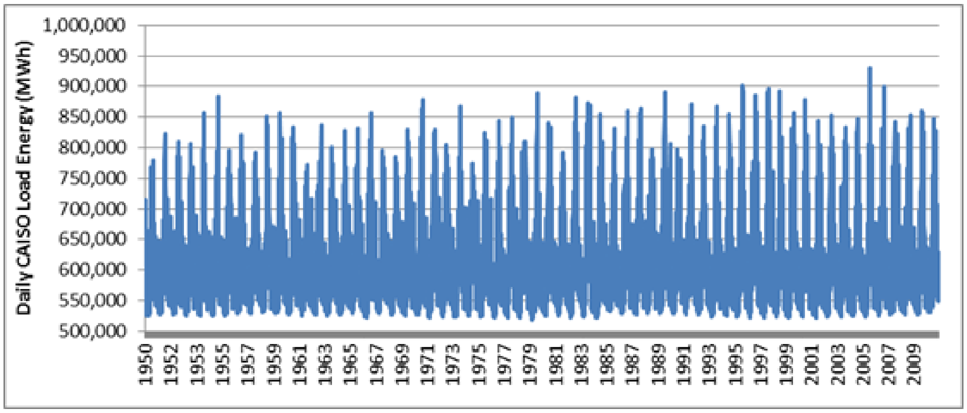

Figure 11: 1950-2011 CAISO daily energy

Step 3: Use a daily energy matching function to produce hourly load data starting from 1950. For all years without hourly data (1950-2003) the chosen normalized daily shape is multiplied by daily energy to produce hourly profiles. The normalized daily shape is chosen from those years where hourly data is available (2004-2012) based on the closest match of total daily energy. Matched days are within 15 calendar days of each other so that seasonally specific diurnal trends are preserved. In addition, weekdays and weekends are matched separately.

Step 4: The resulting 63 years of hourly load profiles are scaled to the expected 2030 energy. Electric vehicle charging schedules and behind-the-meter PV are introduced as separate profiles.

B.4 Imports/Exports Assumptions

The flexibility analysis simulates dispatch within California as a single zone; the rest of the Western Electricity Coordinating Council (WECC) is represented through import/export specifications that include both constraints and cost terms. Because of uncertainties around renewable and carbon policies as well as conventional generation procurement in the Northwestern and Southwestern US, the analysis is focused on gaining insight from import/export scenarios rather than building and relying on a WECC-wide 2030 forecast. Regional load growth forecasts through 2030 and current RPS policies are used to inform import/export specifications that appear likely to be technically feasible in 2030.

B.4.1 UNDERSTANDING THE WEST IN 2030

Historically, California has been a net importing region. Imports to the state are economic under most operating conditions due largely to inexpensive hydroelectric resources in the Pacific Northwest and relatively low cost fossil resources in the Southwest. The Pacific Northwest faces its own operational challenges managing its renewable and large hydroelectric resources, suggesting there may not be demand in the Pacific Northwest for excess power from California in the near future.

By 2030, however, load growth may give rise to a new operational paradigm in the Pacific Northwest that relies increasingly on thermal resources on the margin. A simple analysis was performed to inform the 2030 Pacific Northwest import/export scenario using data for the Northwestern balancing authorities from the TEPPC 2022 Common Case. In this analysis, the Pacific Northwest load, net of renewables, nuclear, hydro, and imports/exports from British Columbia is compared against the coal fleet to provide a sense of the region’s likely reliance on non-coal thermal resources in 2030. The analysis includes all conventional and renewable resources that are anticipated to be built by 2022 in the TEPPC 2022 Common Case.[4] Coal plants are conservatively assumed to be operating most, if not all, of the year in order to meet local demand in the Northwest. Any net load that exceeds the maximum dispatchability of the coal fleet is therefore assumed to be met with either gas-fired resources or exports from California. In these hours, it is also anticipated that the cost of imports from the Pacific Northwest will reflect gas-fired generation, rather than coal or hydroelectric power, and as such may not be economical for California. When the net load falls between the minimum output of the coal fleet and the maximum output of the coal fleet, the cost of imports from the Pacific Northwest are anticipated to reflect either hydro or coal resources and there is no guarantee that the hydro and/or coal plants will be able to ramp down to accept exports from California.

Loads for balancing authorities in the Pacific Northwest were scaled up to 2030 levels based on the WECC-wide load forecast growth rates in the TEPPC 2022 Common Case. Hydro and BC imports/exports were modeled based on historical hourly data and were allowed to redispatch to meet the net load (load minus baseload and wind) within each week based on a weekly energy budget while satisfying capacity constraints. This analysis was first performed for 2005 in order to validate the approach. Results are shown in Figure 12. As anticipated, the 2005 net load falls between the minimum and maximum dispatch levels of the Northwest coal fleet for most of the year, suggesting that California has access to inexpensive imports and that the Pacific Northwest may not have adequate

[4] The projected buildout of wind in the NW suggests that resources online by 2022 will be adequate to satisfy RPS requirements through 2030 when accounting for load growth, unless more aggressive RPS policies are adopted.

flexibility to accept exports from California. However in the winter, higher loads in the Northwest create a demand for California exports.

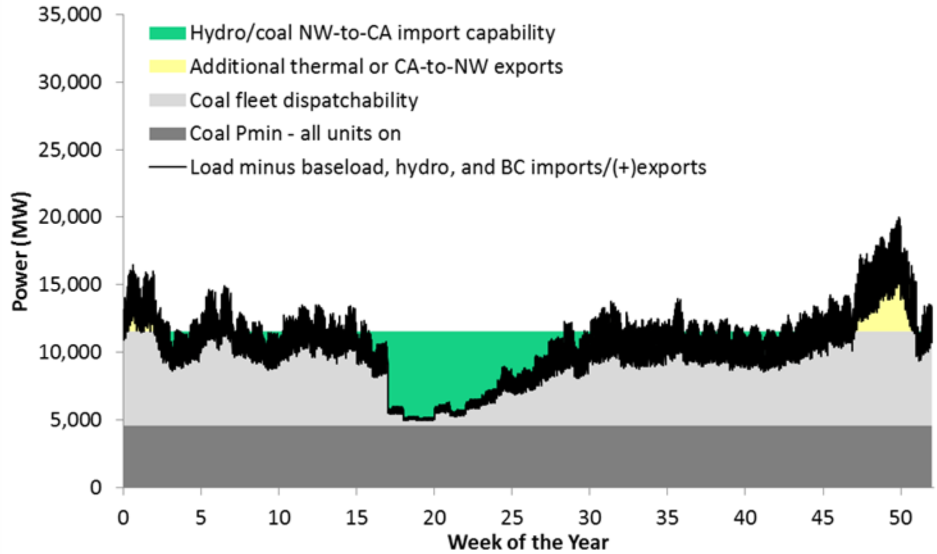

Figure 12: Historical benchmark of net load and resources in Northwest balancing authorities, 2005

The same analysis was repeated for 2030 (shown in Figure 13). The primary drivers for the difference between 2005 and 2030 are load growth and wind power development.

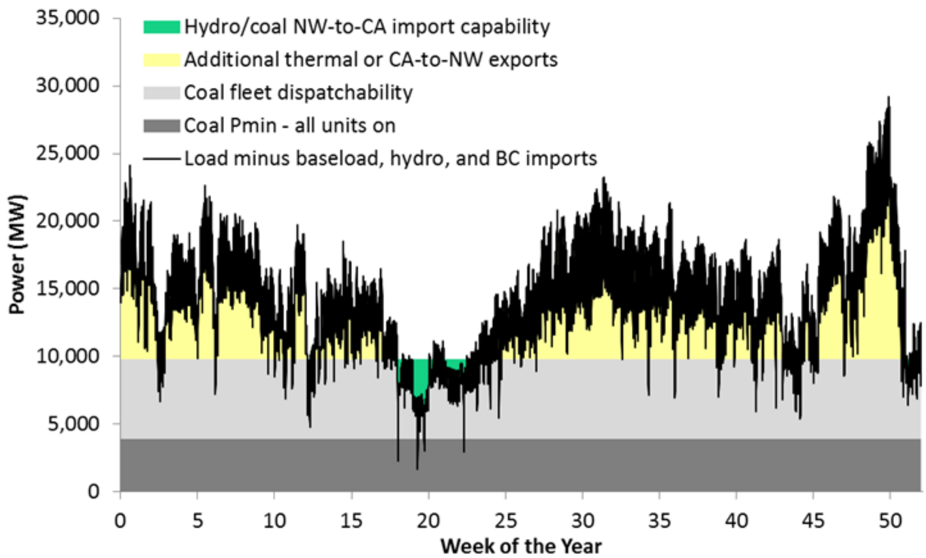

Figure 13: Projected net load and resources in Northwest balancing authorities, 2030

In the 2030 analysis, the Northwest's coal resources are no longer expected to be adequate to meet the net load throughout most of the year. This suggests that by 2030, current patterns regarding the import/export relationship between California and the Pacific Northwest may not hold. Throughout large portions of the year, the cost of imports from the Pacific Northwest may reflect gas-fired units on the margin rather than hydro or coal. In addition, the analysis suggests that by 2030 the Pacific Northwest may show increased demand for exports from California particularly in the winter and early spring, when California is anticipated to have excess renewable generation under a 50% RPS.

A similar analysis was performed for the Southwest. The region's 2030 renewable build-out to meet current RPS policy is assumed to be dominated by solar power. The Southwest analysis (shown in Figure 14) suggests that the demand for exports from California will likely be lowest in non-summer months and highest in the summer, when California is not anticipated to have excess renewable generation.

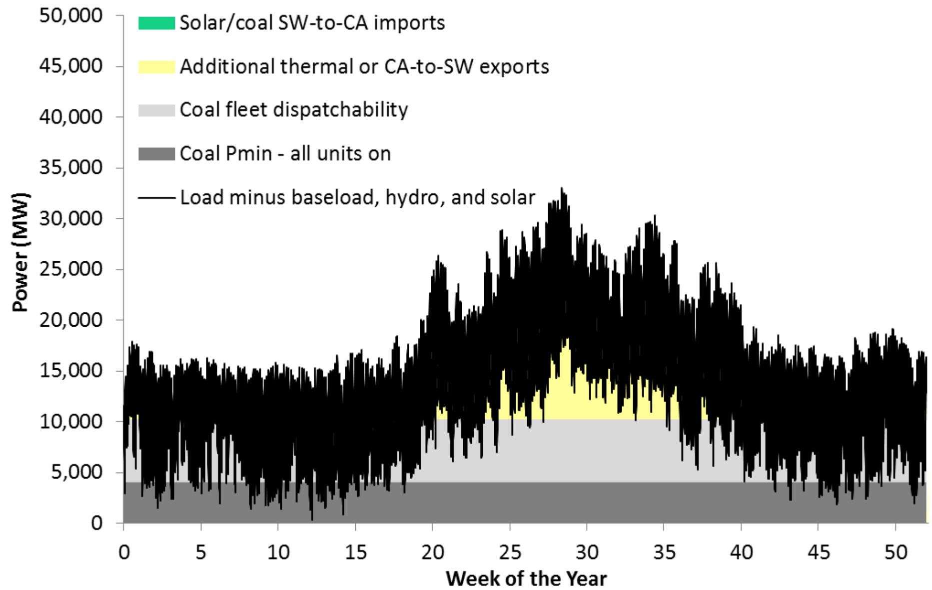

Figure 14: Projected net load and resources in Southwest balancing authorities, 2030

Furthermore, the anticipated solar build-out in the Southwest between now and 2030 means that if there is a demand for exports from California, it will likely not be during the daytime hours, in which both California and the Southwest have significant solar resources.

B.4.2 OVERALL IMPORT/EXPORT ASSUMPTIONS

The high-level 2030 analysis is not sufficient for determining the cost of imports into California or the demand for California's excess electricity in 2030, two important yet highly uncertain drivers of WECC-wide operations in 2030. For this reason, the flexibility modeling employs very simple assumptions regarding imports/exports that are consistent with the goals of this study. These assumptions include:

+ **Exports priced at zero.** In the flexibility modeling, exports help to avoid overgeneration conditions, subject to power and ramping constraints. In REFLEX for ProMaxLT, exports are given a conservative zero price, so that the model does not choose to commit additional thermal resources in order to create revenue from selling exports. To the extent that California could generate revenue from selling exported power, the exports described in this analysis likely represent a lower bound.
+ **Costly imports.** Imports from both the Northwest and Southwest are modeled assuming a marginal heat rate of 10,500 Btu/kWh, consistent with the study assumption that California prioritizes using its own resources to meet and balance its loads before relying on imports. This high marginal heat rate is also consistent with the conclusion from the analysis described above that hydroelectric resources are unlikely to operate on the margin in the Pacific Northwest by 2030.
+ **Conservative export limits.** In the base assumptions, exports are capped at 1,500MW, consistent with a level determined to be operationally feasible given today's transmission constraints. This constraint is relaxed to 6,500MW in the Enhanced Regional Coordination case.
+ **Historically-based import limits.** Import limits are set based on historical path flow data from WECC. The resulting import limits are presented below.

B.4.3 PATH FLOW LIMITS

Imports are modeled separately from the Pacific Northwest (NW) and the Southwest (SW). NW and SW imports are subject to maximum import levels and multi-hour ramp constraints. In addition, a simultaneous import limit is placed on the total imports (NW+SW). The maximum import level from the Northwest is derived from historical path flow data over PDCI and COI (see Figure 15). Based on the path flow distribution, the 99^{th} percentile was taken as the maximum allowable imports. This analysis was repeated with flows over Path 46 to determine Southwest import limits (Figure 16) and simultaneous flows over Path 46, PDCI, and COI to determine simultaneous import limits (Figure 17). The resulting path flow limits are described in Table 6 for both the base set of assumptions (used across all scenarios) and the Enhanced Regional Coordination Case. The historical path flow data was also used to derive ramp rate limits over various ramp durations. These are listed in Table 7.

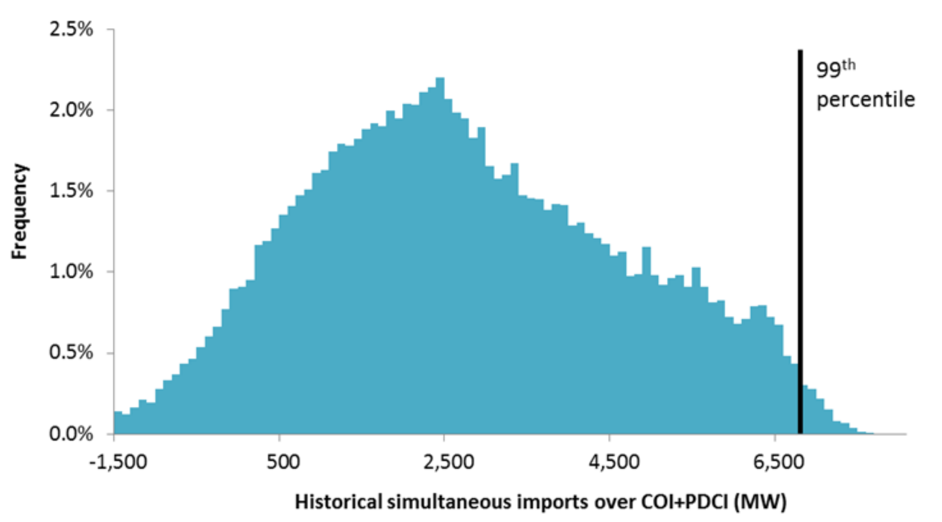

Figure 15: Histogram of historical path flow data used to derive the NW to CA import limits

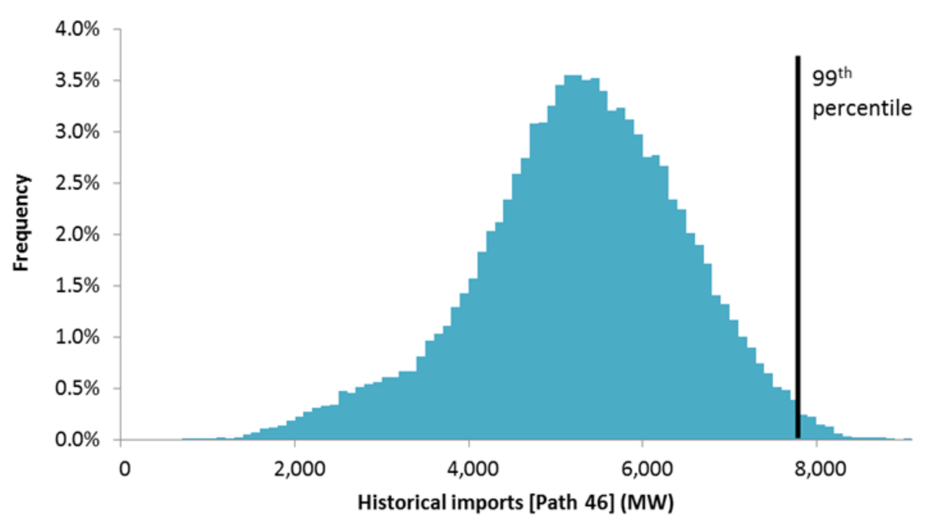

Figure 16: Histogram of historical path flow data used to derive the SW to CA import limits

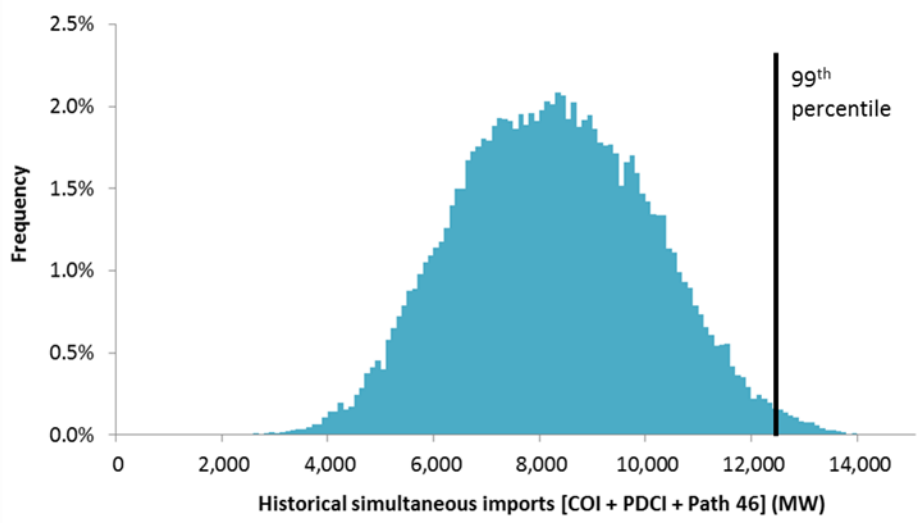

Figure 17: Histogram of historical path flow data used to derive the simultaneous import limits

Table 6: Import limits across all scenarios and in the Enhanced Regional Coordination Case

Base Assumptions	Northwest	Southwest	Simultaneous
Import Limit (into CA)	6,700 MW	7,700 MW	12,400 MW
Export Limit (out of CA)	1,500 MW	0 MW	1,500 MW
Enhanced Regional Coordination Assumptions	**Northwest**	**Southwest**	**Simultaneous**
Import Limit (into CA)	6,700 MW	7,700 MW	12,400 MW
Export Limit (out of CA)	3,250 MW	3,250 MW	6,500 MW

Table 7: Multi-hour ramping limits on imports/exports

	Northwest Ramp Limits		Southwest Ramp Limits	
Duration (hrs)	Ramp Down (MW)	Ramp Up (MW)	Ramp Down (MW)	Ramp Up (MW)
1	-1,200	1,200	-760	760
2	-2,000	2,000	-1,200	1,200
3	-2,600	2,500	-1,500	1,500
4	-3,100	2,900	-1,700	1,800
5	-3,500	3,300	-1,900	2,000
6	-3,800	3,500	-2,000	2,100
7	-4,000	3,800	-2,100	2,200
8	-4,200	4,000	-2,100	2,300
9	-4,300	4,200	-2,200	2,300

B.5 Hydropower Assumptions

B.5.1 CONVENTIONAL HYDROPOWER

Conventional hydropower is modeled as a single statewide aggregated resource and is constrained based on several years of historical data. The general approach applies a set of constraints that ensures that the hydro system dispatch represents physically and institutionally feasible operations. Rather than modeling specific hydro systems and the various technical and non-technical constraints imposed on river systems and reservoirs, the analysis relies on historical operational trends. Three sets of constraints are included in the hydro model: daily energy budgets, min/max power constraints, and ramping constraints.

B.5.1.1 Energy Budgets

Daily energy budgets ensure that the hydro dispatch respects both seasonal fluctuations in the availability of hydro power and seasonal fluctuations in the use of reservoirs to provide non-electrical services. Daily average energy budgets are calculated for every month of the year and hydro conditions dating back to 1970 based on EIA monthly hydro generation data. The data includes all conventional hydro units in the CAISO, BANC, and LADWP balancing areas. For each day in the simulation, a hydro year is randomly drawn and the average daily statewide conventional hydro energy budget for the corresponding month and hydro year is enforced over the simulation day. In REFLEX for ProMaxLT, three hours are modeled on either side of each day in order to remove edge effects. For this reason, the hydro budgets are scaled up to represent 30 hours, rather than 24. However, the model was allowed to push some of the daily energy budget into the edge hours rather than using it in the simulation day, allowing the hydro energy to fall short of its 24 hour daily budget. This downward flexibility represents on average about 25% of the daily energy budget.

B.5.1.2 Power Constraints

Minimum power constraints are imposed on the aggregated system to ensure that minimum flow requirements for river systems are respected, while maximum power constraints are imposed to ensure that the model does not overestimate the availability of hydro capacity in peak net load hours. The minimum and maximum power constraints are approximated using the output over the years 2001, 2005, and 2011 (based on hourly data from TEPPC). Over these years, the minimum power output was 120 MW and the maximum was 6,927 MW.

B.5.1.3 Multi-hour Ramping Constraints

The aggregated hydro system is also constrained with multi-hour ramping constraints to ensure that the hydro system does not provide more flexibility than has been used historically. These multi-hour ramping constraints were calculated as the 99th percentile of ramping events in the historical hourly data (2001, 2005, and 2011) from TEPPC.

B.5.1.4 Flexibility assumptions

The aggregated hydro system is scheduled in the day-ahead, rescheduled in the hour-ahead, and dispatched in 5-min real-time. The daily energy budget is enforced in each stage. The daily minimum and maximum power constraints and the multi-hour ramping constraints are enforced only in the day-ahead and hour-ahead commitment. In the 5-min dispatch, the hydro output is constrained to a band around its hour-ahead schedule equal in size to its 1-hour ramping limit.

B.5.2 RUN-OF-RIVER HYDROPOWER

Run-of-river hydro systems are modeled with constant non-curtailable power output over the course of each day, with a daily energy budget that scales according to the month and hydro year. The power output from run-of-river (ROR) systems is determined by scaling a monthly ROR shape to the annual conventional hydro generation in the selected hydro year. This monthly shape was generated with hourly hydro data for 2001, 2005, and 2011 from TEPPC. The hydro output was aggregated by conventional vs. ROR systems and the average power output of ROR systems as a fraction of the annual conventional hydro generation was calculated for each month.

B.5.3 PUMPED STORAGE HYDROPOWER

Helms (3 units), Eastwood, Hodges-Olivenhain and Castaic are modeled as pumped storage units in the model. All other pumped hydro systems are modeled as part of the state-wide hydro system. Castaic is modeled with fixed daily shapes based on a prior analysis by LADWP. The other pumped storage units are scheduled in the day-ahead, rescheduled in the hour-ahead, and dispatched in real-time. Pumped storage units are allowed to contribute to meeting spinning reserve, regulation, and flexibility reserve requirements when they are in generating mode. Where historical net generation data was available, this was used to constrain the daily energy budget. Efficiency parameters were set to 100% to avoid double-counting of pumping and generating inefficiencies. Since Hodges-Olivenhain has no operational data to date, the daily energy budget was set to 0 and the TEPPC round-trip efficiency assumption was used to approximate the pumping and generating efficiency parameters.

C. Distribution System Impacts

This section describes the analysis to evaluate the costs and benefits of distributed generation (DG). Potential benefits of DG include loss savings and deferral of investments in growth-related transmission and distribution infrastructure. Costs include investments required to interconnect DG resources to the distribution system, and any system upgrades needed to reliably support a greater penetration of DG. The following subsections describe, firstly, the challenges to interconnecting large amounts of DG; secondly, the methodologies used to calculate the costs and benefits of each portfolio; and, thirdly, the caveats and results of the analysis.

C.1 Potential Distribution System Issues under High Penetrations of Renewable Distributed Generation

As penetrations of renewable DG increase on the distribution system, several challenges can arise which may require investments in new facilities and equipment. Many of the challenges listed below can be particularly severe when DG is concentrated on one part of a distribution feeder, far from the substation, or connected to rural feeders, which are typically less robust than urban distribution networks. These challenges issues include the following:

- **Backflow:** Traditionally, power flows one way on the grid: from central station power plants on the transmission system to end uses on the distribution system, such as commercial businesses and residential homes. Under this regime, voltages and conductor loadings on feeders are highest closest to the distribution substation. Voltages generally get lower the farther downstream end uses are located from the distribution substations. However high penetrations of DG may reverse the power flow when DG exceeds the instantaneous load of downstream end uses. Relays and fusing designed to protect the system during faults may not trip correctly when backflow is experienced.
- **Power quality and voltage regulation:** Renewable distributed generation, primarily solar PV, is a variable and intermittent resource. Generation from solar PV can fluctuate due to passing clouds and shadows. As a result, at high DG PV penetrations, voltage regulation can be an issue. Maintaining constant voltage is an important part of providing reliable electric service. Voltage fluctuations can damage equipment, particularly sensitive electronics. Distribution networks include a variety of equipment designed to control voltage within a narrow range, including tap changers, voltage regulators, and capacitor banks. Frequent changes in renewable DG output cause voltage fluctuations on feeders. The resulting need for more active control of voltage can produce extra wear on voltage regulation equipment, which can degrade power quality. Furthermore, concentrations of DG on feeders, and backflow, can increase local voltages, causing local over-voltage conditions.
- **Distribution planning for DG, and local current conditions:** Conductors (i.e. distribution wires) may not be capable of handling the extra current (electricity flow) created by distributed generation. Conductors are sized

by the utility to handle a certain amount of expected current. Typically, as part of a DG interconnection study, utilities will evaluate whether the sizes of local conductors are sufficient to handle additional DG, and may require distribution upgrades if the system is not sufficiently robust. However, localized overloads on feeders may occur if interconnecting DG is not adequately studied to identify necessary upgrades, or if load conditions change, e.g. if end uses that were previously using the DG power suddenly leave the system. Furthermore, if DG output on a feeder is unknown, it can mask the load the utility would experience if DG were to trip off, complicating distribution system planning.

+ **Islanding and System Voltage Stability:** For safety reasons (to prevent accidental electrocution), standards for interconnecting DG require that generators disconnect from the system during fault conditions to prevent islanding. Problems on the transmission network, such as voltage droop, which propagate to the distribution system, can cause DG with inverters to disconnect. With high DG penetrations, large amounts of DG could be disconnected from the system simultaneously, causing a large drop in voltage that could further accentuate system-wide voltage instability.

+ **Inflexibility when restoring service or during maintenance:** Service can be restored to customers after a local system fault or during maintenance by reconfiguring the distribution system through opening some circuits and closing others (known as “field switching”). DG may make the system less flexible when reconfiguring the distribution system, affecting power quality or prolonging outages for some customers.

To ensure reliable operation, expansion of DG must be coupled with upgrades to the distribution system that, in some cases, can be costly. As penetration of DG at the feeder level increases, the capability of the existing system to absorb additional DG is used up. Upgrades to the system become more significant and costlier as a distribution network becomes more saturated with DG.

C.1.1 POTENTIAL TECHNOLOGY SOLUTIONS

There are a number of potential solutions to the challenges listed above. In addition to investment in utility system upgrades, the system impacts of interconnecting DG resources can be mitigated to some extent with technology solutions. Such potential “smart grid” solutions to integrating DG are discussed in detail in the DNV KEMA report “Qualitative Investigation of Distribution System Technical Issues and Solutions: Ranking of Distribution Smart Grid Options” found in Appendix F.

C.1.2 MODELING THE NET COST OF DISTRBIUTED GENERATION IN 2030

DG development without regard for the location specific limits of the distribution system could increase interconnection costs significantly. Feeder designs vary by utility and by the type of load served. Each feeder is unique, differing in the amount of DG that can be interconnected at relatively low cost before significant upgrades are required, and the types of upgrades required to interconnect more DG. The total cost of interconnecting large amounts of DG systems will strongly depend on where the systems are installed. As with large scale renewable energy, the policy and procurement decisions will affect the total cost of new resources. Quantifying the potential cost of a future DG build out is subject to uncertainties including:

- The location specific costs of interconnection and system upgrades that are determined by the local system characteristics and the type of technology available.
- The distribution of DG installed at the feeder level; e.g., whether it is concentrated on one feeder or interconnection point, or evenly spread across many feeders and interconnection points.
- The benefits of distributed generation including potentially deferred investments in the distribution and transmission systems, and reduced transmission losses.

In this study we model three DG build out cases as part of the 2030 50% RPS Scenarios. Each DG build out case assumes a different mixture and level of DG uptake of residential rooftop, commercial rooftop, and ground mounted systems. This DG build out is treated as incremental to the assumed level of net energy metered solar PV in 2030 that is common across all scenarios. The three modeled DG build-out cases are described as follows:

Rooftop Solar Scenario:

- Assumes that a large share of future renewable resources used to meet a 50% RPS in 2030 is met with rooftop solar resources.
- Assumes that the uptake of residential systems is greatest in areas of the state with high existing concentrations of rooftop systems.

Small Solar Scenario:

- Assumes that a large share of future renewable resources used to meet a 50% RPS in 2030 is met with small, ground-mounted solar resources.

- Assumes more commercial and ground-mounted systems with better cost and performance characteristics than residential rooftop systems.
- Assumes new policies are put in place before 2030 to target and direct development of distributed generation to help reduce total system costs, including resource costs, as well as transmission and distribution costs.
- Assumes that the larger distributed systems connect at relatively higher voltages or directly to the substation.

All Other Scenarios:

- The 33% RPS, 40% RPS, and 50% RPS Large Solar and Diverse Scenarios all assume 7,000 MW of rooftop PV are installed under current Net Energy Metering polices by 2030 in California.

Table 8 shows the percentage of installed DG capacity by technology type in 2030 for the 50% RPS Rooftop Solar and Small Solar scenarios, including non-RPS NEM solar PV, as well as the solar PV used to meet the RPS.

Table 8: Share of installed DG capacity by category, and percentage of CA households with PV, for Small Solar and Rooftop Solar Scenarios

Scenario	50% RPS Rooftop Solar	50% RPS Small Solar
Residential Roofs below saturation point	40.1%	24.3%
Residential Roofs above saturation point	38.1%	9.3%
Commercial Roofs	6.0%	17.0%
Ground	15.9%	49.4%
Percentage of CA households with PV	32.9%	13.8%

Table 8 also shows that nearly one-third of California households are estimated to have rooftop solar by 2030 under the 50% Rooftop Solar Scenario, and nearly 14% of households are estimated to have rooftop solar under the 50% RPS Small Solar Scenario.

The following sections present the methodology used to estimate distribution system costs, the methodologies used to estimate distribution system benefits, and lastly the results of the analysis.

C.2 Distribution System Costs

This analysis uses a two part methodology to estimate the interconnection and distribution system upgrade costs for each of the 2030 Scenarios in this report. The first step is to estimate DG installations in California by location to reach the megawatt goals in each scenario. The second step is to estimate the costs of interconnecting those megawatts.

C.2.1 ESTIMATING DG INSTALLATIONS BY LOCATION

Residential rooftop and small solar DG uptake rates by 2030 are designed for each scenario as hypothetical "what if" scenarios to address key questions in the study. The future cost of interconnecting these resources depends on where they are installed. Distributed generation installation locations are estimated using a simple set of rules for each type of DG.

C.2.1.1 *Estimating residential rooftop solar installations by location*

We assume residential rooftops will have higher uptake in areas with higher existing concentrations. To account for this, the installed residential rooftop systems by 2030 are scaled up using data regarding the location of the existing set of net energy metered (NEM) systems in 2012. The number of residential rooftop systems by census block group is increased at a rate relative to the existing concentration of NEM systems; adoption is limited to 50% of households in each block group. Figure 18 below shows the existing CSI penetration of residential rooftop systems in red, as a percentage of households in each census block group. The scaled up potential, limited by the 50% household adoption constraint, is shown in blue.

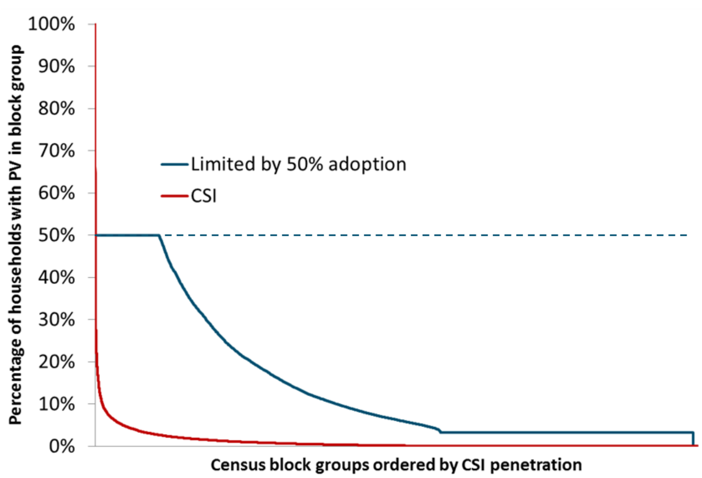

Figure 18: Existing CSI residential rooftop systems and scaled up rooftop systems for Rooftop Solar Scenario

The existing distribution of residential rooftop systems is shown geographically by block group in the figure below. The relative scaling shows census block groups with the highest density per number of households in red, and census block groups with the lowest density in blue. Those with higher densities of existing residential rooftops are assumed to have higher rates of adoption between now and 2030, limited by the maximum uptake by households in each census block group.

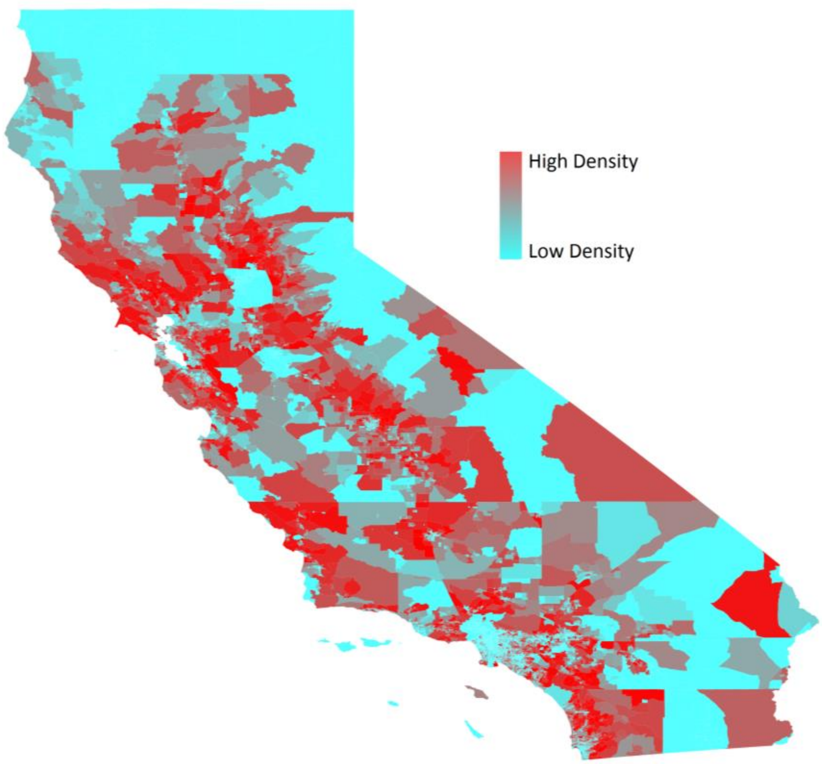

Figure 19: Relative density of residential rooftops in California per number of households by census block group

Assignment of Residential Rooftop PV to Substations

Assignment of the DG projects located in each census block group to nearby substations is important for determining the penetration and saturation of DG at the substation level, and the costs of interconnection. Using detailed feeder topology and precise location information of every forecasted residential rooftop system was not possible for the study, and would have conferred little benefit given the level of uncertainty in projecting out to 2030. Instead we assume that DG in each census block group is assigned to the three nearest substations. We assume the share of DG interconnected to each substation to be inversely proportional to the distance between the centroid of a census block group and each of the three substations. The figure below shows an example assignment of distributed generation within a census block group to three substations. The nearest substation, A, receives 59% of the interconnected megawatts, substation B receives 24%, and substation C receives 17%.

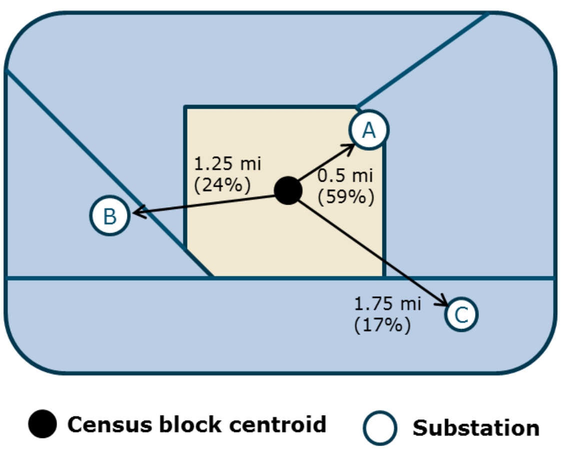

Figure 20: Assignment of DG to substations within a census block

C.2.1.2 Estimating Small Solar Installations by Location

Small solar generation is split into commercial rooftop systems and ground mounted systems in this analysis. Rather than scaling up existing installation patterns through 2030, we assume that future small solar will be installed at sites that result in high solar PV capacity factors. This approximates a future scenario in which the most economically favorable sites for small solar will be developed first. All small solar sites are assumed to connect to a feeder from the nearest substation. Potential commercial rooftop sites are identified using data from the CPUC's 33% RPS Implementation Analysis,[5] where satellite imagery was used to identify potentially solar-compatible commercial roofs. Commercial rooftop solar in the 2030 scenarios is assumed to be limited to 80% of the identified potential rooftop space. Ground sites are identified using data from the Black & Veatch study of ground solar potential for the Renewable Energy Transmission Initiative (RETI)[6]. These sites can accommodate up to 20 MW of PV and have been screened for participation barriers.

C.2.2 ESTIMATING THE COST OF DISTRIBUTED GENERATION INTERCONNECTION

The cost of DG interconnection depends on the penetration of renewables at each substation, and the capacity of that substation to absorb additional DG before major upgrades are triggered. One significant problem in forecasting DG interconnection costs is the degree of variety among feeder and substation

[5] http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/ltpp_history.htm. See B&V and E3 - PV Assessment, June 18, 2010.

[6] See *Renewable Energy Transmission Initiative Phase 1A Final Report*, Black & Veatch, April 2008. http://www.energy.ca.gov/2008publications/RETI-1000-2008-002/RETI-1000-2008-002-F.PDF.

configurations; interconnection costs will vary significantly between feeders, and even between locations on the same feeder. Upgrade costs will, in general, increase as more DG is interconnected. However, the costs will be specific to the feeder and substation configuration, and the installation pattern of DG. A detailed analysis of DG interconnection costs would require an engineering feeder-by-feeder analysis for a geographically specific DG build out scenario, and is beyond the scope of this study.

In lieu of this type of analysis, E3 used a simple methodology to estimate DG interconnection costs, illustrated in Figure 21. It is assumed that some amount of small rooftop PV DG can be interconnected at a low cost up until a saturation point is reached, at which point interconnection costs increase substantially. The saturation point is defined as a fraction of the “no backflow” criterion developed by E3 in a CPUC study.[7] This study applies 70% of the no backflow criterion in urban areas, and 50% of the no backflow in rural areas where distribution systems tend to be less robust. The “no-backflow” criterion de-rate is appropriate because the dataset used in this analysis measures backflow at the substation level, rather than on each individual feeder. Without the de-rating factor this would result in an overestimate of the potential to add DG because localized backflow or overloads may occur on line segments below the substation.

The cost of interconnection is represented by a simple $/kW value derived from utility interconnection studies. The high interconnection portion of the chart is represented by the mean of utility interconnection study cost results for larger

[7] http://www.cpuc.ca.gov/NR/rdonlyres/8A822C08-A56C-4674-A5D2-099E48B41160/0/LDPVPotentialReportMarch2012.pdf, pp 30-38.

ground and commercial systems at a value of $300/kW. Interconnection costs before the saturation point are assumed to be one tenth of this cost at $30/kW.

Small, ground-mounted and commercial rooftop projects are assumed to always trigger distribution system upgrades in this study, thus are always assumed to be above the saturation point shown in Figure 21. All of these systems receive the full $300/kW interconnection cost, represented by the mean of utility interconnection study cost results for these types of systems. Residential rooftop systems are smaller and more dispersed, resulting lower distribution upgrade costs than the ground-mounted systems in the Small Solar Scenario. When many residential rooftop systems are interconnected near a single substation, the penetration of DG can be high enough to reach the saturation point and increase the costs of interconnecting residential rooftop systems.

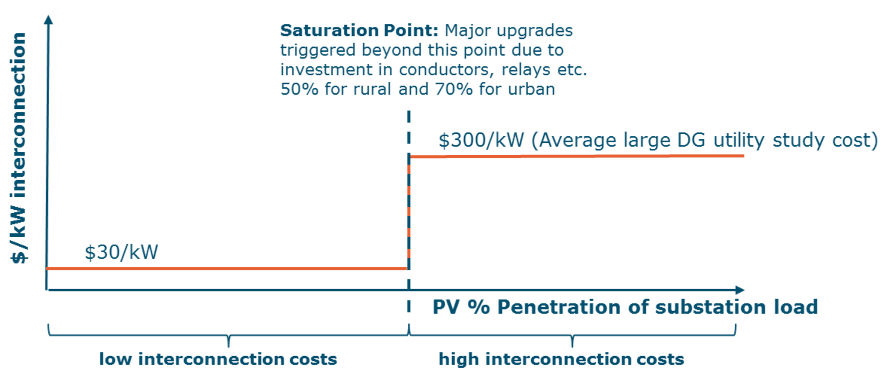

Figure 21: Simple methodology for estimating distribution system costs on a given distribution system substation

C.2.2.1 Defining the saturation point

The type of substation and feeder configuration will determine at what saturation point major upgrades are triggered. The distribution of DG is also an important determinant. Geographically concentrated PV on one section of a feeder, for example, will lower the saturation point by causing localized backflow or overloads on a line segment. In addition, this study uses substation level load data that is not granular enough for feeder specific analysis. Substation load shapes provided by the IOUs, and corresponding simulated PV shapes for 2010, are used for this analysis.[8] Saturation at the substation level will be dependent on the loads experienced by each feeder. The less coincident the loads on each feeder, the lower the saturation point, as a percentage penetration on the substation.

An idealized saturation point is first defined as the maximum amount of DG installation that would not backflow onto the higher voltage distribution system at any time of the year. Distributed generation penetrations above this point would guarantee backflow on feeders below the substation, which we assume would trigger significant distribution system upgrades. This idealized saturation point is then de-rated to reflect more realistic operating condition. A more realistic saturation point will be lower than this “idealized” saturation point if the feeder loads are not coincident, and if residential rooftop PV systems are not perfectly distributed on the feeders. These conditions are, of course, true of all substations, and lead to the development of a de-rated saturation point level.

[8] E3 removed erroneous measurements and assigned and scaled load shapes to substations without data. PV shapes were simulated by Clean Power Research for the year 2010. Details of these methodologies are available in the CPUC Report “Technical Potential for Local Distributed Photovoltaics in California” March 2012. http://www.cpuc.ca.gov/NR/rdonlyres/8A822C08-A56C-4674-A5D2-099E48B41160/0/LDPVPotentialReportMarch2012.pdf

Two “de-rated” saturation points are used in this analysis: one for urban substations, and one for rural substations. The urban and rural saturation points are 70% and 50% of the “idealized” saturation point, respectively, shown in Figure 22 for an example substation.

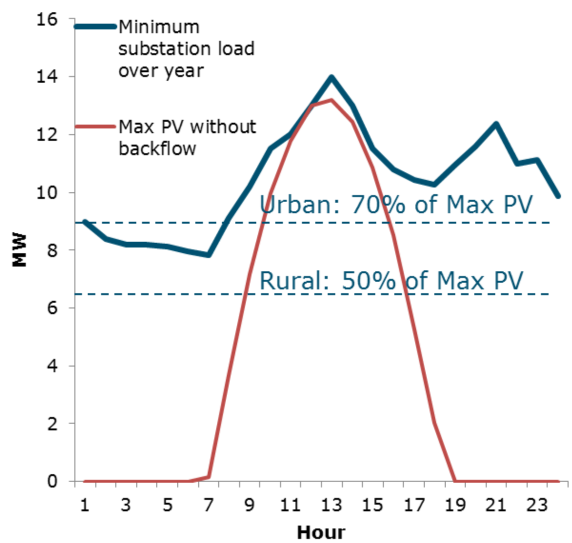

Figure 22: Example substation daily load shape and solar PV generation profile, illustrating the assumed urban and rural saturation points

The assumed urban and rural saturation points are subject to numerous uncertainties, representing average values for substations that vary in greatly between utility and load served. These “rule-of-thumb” numbers are selected as a rough approximation of the effects of imperfect feeder load coincidence and the random distribution of interconnecting DG systems. However they can be considered, at best, ball park numbers.

C.3 Methodology for Estimating Transmission and Distribution System Benefits

In some parts of California, distributed PV may help to defer transmission and distribution system investments and reduce system losses. Reduced system losses are reflected in the revenue requirement calculations in this analysis through reduced generation requirements. Deferred transmission costs from DG are reflected in the scenario cost analysis, reflected as fewer MWh of renewable energy that must be delivered over the transmission system. The distribution and sub-transmission deferral benefits of DG are estimated using an adapted version of the methodology in the 2012 CPUC LDPV Report[9], as described below.

C.3.1 DEFERRED DISTRIBUTION SYSTEM BENEFITS

Distribution avoided costs are calculated using the CPUC LDPV methodology based on data from the IOU capital expansion plans. The benefits of deferring capacity related investments are estimated using project costs by substation and associated load growth forecasts. Figure 23 below shows the potential distribution avoided costs in $/year for 1 kW with 100% capacity factor by substation. Deferrable investments range from $420/kW-yr to $0/kW-yr depending on the substation.

[9] http://www.cpuc.ca.gov/NR/rdonlyres/8A822C08-A56C-4674-A5D2-099E48B41160/0/LDPVPotentialReportMarch2012.pdf See Appendix C.

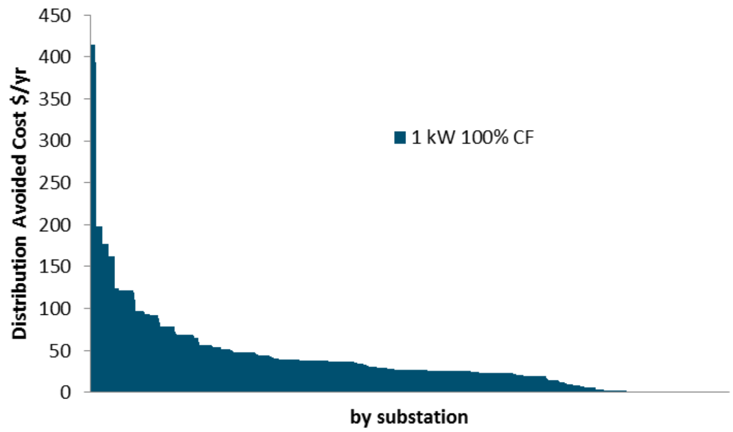

Figure 23: Distribution avoided costs by substation for 1 kW at 100% capacity factor

The distribution benefits for DG projects in this analysis are subject to two factors:

- The coincidence of PV generation with the highest load hours at a substation level, and
- The maximum capacity deferral benefit realizable by PV, as measured by the difference between peak load during the solar producing day and during the night.

The coincidence between PV generation and substation load determines the potential benefit of each additional megawatt of PV installed on the system. Reductions in the substation net peak load are only possible when the net peak load occurs during daylight hours when PV installations are producing energy. Even on daytime peaking substations, the benefit of PV is limited because PV eventually pushes the net peak load hour into the nighttime hours.

These two factors are discussed in the following two sections, followed by a discussion of the caveats to this approach and why realizing these benefits could be difficult.

C.3.1.1 Coincidence of PV Generation with the Substation Load Shape

PV's capacity deferral benefit depends on the coincidence of PV generation with the highest load hours. The peak capacity allocation factor (PCAF) methodology is used to calculate PV's contribution to lowering the load in the highest hours.[10] This is a weighting system that assigns more importance to reducing capacity during high load hours and zero importance to reducing load in hours in which load falls below a threshold. The PCAF weighting in each of the highest hours is multiplied by the corresponding capacity factor of PV in those hours to return an effective load carrying capability (ELCC) for solar at the substation level. The ELCC of PV is multiplied by the substation level distribution avoided cost to estimate the potential benefits of installing PV on the substation.

C.3.1.2 Maximum benefit realizable by PV

The above PCAF methodology calculates the ELCC of the first kilowatt of PV installed at a substation. However the benefits of installing additional kilowatts will decrease as penetration increases. Ideally, to calculate the reduction in ELCC of PV as PV penetration increases, an intensive analysis of the substation net load shape at different PV penetrations would be undertaken. The results would

[10] The highest load hours are defined for each substation based on the PCAF methodology, see Appendix C of 2012 LDPV report. **http://www.cpuc.ca.gov/NR/rdonlyres/8A822C08-A56C-4674-A5D2-099E48B41160/0/LDPVPotentialReportMarch2012.pdf**

show a steadily reducing marginal ELCC, asymptotically approaching a maximum benefit as shown conceptually in the figure below.

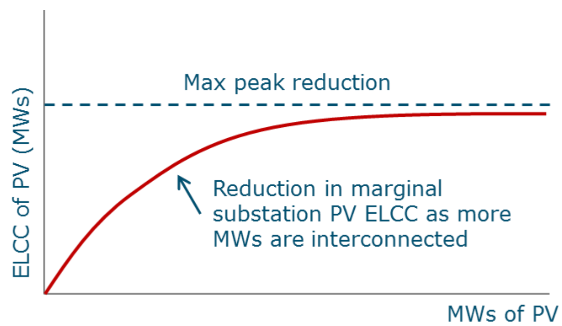

Figure 24: Conceptual illustration of the reduction in ELCC of PV as penetration increases on a given substration

For this analysis, the curve in Figure 24 is approximated in two steps. First, by assuming the difference between the maximum daytime peak during PV production hours and the maximum nighttime peak is equal to the maximum realizable reduction in load due to PV. Figure 25 below shows the maximum peak reduction for an example substation with a daytime peak. Only daytime peaking substations are assumed to benefit from load reduction from PV. Figure 26 shows a different substation with a nighttime peak. In this case, PV does not generate during peak load times and is therefore unable to reduce peak load on nighttime peaking substations. These substations receive no benefits from PV in our analysis and represent 34% of all substations within the California study area.

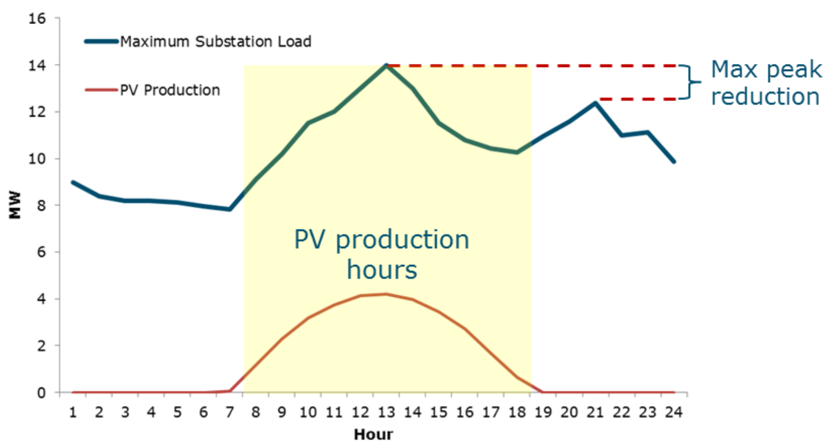

Figure 25: Maximum peak reduction possible from solar PV when substation peak occurs during daylight hours

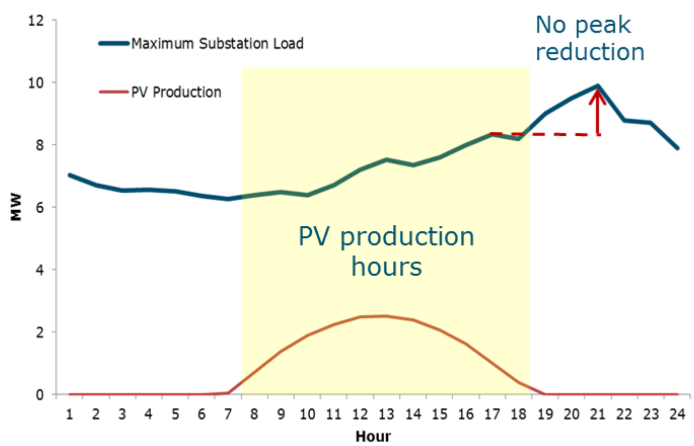

Figure 26: No peak reduction possible from solar PV when substation peak occurs during nighttime hours

The second step to approximating the ELCC curve in Figure 24 above is to use a piecewise linear function. In Figure 24, the gradient of the curve at the origin is equal to the marginal ELCC calculated with the PCAF method. We extend that gradient to hit the maximum peak reduction. The result is a set of substation specific piecewise linear curves that limit the ELCC of PV at the substation level. The Figure 27 illustrates the approximation of the ELCC curve that is used in this analysis.

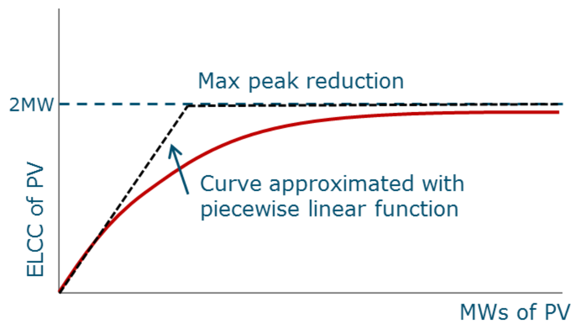

Figure 27: Piecewise linear approximation of decreasing marginal ELCC with penetration

The resulting avoided costs for PV used in this analysis at the distribution level are shown by substation in Figure 28 in orange. The unadjusted distribution benefits are shown in blue, and the effect of adjusting for the coincidence of PV with the highest load hours is shown in gold. With the additional adjustment of limiting substation deferral benefits based on the maximum peak reduction, the avoided costs reduce further. These are shown in orange.

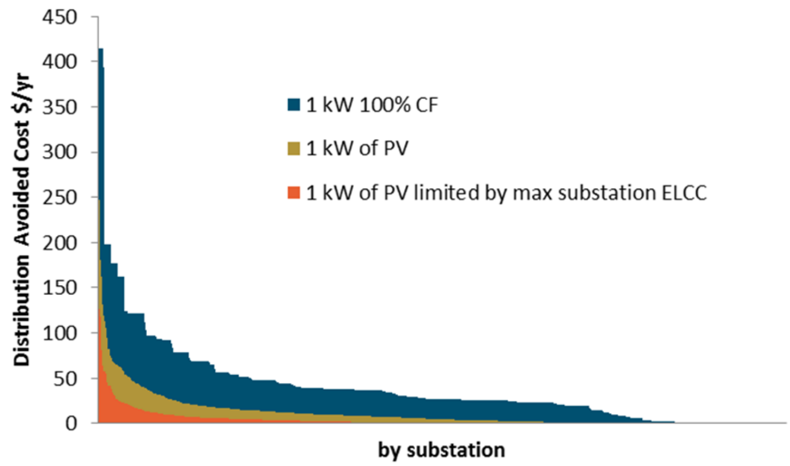

Figure 28: Distribution benefits by substation

C.3.1.3 Caveats to realizing distribution deferral benefits

The simple approach to calculating distribution deferral benefits that is used in this study assumes that a MWh of energy delivered from a DG PV system has comparable dependability to a MWh of energy delivery from a utility-scale power plant over the grid. Further, it assumes that DG systems can be adequately planned for by the utility, and can be incorporated into distribution system planning. However, there are a number of potential challenges associated with realizing distribution benefits from distributed generation. These challenges are summarized below:

+ **Variability and intermittency of DG/lack of geographic diversity:** The output of local PV generation is variable and uncertain. At the transmission and potentially sub-transmission scale, diversity benefits of solar PV spread across a wide geographic region can confer a level of firm capacity from the aggregated PV resources, which can be relied upon in system planning. However, local distribution scale PV resources are typically concentrated within a relatively small geographic region. As a result, local DG systems may not have the level of diversity required to defer a capacity-related distribution investment. For example, DG on a particular feeder may be clustered too closely to provide reliable output in cloudy weather. If the PV generation is not available when the system needs it, this will limit its ability to defer an upgrade on that feeder. The analysis includes a single year of hourly load and PV data at each substation from 2010. This data is used to estimate PV output by substation correlated with load data, however, this single year of data is not sufficient to evaluate a level of firm capacity from local DG PV.

+ **Safety during outages and reliable capacity:** Under current IEEE standards for DG inverters, DG must be disconnected from the grid during abnormal system voltage or frequency conditions such as occur during transmission system faults to avoid unexpected live conductors and potential electrocution. Furthermore, there is a delay before DG can reconnect to the system even after the abnormal conditions are resolved. DG is therefore not available as reliable capacity on a feeder under these conditions.

+ **Distribution system maintenance and reconfiguring:** While the energy from grid-sourced power plants can still be utilized when the distribution system is temporarily reconfigured during maintenance or fault recovery, reconfiguration in the presence of DG systems is less flexible and may require DG to be tripped. This means that the DG generally will not be reliably available to the system during system maintenance and reconfiguring.

+ **Maintenance of DG systems:** In order for distributed generation to defer long-term distribution planning upgrades, it must be reliably available for many years. However, it is unknown as to whether DG systems will be adequately maintained for at least 10-20 years.

Notwithstanding these caveats, renewable DG systems may be capable of offering equivalent dependability to grid-delivered energy if coupled with inverters with sufficient storage and other smart grid functionality, including fault ride through and volt-var control. Reducing backflow and storing PV generation for use during substation or feeder peak load periods are both possible with this technology and could help defer investments in the distribution system. However, there are cost, technology, and implementation barriers to these technologies as well, as discussed in the KEMA report "Qualitative Investigation of Distribution System Technical Issues and Solutions: Ranking of Distribution Smart Grid Options" found in Appendix F.

C.3.2 DEFERRED SUBTRANSMISSION BENEFITS

Deferral of sub-transmission investments may be more easily realizable than distribution investments, due to the greater geographic diversity of the DG downstream of the sub-transmission system. The aggregate DG shape at the sub-transmission level therefore may have more reliable service, and any abnormal system conditions on the distribution system may have less of an impact at the sub-transmission level.

The $/kW-yr sub-transmission avoided costs applied in this study are based on estimates developed for the California Energy Commission's "2013 Time Dependent Valuation of Energy for Development of Building Efficiency

Standards" and for the 2010 CPUC evaluation of Demand Response.[11] The same coincidence and maximum benefit approximations described for distribution deferral benefits in the previous section are applied to the aggregate PV and load shapes at the sub-transmission level to calculate sub-transmission avoided costs.

C.3.3 BENEFITS FROM REDUCED SYSTEM LOSSES AND TRANSMISSION INVESTMENT

Distributed generation reduces losses on the grid and potentially avoids or defers transmission investments otherwise needed for central station renewables. This study assumes energy losses of 3% on the transmission system and 4.9% on the distribution and sub-transmission system (California Energy Commission, Integrated Energy Policy Report). Less energy must therefore be produced by DG sources than central station for the same level of delivered energy. However, with significant penetrations of DG, some energy is expected to flow back onto the transmission system, particularly from rural sites, where loads are low relative to DG production. Energy from DG flowing onto the transmission system does not avoid transmission losses or generate avoided transmission benefits. Energy from DG that does not flow onto the transmission system is assumed to be utilized at the distribution level and avoid transmission investment costs associated with large scale renewable development.

Quantifying the flow of energy back on to the transmission system from DG resources would require detailed power flow models of the distribution and

[11] For more details, refer to Appendix C of 2012 LDPV report. http://www.cpuc.ca.gov/NR/rdonlyres/8A822C08-A56C-4674-A5D2-099E48B41160/0/LDPVPotentialReportMarch2012.pdf

transmission system which is beyond the scope of this analysis. Flows would be heavily dependent on uncertain factors such as the distribution and transmission topology in 2030, the placement of resources on the system including the location of DG in relation to the transmission topology, and local load in 2030 across the state. As a simplifying assumption in the absence of more information, in this study 50% of all DG energy is assumed to back-flow at the substation level onto the transmission system. The remaining 50% is assumed to be absorbed by the distribution system. To calculate the assumed energy back-flow at the substation level, we compare each hour of the aggregate solar shape of installed resources at each substation with the corresponding substation load shape. The excess energy is assumed to back-flow onto the transmission system. The resulting differences in total installed MWs by scenario are accounted for in the Scenario resource portfolio costs.

C.4 Results of Benefits and Cost Analysis

Table 9 below shows the total per megawatt hour cost of interconnection and distribution system upgrades estimated for DG under the 2030 50% RPS Rooftop Solar and Small Solar Scenarios. The table shows the total cost of DG systems in 2030 and the component pieces including interconnection and upgrade costs, avoided distribution and transmission costs, and the average DG power purchase agreement (PPA) cost. While the Rooftop Solar Scenario realizes higher average distribution avoided and sub-transmission benefits, and lower interconnection and upgrade costs than the Small Solar Scenario, the cost of the PV systems themselves combined with the lower capacity factors relative to ground-mounted systems causes the total DG cost to be significantly higher under the Rooftop Solar Scenario.

Table 9: Average, per-MWh cost of DG PV including cost of PV systems, sub-transmission and distribution (2012 dollars)

Scenario	Interconnection and Upgrade Costs ($/MWh) Rooftop Solar Scenario	Small Solar Scenario
Residential Roofs below saturation point	2.38	2.39
Residential Roofs above saturation point	24.05	23.93
Commercial Roofs	22.95	23.22
Ground	20.86	22.30
Weighted Average Interconnection and Upgrade Cost	14.91	17.96
Weighted Average Distribution Avoided Cost	(3.16)	(2.68)
Weighted Average Sub-Transmission Avoided Cost	(2.35)	(2.32)
Net Interconnection and Upgrade Cost	9.40	12.96
	Resource Costs ($/MWh)	
Average DG PPA Cost	192.76	115.46
Average Total DG Cost	202.15	128.42

The avoided distribution and sub-transmission system benefits, distribution interconnection and upgrade costs and transmission costs for each Scenario are shown in Table 10 below. The combined effect of these "wires" costs is shown in the final column of Table 10. On a "wires" basis, among the 50% RPS Scenarios, the Diverse Scenario shows the largest revenue requirement cost impact, followed by the Large Solar scenario and the Small Solar Scenario. The Rooftop Solar Scenario has the lowest estimated combined "wires" cost, despite having the highest estimated total cost.

Table 10: 2030 distribution and transmission cost impacts of each scenario (annual revenue requirement, 2012 $ millions)

Scenario	Distribution and Sub-Transmission Avoided Costs ($M/yr)*	Distribution Interconnection and Upgrades ($M/yr)*	RPS Transmission Costs (incremental to 33% RPS by 2020, $M/yr)	Total ($M/yr)
33% RPS	(167)	257	406	496
40% RPS	(189)	321	955	1086
50% RPS Large Solar	(210)	413	1740	1942
50% RPS Diverse	(210)	413	1836	2038
50% RPS Small Solar	(234)	840	1345	1951
50% RPS Rooftop Solar	(258)	697	1237	1677

*Includes behind the meter net-energy metered projects

D. 2030 Revenue Requirement Methodology

Category	Description	Methodology/Source
Transmission		
Existing Transmission Fixed Costs	Fixed costs of existing transmission assets	The 2012 revenue requirement for this category is used to develop a 2030 forecast based on an assumed real annual escalation rate of 3.8% (the load-weighted average of escalation rate assumptions from each of the utilities in the study).
Planned Transmission Fixed Costs	Fixed costs associated with planned transmission lines identified in the CAISO Transmission Plan.	The 2030 revenue requirement of reliability upgrades and transmission driven by renewable need from the 2010 Long-Term Procurement Plan (LTPP) is used.
High RPS Additional Transmission Fixed Costs	Fixed costs of new transmission lines identified as necessary for scenario-specific renewable portfolios under 40% and 50% RPS scenarios.	The following transmission costs adders (expressed in dollars per MWh of delivered energy) were applied to estimate incremental high RPS-driven transmission costs: (a) $34/MWh for both in-state, central station renewables and distributed renewable generation expected to backflow onto the transmission system; and (b) $46/MWh for out-of-state, central station renewables (See main report for details).
Distribution		
Existing and Future Distribution	Fixed costs of existing distribution system	The 2012 revenue requirement for this category is used to develop a

Category	Description	Methodology/Source
System Fixed Costs	assets, as well as costs related to expected future investments in the distribution system to meet load growth.	2030 forecast based on an assumed real annual escalation rate of 2.6% (the load-weighted average of escalation rate assumptions from each of the utilities in the study).
Incremental Scenario-specific Distribution Costs	The net cost of (1) distribution system upgrades required to integrate high penetrations of renewable DG; and (2) distribution savings for distribution system investment that is deferred or avoided due to renewable DG.	Costs were estimated as part of E3's Distribution Generation Impact Analysis (see Appendix C for details).
Conventional Generation		
Existing Utility-owned Generation and Long-Term Contract Fixed Costs	Fixed costs related to existing utility-owned generating assets and long-term contracts active in 2030. All fixed costs associated with existing coal assets (which are assumed to be retired), qualifying facilities (QF), and Department of Water Resources (DWR) contracts are excluded.	The 2012 revenue requirement for this category is used to develop a 2030 forecast based on an assumed real annual escalation rate of 1.9% (the load-weighted average of escalation rate assumptions from each of the utilities in the study).
New Conventional Generation Fixed Costs	Fixed costs of new conventional generating resources specified by utilities, including local capacity resources necessary to maintain local reliability.	The following levelized fixed costs were used to estimate the fixed costs of new conventional generating resources: (a) $220/kW-yr for combined cycle gas turbine (CCGT); and (b) $217/kW-yr for aeroderivative combustion turbine (CT). (See main report for details).
Resource Adequacy (RA) Fixed Costs	Fixed costs of meeting the Study Area's net resource adequacy (RA) requirement with generic capacity contracts.	The total RA requirement is the Study Area's net peak load times the required planning reserve margin of 115%. The net RA requirement is the difference between the total RA requirement and total utility-

Category	Description	Methodology/Source
		owned and contracted resources. Generic capacity contracts are priced at the levelized fixed cost of a frame combustion turbine ($160/kW-yr), which serves as a proxy for the long-run cost of capacity.
Variable Costs of Energy	Variable costs of generating resources, including fuel costs, variable O&M costs, startup costs and net import costs.	This is a result of REFLEX production simulation runs.
Renewable Generation		
Common Resource Procurement Costs	The direct resource costs of existing and planned future procurement by the utilities to meet 33% RPS in 2020.	The sum of utility-provided total expected direct procurement costs of all renewable contracts active in 2030.
Scenario-specific Procurement Costs	The direct resource costs of meeting each scenario's renewable net short.	The installation vintages of incremental renewable energy are evenly divided between the years of 2016 – 2030. Procurement costs were estimated using the renewable costs detailed in the main report.
Greenhouse Gas Costs		
Compliance Costs	The total cost of fossil generators purchasing California Carbon Allowances.	Greenhouse gas compliance costs are estimated by multiplying the total quantity of greenhouse gas emissions emitted by the electric sector in order to serve load times the price of a CO2 allowance.
Miscellaneous/Other Costs		
DSM/Customer Program Costs	All utility costs of funding demand-side (e.g. energy efficiency, DR, customer solar) and	The 2012 revenue requirement for this category is used to develop a 2030 forecast based on an assumed real annual escalation rate of 0.0%

Category	Description	Methodology/Source
	other customer programs (e.g. CARE)	(the load-weighted average of escalation rate assumptions from each of the utilities in the study).
Other Costs	Any other costs not included in one of the above categories (e.g. regulatory fees, nuclear decommissioning, RD&D, etc.).	The 2012 revenue requirement for this category is used to develop a 2030 forecast based on an assumed real annual escalation rate of 0.05% (the load-weighted average of escalation rate assumptions from each of the utilities in the study).

E.ProMaxLT Model Description

ProMaxLT™

Long-Term Energy –
Transmission Reliability
& Market Simulation

SOFTWARE DESCRIPTION

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1 ProMaxLT™ – Executive Summary

ECCO International, Inc., ("ECCO") has developed and implemented a comprehensive long-term reliability and market simulation package, called ProMaxLT™, to assist Regulators, TSOs/ISOs and Market Participants in understanding the complexities of the competitive electricity market and perform accurate simulations of market behavior and reliability studies for a multitude of applications. The many features incorporated into the standard design of ProMaxLT™ makes it, we believe, the best value-for-money product available.

ProMaxLT™ has been successfully used by various Market Participants as a reliability, market analysis and forecasting tool for long term applications.

The ProMaxLT™ software consists of two platforms; one for energy and transmission market simulations and one for reliability and flexibility analysis. This document presents the complete capabilities of the ProMaxLT™ software market platform.

Typical ProMaxLT™ market applications include:

- Renewable Energy Resources market analysis and integration into the transmission grid
- Flexibility Assessment
- Integrated Plant Expansion plan, where multiple plant expansion options are considered, automatically selecting the best set of options via dynamic programming
- Energy market simulation studies, market price forecasting, etc.
- Transmission congestion forecasting
- FTR/CRR (Congestion Revenue Rights) strategic evaluation and analysis
- Transmission flow analysis and forecasting
- Transmission loss factor analysis and forecasting
- Generation plant revenue and profit forecasting, investment evaluation
- Generator bid strategy evaluation.

The major strength of ProMaxLT™ is the precision of the model which ensures consistency of results between studies and this precision has been proven over again in many market study audit situations, where the results of ProMaxLT™ have been independently checked. This precision and consistency is a result of ProMaxLT™ using a **nodal configuration** which optimizes network flows (and constraints) with dynamically calculated limits using an AC or DC power flow; sequential Monte-Carlo based plant outage consideration; Mixed Integer Programming (MIP) for Unit Commitment, LP-based optimization for dispatch; and discrete hourly modeling. ProMaxLT™ can also be configured to simulate energy markets with zonal configuration where a detailed power flow model is not part of the market clearing.

The major blocks of ProMaxLT™ are shown below in Figure 1.

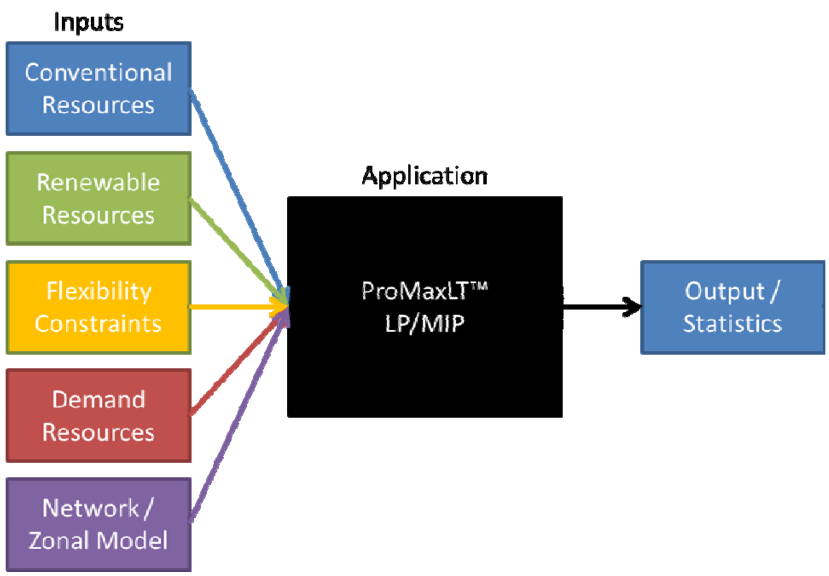

Figure 1 ProMaxLT Configuration

ProMaxLT™ may also be used to perform sensitivity studies of different plant expansion options, fuel price scenarios, load forecasts and transmission expansion options. These sensitivity studies may be used in investment risk analysis and evaluation.

Additionally, ProMaxLT™ can be configured with an optional module to answer questions such as; How many MW of dispatchable resources are needed to meet load and to simultaneously meet flexibility requirements on several time scales? What is the optimal mix of new resources, given the characteristics of the existing fleet? What capacity of RES resources can be added without causing flexibility problems with the existing mix of thermal and hydro plants?

These questions will be addressed in detail in subsequent sections.

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2 Introduction

ECCO International, Inc., ("ECCO") has developed and implemented a comprehensive long-term reliability and market simulation package, called ProMaxLT™, to assist regulators, TSOs/ISOs and Market Participants in understanding the complexities of the competitive electricity market and provide accurate simulations of reliability and market behavior for a multitude of applications. The many features incorporated into the standard design of ProMaxLT™ makes it, we believe, the best value-for money product available. The strengths of our product stem from the following three key attributes:

- **Comprehensive Accurate Database:** ECCO has implemented the facilities necessary for data collection and validation to establish a database to support the calculation and forecast of MCPs/LMPs and reliability statistics including LOLE and EUE, etc. The database also includes the full unreduced network model with proper limits, generation with accurate price profiles and scheduling point price forecasts. Aggregation of nodes to area/zones is also possible. Existing zones can be easily integrated and new zones can be defined based on various criteria, such as LMP price formations. NERC GADS data is used to set the full and partial forced outage rates. These models can be benchmarked against actual operating scenarios to verify outage profiles, prices and instances of congestion.
- **Precision:** ECCO has implemented a full unreduced nodal configuration which optimizes network flows (and constraints) with dynamically calculated limits using an AC or DC power flow; contingency constraints "on the fly" are also modeled; a sequential Monte-Carlo based full or partial plant outage is deployed for reliability analysis; the most advanced Mixed Integer Programming (MIP) formulation for Unit Commitment and/or LP-based optimization for dispatch is deployed for the scheduling/dispatch module; and discrete hourly modeling is used for chronological analysis. This precision will be of considerable benefit in the delivery of best reliability analysis and market forecasts relevant to system's assets. Forecasts can focus on averages, and or volatilities, and sensitivity studies may be readily performed to provide an accurate risk profile.
- **Configurability/Versatility**: ProMaxLT™ uses a robust ODBC database storage mechanism for all input data and output data created. The algorithm we have developed is applicable under different reliability scenarios and market conditions. You can apply ProMaxLT™ to the delivery of forecasts under a wide range of different reliability and market assumptions and scenarios. Output results can be obtained at any level of granularity. Results may be readily formatted into graphical and tabular reports using standard software packages such as Excel and Access.

3 ProMaxLT™

Delivering Precision

In the development of ProMaxLT™, several key features have been included in order to provide you confidence in the precision of the reliability and market forecasts generated. Several of these are explained in the following pages.

Discrete Hourly Modeling Capability

Electricity demand varies on the basis of:

- Time of day;
- Day of week;
- Month of year; and
- From one year to the next.

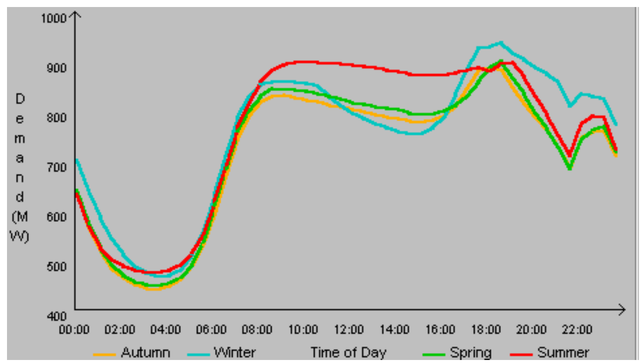


Figure 2– Seasonal Demand Curves

Because of this variation, reliability analysis must be executed on a time-sequential basis.

The same is true for the clearing of the competitive electricity market. During peak-times, the higher priced generators will be dispatched to meet demand – hence, price volatility can be experienced from one hourly period to the next, by virtue of these changes in demand.

Capturing extreme events for reliability purposes and the associated volatility is very important.

- Extreme events and high prices spread over a small % of time and can have a big impact on average outcomes;
- The volatility will also impact the risk position (based on how energy purchase/sales requirements vary over time).

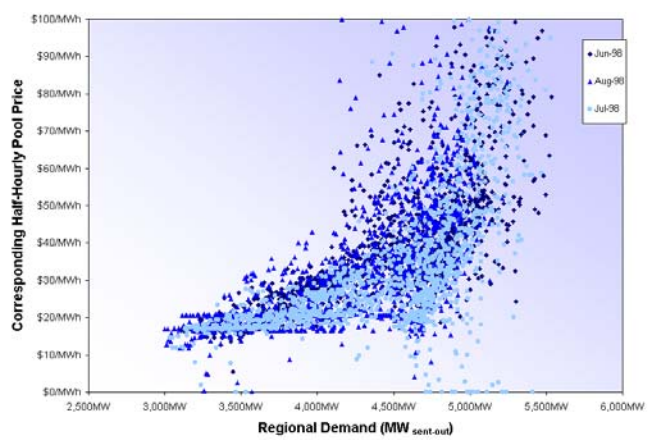


Figure 3 – Scatter graph

It stands to reason that, given that the reliability analysis requires capturing extreme events and the real market exhibits such volatility on an hourly basis, reliability and market analysis studies should also operate on this basis. ProMaxLT™ incorporates as a standard feature the consideration of all 8,760 discrete hourly periods in any given year. This means that the results delivered to you will display true reflection of the natural randomness in prediction of key reliability indices (EUE, LOLP, etc.) and market variables (prices, production volumes and network transfers, etc.).

This, in turn, means greater precision of the results.

4 LP/MIP-based optimization

The electricity spot market is dispatched many times during a given day, week and year to maintain the security and reliability of the power system. The actual dispatch is performed using a complex optimization process that can only be solved (with confidence in the results) through the consideration of a large number of independent and interdependent sets of constraint equations. These constraint equations relate to a wide range of physical and commercial parameters within the market. The optimization solver is usually based on a Linear Programming (LP) or a Mixed Integer Programming (MIP) formulation. Both have been implemented in the ProMaxLT™ software platform.

Over the past 20 years, Linear Programming (LP) has emerged to be the most tried, tested and trusted mechanism by which such complex, sparse-matrix problems can be solved. A diagram representing the spot market operation is provided in Figure 4.

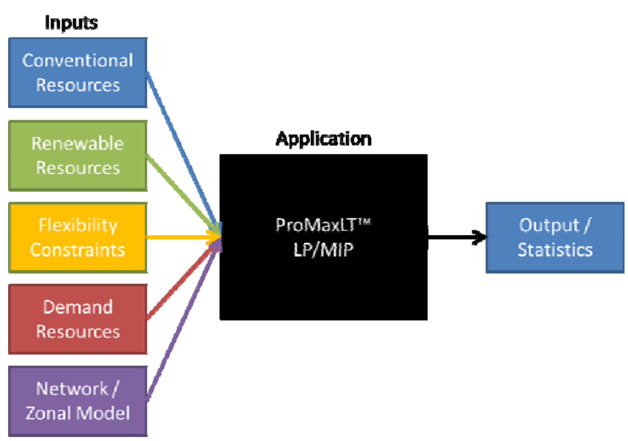


Figure 4 – Inputs and Process

LP-engines can be used in all situations where all inputs can be written in the form of linear equations. For the electricity market, this means that they can be applied in all cases except where full AC load flow modeling is assumed. In the case of a full AC load flow, the non-linear equations are linearized and iterations are performed till convergence is achieved.

ProMaxLT™ includes a sophisticated LP engine for nodal analysis and LMP pricing. It can model any time period from a single time period to typically 30 years ahead at hourly intervals. Annual simulations are generally run for 50 to 1000 simulation years per year of the study to ensure price and production convergence. Multiple iterations of the Monte-Carlo (complete with LP optimization) are performed to provide the added benefit of true convergence to the most likely outcome (in terms of averages, totals and volatilities).

To take into account Unit Commitment constraints, such as start-up costs, ramps, minimum up constraints and minimum down constraints, ProMaxLT™ also includes an advanced MIP-based Unit Commitment solver to clear the market and perform nodal/zonal analysis and LMP/zonal pricing. The Unit Commitment software iterates with a full AC load flow model to model losses and compute prices that reflect the cost of losses in addition to the cost of energy and the cost of congestion. The modeling of the MIP/LP solver coupled with a full network model provides for the most accurate and robust analysis possible. This modeling allows the user substantial flexibility to aggregate the reliability and market results to any desired level.

ProMaxLT™ is configured to optimize many hourly time periods one-after-the-other, whereas most other similar software are focused in optimizing the next immediate five-minute dispatch period. It is structured such that LP/MIP iterates several times within each hour to take into consideration:

a) Base and contingency constraints,
b) System ancillary reserve requirements for various types of reserves,
c) Dynamic limit equations, and
d) Dynamic inter-regional loss equations.

The outcome of the constrained LP/MIP solution for each time period provides the LMP/zonal prices, together with all line flows and generator outputs. The LMP/zonal prices are calculated from the LP dual variables of the bus equality constraints. For large case studies, the ProMaxLT™ execution is managed by MySQL server and is parallel processed on several dual core machines as described above. The price in a given time interval (e.g., an hour) is an outcome of the application of the market rules to the simulated market clearing dispatch. Also the generation is dispatched in order to meet a security constrained dispatch. This detailed integrated approach provides a more realistic forecast of the LMP/zonal prices because it allows evaluation of the system under a variety of unit-forced outage scenarios. It truly captures the effects of congestion on marginal prices and provides a realistic LMP/zonal price forecast that can be used to assess the potential revenue from various hedging plans.

The model can also be calibrated against historical LMP/zonal price levels. The calibration process usually works as follows. LMP/zonal price duration curves are built using actual, historical LMP/zonal prices. These duration curves are compared with LMP/zonal duration curves calculated by ProMaxLT™. Differences between the two distributions are analyzed and assumptions are validated. In this process we focus on historical bidding patterns, tie flows, loads, network model, limits, hydro profiles, and generation outages. Actual and forecast data are compared on a statistical basis with ease (see first diagram below), since backcasted and forecasted data is collected and processed in the same data format. Modifications of this data are made, if necessary, to achieve the best calibration results. The calibrated model based on historical data will result in the same distribution of prices as that of the "real" world. The calibrated model can now be used for statistical analysis of LMP/zonal prices for future studies.

However, where calibration is not feasible (i.e., market and LMP/zonal actual prices do not exist), the network is modeled from the bottom up (load, generation, transmission) and does not need to be calibrated. The model can provide any level of modeling detail from a single area, single price to a regional or full nodal model.

Once LMP/zonal prices are available, ProMaxLT™ will provide the capability to execute queries and produce for each location LMP/zonal probability distribution functions, LMP/zonal cumulative distribution functions, and LMP/zonal duration curves. This wide range of statistical data on future LMP/zonal prices for each location is provided as part of the standard output of the ProMaxLT™.

5 Full Monte-Carlo Based Outage Modeling for Market Studies

The ProMaxLT™ market platform exactly mimics the clearing of the ISO/RTO energy market clearing. It offers the ability to accurately model the detailed transmission network and provides additional flexibility to the user to focus the analysis at any level of granularity and network configuration. A sequential Monte-Carlo simulation engine is available to model uncertain variables, such as outages. All generation units in the market will periodically experience outages, which will remove them temporarily from service. These outages may be the result of any of a number of phenomena:

- Planned full and partial maintenance outages;
- Forced outages (due to plant breakdown);
- Partial forced outages
- Forced outages (due to other issues, including fuel supply disruptions and industrial relations disputes).

Under the previous, centrally planned industry regime, complex statistical parameters were developed in order to describe such outages. These could then be applied to forecasting to allow consideration of the impact of plant outage. Various techniques were developed. The most advanced of these was based on (Monte-Carlo based) randomization of unit outages. This technique delivers a true reflection of the natural randomness that occurs in relation to these events and hence delivers a more precise forecast.

ProMaxLT™ is stochastic in nature; it uses a Monte-Carlo random outage scheduler to create full and partial outage states for both generation and transmission. Maintenance and forced outages are prepared from the best available data in each market. The Monte-Carlo forced outage event modeling in ProMaxLT™ allows the true impact of multiple coincidence outages to be forecasted across multiple iteration of the same scenario. ProMaxLT™ has the capability to represent a unit by a two-state Markov model or a three-state Markov model. The two-state model assumes that a unit may reside in one of the two mutually exclusive states (success, failure). The unit transitions between these two states. The three-state model assumes that a unit may reside in one of the three mutually exclusive states (success, partial failure or de-rated state, failure).

The Monte-Carlo facility in the ProMaxLT™ software market platform is similar to the one deployed by the ProMaxLT™ software reliability platform. It can deploy seasonal EFORs as well as dependencies between outages using conditional probabilities. Seasonal incident rates are used in random draws to determine if an outage occurs in a specific simulated day; seasonal mean and sigma for the duration of the outage in random draws determine the end day of the outage. These seasonal values used in the random draws are weighted by the relative position of the simulated day with respect to the mid-points of the seasons.

Furthermore, ProMaxLT™ models dependencies between outages. For example, consider a set of two identical generators with dependent outage probabilities. Assuming that both units are available at the start of the simulation, the forced outage on each unit can be simulated using random draws based on the probability of forced outages. However, when one of them is outaged during the course of the simulation, the probability of outage of the second unit will be increased to the conditional probability of forced outage of the second unit given that the first unit is forced out. The values of the individual outage probabilities and the conditional probabilities can be selected based on historical data for the units or expert judgment based on system-wide occurrences of correlated forced outages.

ProMaxLT™ also contains specialized techniques for simulating the random behavior of demand typically seen in chronological hourly forecasts (e.g. load, wind energy, etc.) without unduly affecting their typical (daily or seasonal) profiles. This modeling provides a more realistic assessment of reliability indices. Load forecast uncertainties due to weather are modeled in ProMaxLT™ by running Monte Carlo simulation for various load scenarios. Several load scenarios can be modeled along with associated probabilities which are based on historical data for each target year to be simulated. These probabilities can be modified based on data such as monthly averages of mean, high and low temperatures.

ProMaxLT™ also models intermittent resources using a time of day based capacity factor. The wind category class average factor is usually based on average performance of existing intermittent generators over pre-defined period. If load and renewable generation data is synchronized the analysis is performed based on the net load profiles. The analysis includes growth, seasonal and random components. ProMaxLT™ modifies the deterministic projection by the random component to capture random changes due to stormy weather and/or local wind variations while simultaneously preserving the mean and standard deviation of hourly wind generation as well as the seasonal and daily variations.

For capacity evaluation studies the Effective Load Carrying Capability (ELCC) of renewable resources is deployed which indicates the percentage of the total nameplate capacity that can be counted towards the calculation of the reserve margin. ProMaxLT™ evaluates the ELCC for the system and every defined zone in the system.

A Weibull Distribution is used to randomly determine the outage and repair times for each unit. Using a computer generated seed, the random number generator is used to randomly generate a number between zero and one and the Weibull distribution is then used to convert the number to an outage and repair time for each unit. Four Weibull Distributions are used: a) Full Time to Failure, b) Full Time to Repair, c) Partial Time to Failure, and d) Partial Time to Repair. As a result of this process the simulated failure and repair patterns are determined.

Separate random number generators are used for all generator and transmission elements. This ensures that outage sequences of all plants are independent. All random number sequences are chosen to be dependent of the single seed which is independent of the time clock. In that way, if the same seed is used in a repeated simulation at another time, the study can be reproduced exactly. The reference time for each unit is chosen to be at a fixed reference time in the past, so that multiple runs with different input parameters may be performed with the same outage sequence. This is an important requirement for sensitivity runs.

The Weibull Parameters are determined from long-term historical outage statistics. An example of the Weibull distributions is shown in the figures 5 and 6:

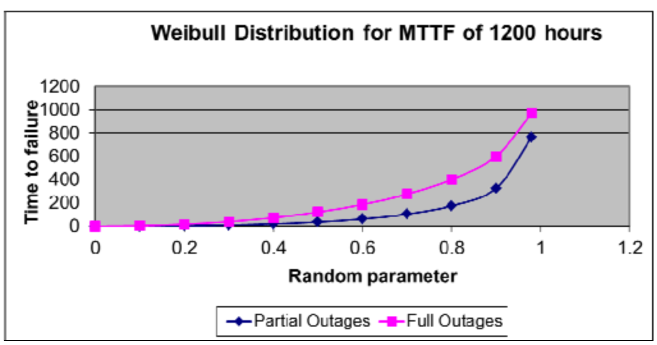


Figure 5 - Sample Weibull Distribution for Unit Failure Time

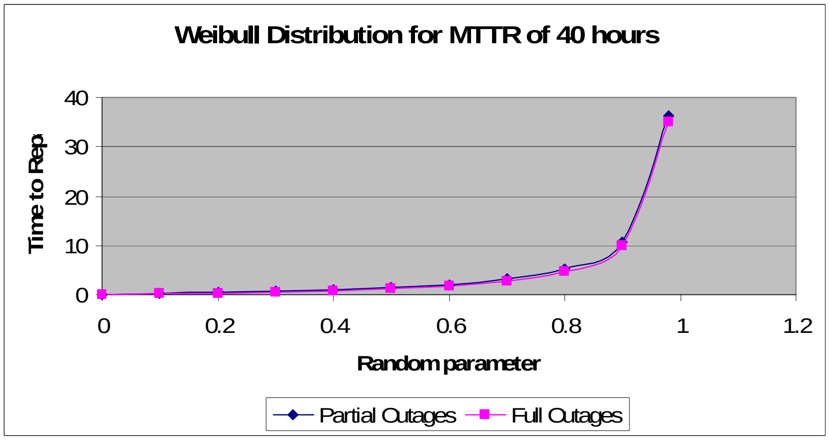


Figure 6 - Sample Weibull Distribution for Unit Repair Time

ProMaxLT™ is capable of incorporating an accurate transmission model with a nodal configuration which optimizes network flows and constraints with dynamically calculated limits on an hourly basis. The model is built bottom up, with every generating unit modeled in terms of its capacity, bidding pattern, maintenance plans and forced outage rates. Every transmission line or group of lines is modeled in terms of its electrical properties (particularly reactance for dc load flow modeling), and transmission limits. Specifically the software reads the susceptance matrix of the network from a power flow solution file and converts the susceptance matrix into LP constraint equations. The power flow equations are explicitly modeled in the MIP/LP solution using shift factors to represent the relationship between line flows and generation output. The bidirectional line limits on each line are also read into the database and converted to constraint equations. The load is modeled on an hourly basis through the year(s), based on reading in historical load curves and scaling for peak load and energy growth rates.

Contingency constraints are also explicitly represented by adding additional constraints that express the flow in the constrained lines as a set of linear shift factors of the generation output levels. These shift factors for the contingency constraints are derived directly from the network admittance matrix with the outages as specified by the contingency set incorporated into the study case.

Furthermore, the market rules are also read into the model. Even though the data preparation will be completely automated, the development of a valid solution, especially for a large number of nodes, will require an extensive level of data checking. Maintenance and forced outages are prepared from the best available data with NERC GADS data as the default. The forced outage event modeling in ProMax™ allows the true impact of multiple coincidence outages to be forecasted across multiple iteration of the same scenario.

6 Detailed Nodal Configuration

We have already outlined how the use of LP/MIP-based optimization can deliver greater precision. Special notice is made here of the use of the MIP/LP-engine within ProMaxLT™ to take account of *(both intra-regional and inter-regional)* transmission constraints.

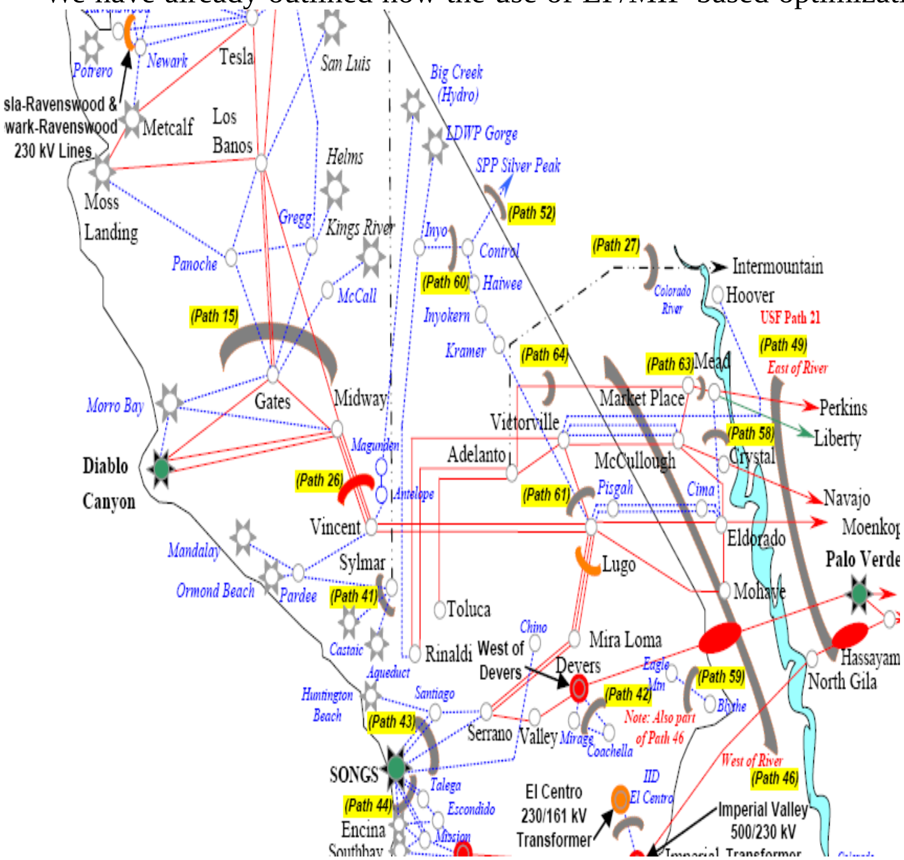


Figure 7 – Nodal Map

When transmission constraints occur, suppliers on the upstream side of the constraint simply can't get their power to market. Not only does this have a big impact on their business, transmission constraints also have a big impact on the reliability and the daily operation of the market as a whole.

A precise model for reliability and market studies must have, as one series of inputs, constraint limitations on links between major supply and demand centers (or nodes). These links will occur **both within regions and between regions.**

The incidence of and impacts due to transmission constraints can be very significant. With dynamically calculated transmission limits and meshed transmission system flows evaluated ProMaxLT™ produces a high level of detail in the forecasts results.

In ProMaxLT™ we provide the facility to precisely consider the impact of transmission constraints between all the nodes we have defined. This will be significant in your consideration of the merits of the reliability results and the range of different investment or operational strategies.

7 Flexibility

The high penetration of RES resources has created a new set of market and operational problems that require immediate attention. The following issues are at the center of the current debate. How many MW of dispatchable resources are needed to meet load and to simultaneously meet flexibility requirements on several time scales? What is the optimal mix of new resources, given the characteristics of the existing fleet? What capacity of RES resources can be added without causing flexibility problems with the existing mix of thermal and hydro plants?

ECCO's ProMaxLT™ platform is taking long-term planning studies to new levels of usefulness and relevancy. The previous generation of LOLP tools determined the Loss-of-Load Probability (LOLP) and related metrics and established the probability that resources will be adequate to meet peak loads. These studies have been conducted to calculate target reserve margins or to determine least-cost expansion plans.

Crucial limitations, however, have been missed or left unidentified with the previous generation of Monte-Carlo based reliability modeling formulations in the presence of high penetration of RES resources.

These tools ignore operational constraints, such as unit ramping capabilities and commitment limitations. The result can be a set of resources that are acceptable from a capacity perspective, but deficient in terms of "flexibility" to meet the variability of the system demand. Increasing levels of RES resources continue to increase the need for sufficient "flexible" resources, which can meet real-time energy and reserve requirements.

In joint development with Energy and Environmental Economics, Inc. (E3), ECCO has introduced the latest generation of System Reliability and Renewable Integration software capability, called, ProMaxLT™ ReFLEX. This application can answer a new class of questions and address a new set of problems arising from the rapid penetration of RES resources into the grid:

1. How many MW of dispatchable resources do we need to meet the system demand, as well as ramping requirements imposed by RES resources on various time scales?
2. What is the optimal mix of new resources, given the characteristics of the existing fleet? In other words: fast, expensive resources or cheaper, slower ones.
3. Can it be more cost efficient to curtail renewable energy, rather than to commit additional flexible resources?

4. Are there more effective solutions to enhancing long-term reliability, besides constructing more generating resources? Potential alternatives include energy storage, demand response, improved forecasting, and changes to ramp & reserve policies.
5. How often do flexibility shortages occur and in what timeframes? Which loads are being impacted the most? Which generator outages are triggering these issues in the transmission system?

ReFLEX for ProMaxLT™ has been developed to address these modeling deficiencies in long-term reliability studies. ProMaxLT™ utilizes sequential Monte-Carlo simulations of relevant probabilistic variables related to supply (e.g. forced outages, load forecast errors, renewable energy forecast errors) as well as realistic models of generators, loads, renewable energy sources, and the detailed transmission system and related limits. Simulation results include loss-of-load events (LOLEV), expected un-served energy (EUE), effective load carrying capacity (ELCC) of wind generators, as well as the specific transmission constraints that result in load-shedding events.

ProMaxLT™ ReFLEX modeling includes:

- Modeling of Conventional Resources
    - Generator availability based on available specific or generic statistics (e.g. NERC GADS)
    - Can use seasonal outage rates, if available
    - Full or partial forced outages are modeled
    - Ramping rates
    - Maintenance Scheduling
    - Includes existing generation units, as well as future resources as required
- Monte-Carlo selection of
    - Generator outages/derates
    - Load profiles
    - Renewable energy profiles
- Bus based load shedding
- Curtailable wind generation
- Ancillary Service Modeling
- Transmission Constraint Modeling
    - Single-node (no transmission),
    - Zonal mode, and
    - Full transmission network simulation studies, including contingency constraints, corridor constraints and nomograms, depending on requirements

- Operational constraints via Expected Flexibility Deficiency function (discussed below)

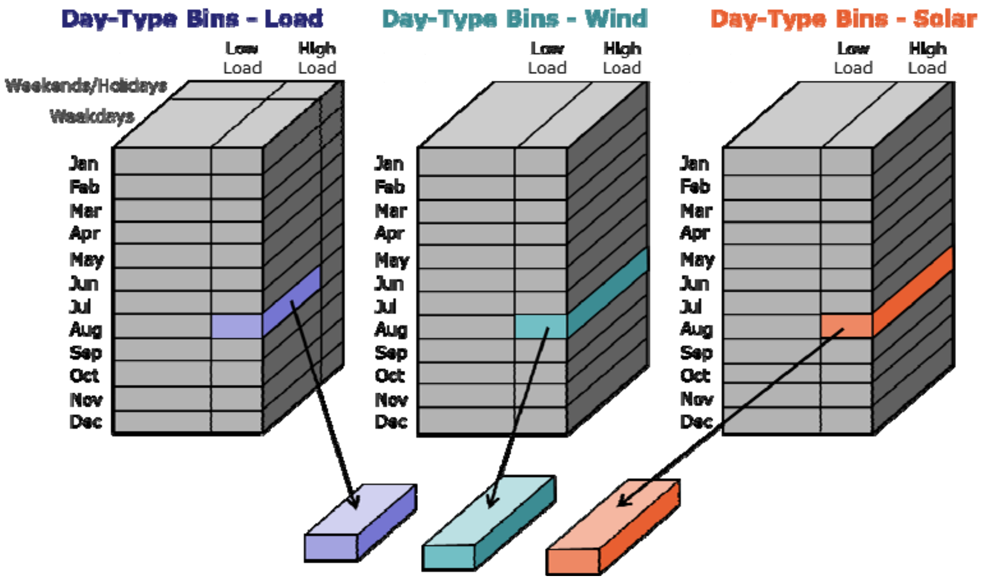


Figure 8. Monte Carlo Selection of Load and Renewable Profiles

In order to preserve daily shapes, ramp rates, and correlations, an entire day can be randomly selected from bins of similar days (see Figure 8). Historical days are binned according to month, and high vs. low daily energy demand (and weekend/weekday for load bins). Each wind/solar daily profile is associated with load categorization (neglecting weekend/weekday). Finally, the Monte-Carlo engine mixes and matches load, wind, and solar daily profiles within each day-type bin to realistically increase the variability of the input data.

Recent computer technology breakthroughs with high performance multi-core processors and optimizing compilers make these computations feasible. ProMaxLT™ ReFLEX utilizes the same basic formulation used in ISO market clearing engines, where a full power flow solution is performed for each trading interval and violated/near violated constraints are selectively added into the LP formulation using shift factors from the full network matrix linearized about the operating point from the power flow solution. Many performance enhancements have been successfully applied to make this approach computationally viable for high iteration Monte-Carlo studies.

7.1 Incorporating Flexibility Requirements

The ProMaxLT™ ReFLEX module develops plans for reliable system operation, by simultaneously considering:

- Capacity Requirements – according to traditional metrics for capacity planning
- Flexibility Requirements – accounting for the limitations of the fleet in time sequential operations

The resulting solution is the least-cost array of portfolio and/or operational changes that satisfy all these objectives. The relative value of resource types over multiple time scales is also captured, e.g. energy storage can provide fast ramping response over a short-time period, while CCGTs provide load-following capacity and ramping capabilities.

A key breakthrough has been the incorporation of the endogenous ramp and reserve policies directly into the ProMaxLT™ ReFLEX optimization engine. This approach makes it computationally feasible to consider the impact of operational constraints within long-term reliability studies. This is accomplished through the introduction of an Expected Flexibility Deficiency (EFD) function, to determine the anticipated amount of un-served energy caused by a lack of flexibility in the generating fleet. The EFD is a function of the ramp and reserve policies, meaning that as more reserve capacity and/or ramping flexibility is added, more of the load will be served, and the flexibility deficiency will correspondingly drop.

The EFD is computed before executing the unit commitment, and it is derived from historical system load/renewable data, as well as the forecasts associated with a given unit commitment window. For example, a day-ahead unit commitment problem that provides hourly schedules requires EFD surfaces built from day-ahead hourly forecasts. The EFD surface requires enough historical data to ensure that the forecast errors and inherent variability are well-represented. With the EFD included directly into the unit commitment algorithm, ProMaxLT™ can decide whether, for example, it is more cost effective to turn on additional flexible thermal units, curtail renewables, or experience a flexibility violation.

Ramp and reserve policies must be defined, in order that the EFD can be determined. An example of a ramp policy is that the average ramp of the system is equal to the forecasted ramp (the difference between sequential forecasts, divided by the length of the forecast period) plus some constant, x [MW/min]. An example reserve policy might be that y% of the forecasted net load is held in reserves. For these policy formulations, the EFD surface is built as a function of x and y (see **Error! Reference source not found.**9). Note that the x and y variables are optimized within the unit commitment problem.

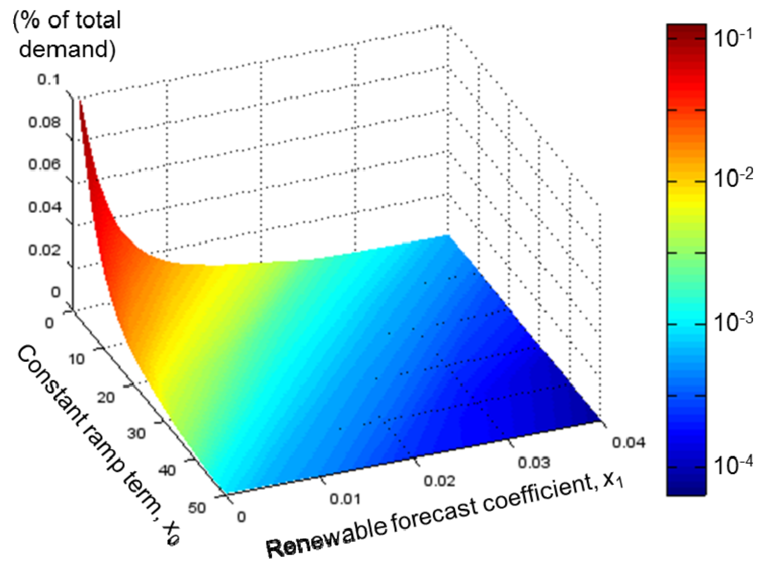


Figure 9 Sample Expected Flexibility Deficiency (EFD) function

Furthermore, one facet of the EFD function could be determined by letting x = 15MW/min, and y = 8% (see Figure 1010). The gray area is the flexibility deficiency, due to the lack of ramping and/or reserves. Each point in the EFD surface is then produced by repeating this calculation for each unit commitment time step and dividing the resulting total flexibility deficiency by the total energy demand to provide a normalized EFD. Finally, the entire EFD surface is constructed by varying "x" and "y" over a representative range.

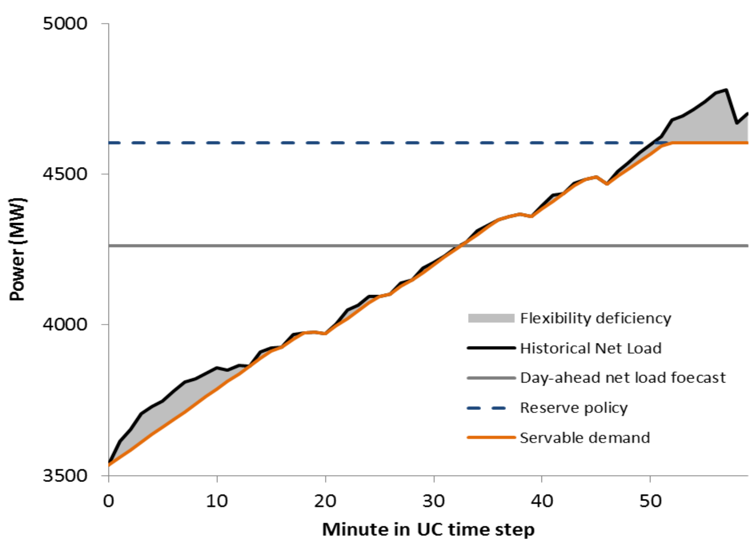


Figure 10. Computing Flexible Deficiencies using Historical Net Load Data

7.2 Flexibility Constraint Results

The ProMaxLT™ ReFLEX module simulation results allow the following system conditions to be analyzed:

- Flexibility violations that may occur, because the penalty cost of these violations is less than the commitment of additional resources,
- Optimal levels of reserves and ramp-rates, based on ramp/reserve policy,
- Economic "pre-curtailment" of renewables that avoid flexibility violations and/or commitment of excessive fast-ramping generation.

These are just a few examples of the increased visibility that can be achieved through the use of ProMax/ReFLEX.

Each study identifies the amount of resources committed for each day and commitment is broken out by resource type;

- Gas Turbines,
- Hydro,
- Resources designated as "Must-Run",
- Co-Gen,
- Imports,
- Renewables

Existing reliability simulation tools do not properly consider operational flexibility constraints and often fail to predict loss of load events that would occur due to insufficient flexibility during periods of high renewable generation levels. Through the creation of the Expected Flexibility Deficiency (EFD) function, ECCO is able to effectively incorporate ramp-rate and reserve limitations into the optimization. The result is that ProMaxLT™ ReFLEX is able to simulate loss of loss events where the generation fleet is unable to meet the peak load (from a capacity perspective), but also those events where the fleet is unable to follow the variations of the net load throughout the entire study period.

In Figure 11, the load forecast is plotted as the heavy black line, and the curtailment of renewables is shown above that in light-green. Curtailment occurs between 0700 and 1600, which means that based on the commitment, renewables will need to be backed down during those hours.

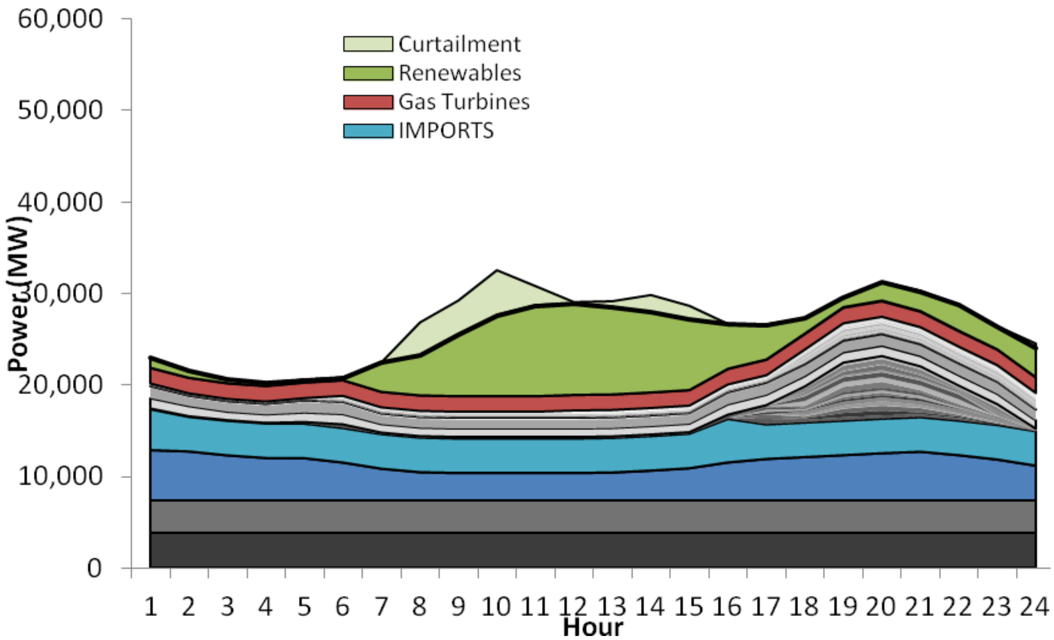


Figure 11: 24-hour results showing curtailment required for flexibility

Figure 12 shows results for the same day, with a different perspective. The load forecast (heavy black-line) is still shown for the commitment period. In addition, the light-blue range represents the total "Reg-Down" and "Reg-Up" capacity for the period being studied. The figure shows a Reg-Down shortfall between the hours of 0700 and 1600. This illustrates the inability of the system to move downward during those hours.

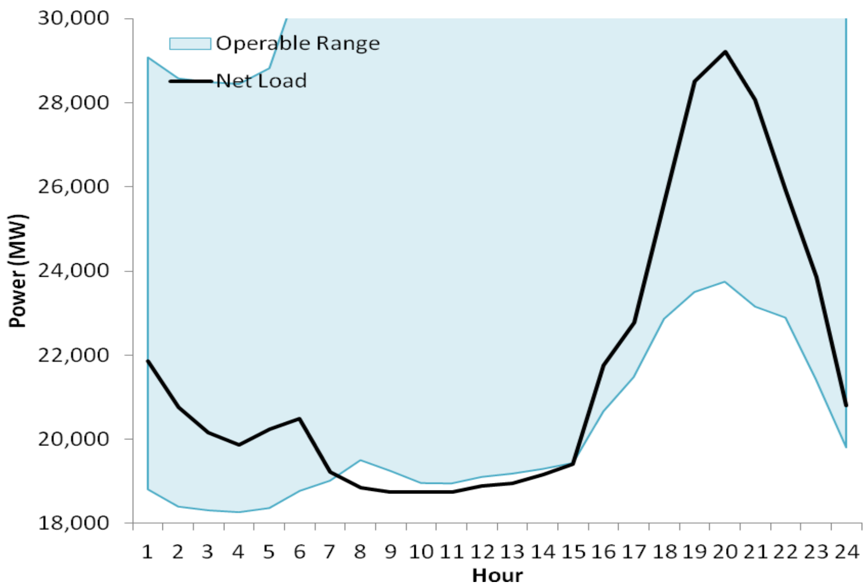


Figure 12: 24 hour results showing operation flexibility

7.3 Computational Performance

ECCO has achieved outstanding performance results through a combination of leveraging the latest capabilities of hardware/processors, coupled with software improvements in management of various aspects of the calculation process.

Below are some performance metrics based upon our experience:

- 325 unit case, with mix of combined cycle, GT, Hydro and renewables,
- 500 day, single-zone simulation, total execution time varies between 1 to 6-hours on an Intel Core-i7 2700K processor machine with 16GB memory. With an approximate observed run-time of 5 to 10-seconds for each "study day" running a full MIP simulation.

- Run-time varies due to imposed constraints associated with volume of renewables modeled in relation to the total available resource pool. Other settings in MIP may also be tuned to increase performance while not compromising the results.

ECCO has a large array of high performance servers available to perform extensive Monte-Carlo simulation studies.

8 Delivering Speed

We have outlined above the steps we have taken to deliver greater precision in the reliability and market forecasts delivered by ProMaxLT™. Precision is retained in the ProMaxLT™ high-performance environment. ECCO has rigorously tested and benchmarked the results obtained from our software for various jurisdictions to assure the highest quality results coupled with the industry's fastest solution processes possible.

As advancements are made in updated algorithmic methodologies ECCO will be sure to test and update our technologies. Add to that the advancements made, almost daily, with new computing hardware and solving more complex problems will continue to progress towards speedier solutions.

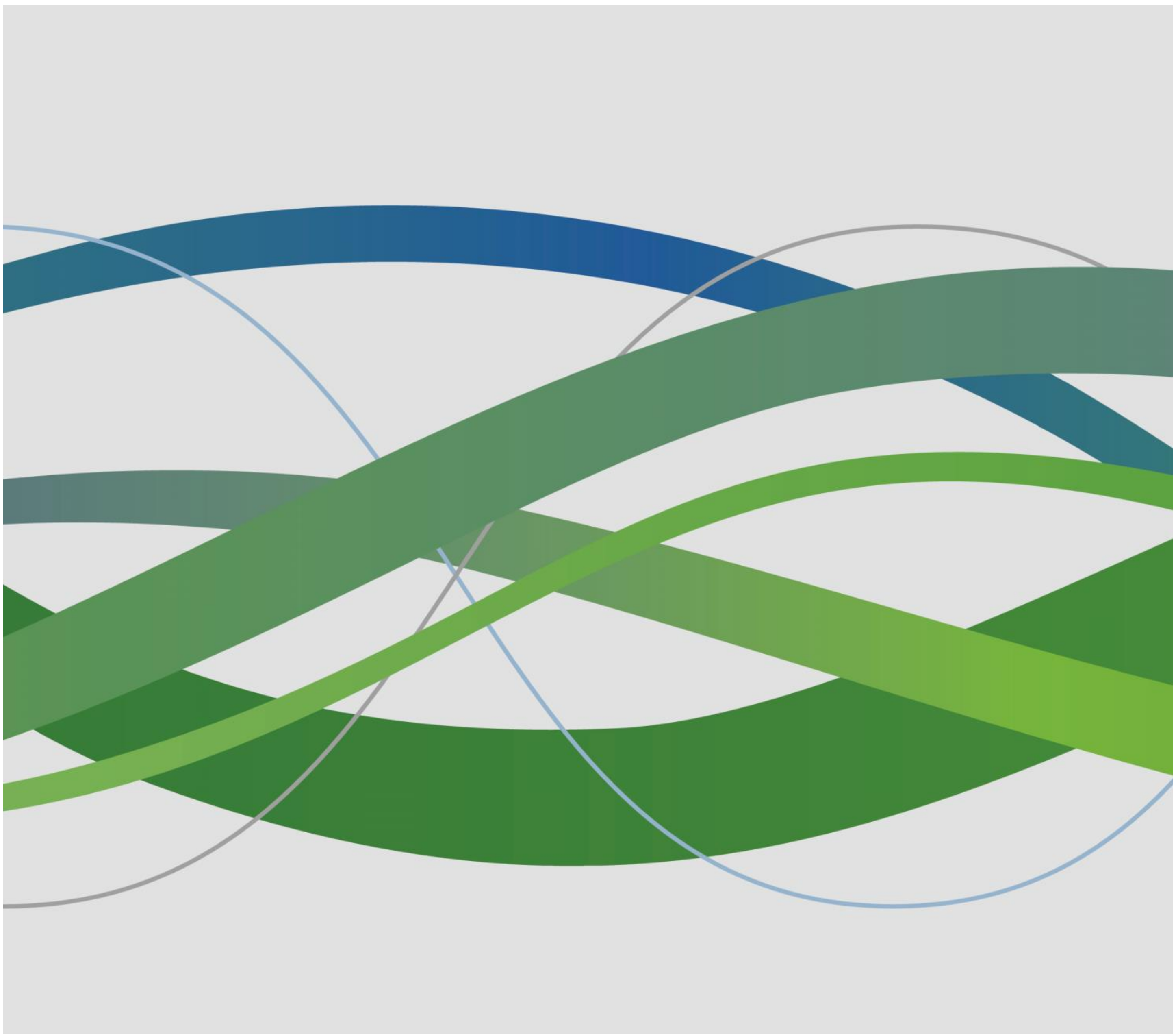
F. Qualitative Investigation of Distribution System Technical Issues and Solutions

Qualitative Investigation of Distribution System Technical Issues and Solutions

Ranking of Distribution Smart Grid Options

Prepared by KEMA, Inc. as Subcontractor to E3

August 23, 2013



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1. Qualitative Investigation of Distribution System Technical Issues and Solutions

1.1 Executive summary

Each of the High RPS scenarios in the E3 report, "Investigating a Higher Renewables Portfolio Standard in California," assumes growth in the level of distributed renewables, particularly PV solar projects (residential, commercial and/or utility scale). Even at the 33% RPS level, California utilities are struggling with how to address technical impacts from distributed PV generation on the distribution grid. To date these technical issues have been mostly mitigated through upgrades to the utilities' distribution system infrastructure. However, such upgrades can be costly. As an alternative to grid upgrades for accommodating future PV expansion, California utilities are considering a range of smart grid (SG) options and/or designation of solar "zones" where more PV can be added with minimal or no grid upgrades. Prudent deployment of distribution SG technologies and designation of such solar zones both have the potential to reduce costs for system upgrades required at higher penetration levels of distributed PV generation.

DNV KEMA performed a *qualitative* review and ranking of selected SG technologies with potential to support distributed PV growth in California.[1] These technologies included both smart grid options at PV sites and smart grid options on the utility grid. The assessment included an overall ranking of the candidate SG technologies based on technical and economic factors, barriers to deployment of such technologies, and available solutions for overcoming such barriers.[2] With timely phase-in of the higher ranked SG technologies and/or designation of smart PV zones, we conclude that wholesale replacement or redesign of California's distribution systems would not be needed even under high penetration distributed PV scenarios.

Solar PV projects utilize solid state inverters to transform energy output from PV panels into alternating current (AC) power. Several SG technologies covered in this study fall under the heading of "smart inverters." Such inverter features are already in common usage on renewable generation projects on US transmission systems. However, very few of the existing distributed PV inverters have such features. This report uses to the term "legacy inverters" to refer to this older technology. In fact the new smart inverter features are not covered by existing US distributed inverter standards (i.e., IEEE 1547 and UL 1741). Efforts are underway to modify the inverter standards to add smart inverter features, but several years

[1] In conjunction with this qualitative smart grid analysis, the main E3 report includes a quantitative assessment of distribution upgrade cost scenarios, but those cost estimates do not consider the impact of distribution SG options such as those considered by DNV KEMA..

[2] Detailed benefit-cost analysis was beyond the scope of the current study.

may be needed to complete this process. In the meantime California utilities are struggling with unknowns related to the transition from legacy inverters to smart inverters (e.g., timing, scope, feasibility, etc.) This report concludes that California regulators and policy makers may need to take a leading/proactive role in the transition process if the state's goal is to achieve RPS targets above 33% over the coming decade. One way to exert such leadership is through introducing timely changes to California's inverter requirements in CPUC Rule 21.[3]

In conjunction with the DNV KEMA study the California utilities formed a Distribution Work Group (DWG)[4] which selected the following SG technologies for inclusion in DNV KEMA's qualitative technology assessment:

- Smart PV inverter capabilities
  - local voltage sensing and control
  - real-time remote monitoring and curtailment capabilities
  - "ride through" capabilities for utility system disturbances
  - balancing current flows on all three "phases" of connected distribution feeders
  - PV inverters with battery storage for PV "ramp" smoothing
  - PV inverters with battery storage for feeder peak demand reduction
- "Bi-directional" feeder/substation protective relaying
- Advanced distribution automation (DA)
- Forecasting tools for predicting distributed PV generation output
- Dynamic feeder current ratings
- Solid state feeder voltage regulators

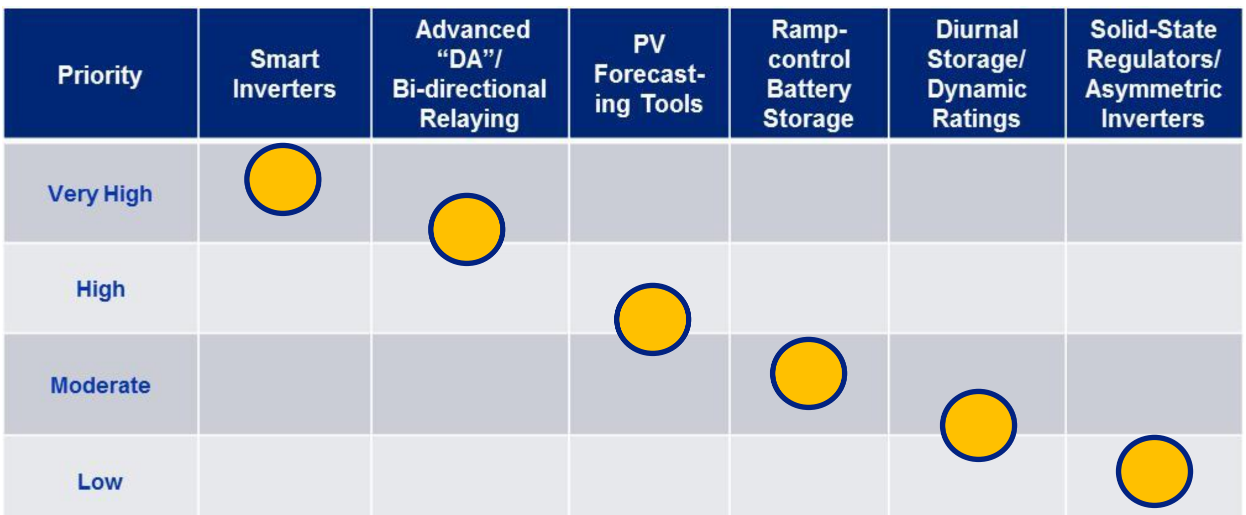
[3] The CPUC/CEC recently initiated a joint effort to evaluate candidate features for smart DG inverters. See CPUC/CEC Joint Workshop, "Candidate Smart Inverter Capabilities for Improving Distribution Grid Functionality," June 21, 2013.

[4] The DWG included representatives from LADWP, PG&E, SCE, SDG&E and SMUD.

For each of the selected SG technologies DNV KEMA reviewed available manufacturer information, research reports, industry papers, status of deployment, its potential impact on PV integration, available information on the costs to deploy each technology, their potential for deferring distribution system upgrades, interaction with other SG technologies, barriers to deployment and potential solutions to such barriers. Following extensive discussion of these factors with the DWG the following ranking of SG technologies was developed based on potential to help ease the burden of integrating high levels of distributed PV by 2020 in California:

Figure 1

Overall SG Technology Ranking



Priority level is based on ability to provide widespread support for high level distributed PV deployment in California by the 2020 timeframe

We conclude that the SG technologies shown on the first three columns above have good potential for avoiding more costly distribution system upgrades that would otherwise be needed with high levels of distributed PV deployment. We also conclude that the cost effectiveness of SG technologies shown in the remaining columns could be beneficial, but need to be evaluated on a case-by-case basis.Potential distribution system technical issues under high penetration of renewable DG

1.2 Potential distribution system technical issues under high penetration of renewable DG

Regardless of their nominal voltage level (e.g., 23 kV, 13.8 kV, 4.8 kV, etc.) California's existing distribution systems were originally designed and built for the sole purpose of serving customer load and assuming that power would always flow from the distribution substation to downstream customer loads. California distribution feeder topology, conductor sizes and voltage control devices were originally planned and designed on this basic premise. The addition of DG on distribution systems alters this basic paradigm by adding generation "downstream" from the utility substation. This causes a wide range of technical impacts on the distribution system which, depending on the specific DG and feeder characteristics involved in each case, can either be beneficial or detrimental to feeder operation.

Beneficial impacts typically occur when the quantity of DG is small relative to the local demand, in which case DG reduces the "apparent" or net local customer demand along a feeder. However, even in such cases DG can create technical problems for the utility if the DG output is highly intermittent (i.e., PV or wind). Such intermittency can cause unacceptable voltage swings seen by other customers on the feeder. Furthermore, if aggregate DG output exceeds the local demand on a feeder it can cause oversaturation on the feeder (e.g., power flowing on the feeder toward the distribution substation) – which is somewhat analogous to driving a car in reverse at high speeds. The presence of significant levels of DG can also have detrimental impacts on utilities' protective relay system operation (e.g. fault detection and clearing) and can aggravate transient voltage and frequency conditions that occur on the utility system. The aggregate response of distributed PV inverters to such system conditions can be especially problematic for utility systems at high levels of PV penetration.

The good news is that all of the associated technical problems can be solved. The bad news is that the solutions can be costly. Prudent deployment of distribution SG technologies can reduce those costs. So can designation distributed PV smart zones where system upgrade requirements are minimal. Both approaches are addressed in this report.

For each SG technology included in this assessment DNV KEMA considered the following questions:

- To what extent could the technology resolve the types of technical issues created by high penetration levels of distributed PV?
- What is the current status of the technology's maturity and will it be available in time to support California's 2020-2030 RPS targets?
- How much would the technology cost to deploy and does it offer good potential to avoid costly distribution system upgrades that may otherwise be needed as a result of PV expansion?
- How does it interact with other SG technologies?
- What are the barriers to deploying the technology on a widespread basis in California and how can these is overcome?

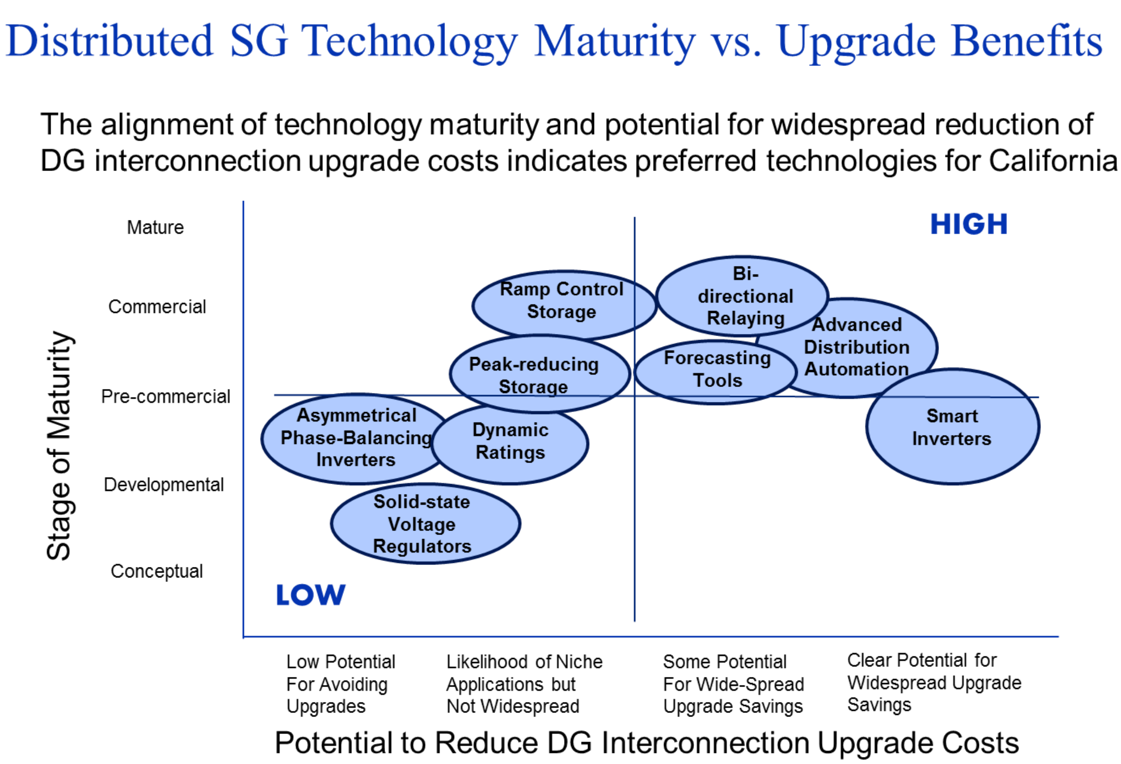
1.3 Results of the Smart Grid survey

Each of the technologies chosen for review has the potential to mitigate the types of detrimental impacts that PV inverters can have on the operation of utility distribution systems – such as voltage control and flicker concerns related to the variable nature of PV output, feeder oversaturation (e.g., reverse power flow), adverse effects on distribution system fault detection and clearing, widespread tripping of distributed PV inverters for transient system conditions, etc.

In conjunction with the DWG, DNV KEMA summarized the findings for each SG technology as shown in Appendix A.

Based on this information DNV KEMA developed the following graph of SG technology options which compares the maturity level of each technology vs. its potential ability to defer utility distribution system upgrades related to PV interconnection.

Figure 2



This assessment concluded that the highest ranked group of SG technologies includes advanced PV inverter features, advanced distribution automation (DA) and bi-directional protective relaying on utility distribution systems. All of these technologies are available in 0-3 years and have good potential for mitigating PV impacts, but are not yet widely deployed in California. They offer good near-term options to help ease the burden of integrating higher levels of PV penetration on California distribution systems in the coming decade in a cost effective manner. However, industry standards for some of the inverter and advanced DA features – including testing requirements and communication protocols – are still evolving. In fact the status and timetable for development of such standards and test protocols were the focus of the recent CPUC/CEC joint workshop on candidate smart inverter capabilities. We assume that the CPUC/CEC process will also consider the range of PV inverter sizes over which advanced inverter capabilities are needed in California.[5]

A second group of SG options was identified with some potential for cost effective mitigation of PV impacts in the 1-5 year timeframe. These included PV forecasting tools and Battery Energy Storage Systems (BESS) with capability to mitigate the effect of fast ramps in PV generator output associated with passing cloud fronts. DNV KEMA's assessment found these SG options to be readily available with current technology, but concludes that the timetable for deployment of these technologies may be delayed due to costs. In regard to the use of battery energy storage systems (BESS) for smoothing of PV ramps we conclude the technology offers near-term benefits to PV integration and can be achieved by at individual PV inverters, community-based projects and/or utility scale projects, but is most economically viable on projects of 100 kW and larger. The CPUC's current R.10-12-007 proceeding is seeking ways to incentivize deployment of BESS technology in California. This important proceeding offers a public forum for vetting the full range of BESS implementation issues and benefits.

The third group of SG technologies – including BESS for demand reduction (e.g., diurnal storage), dynamic feeder rating tools, solid-state line voltage regulators, and asymmetrical phase-balancing inverters – was found to be comparatively young in terms of deployment at the distribution level. While they each show future promise for supporting PV integration on California distribution systems, the value proposition is not currently as clear as with the higher ranked technologies. While they may only offer limited "niche" deployment opportunities in the near term, they are still options to watch in coming years. In regard to BESS for peak-reduction, cost justification will be driven to a large extent by future reductions in battery prices as the technology continues to evolve. This RD&D area is deserving of future PIER and EPIC funding.

[5] As one benchmark, Germany currently has a mandatory PV inverter retrofit program that requires adding frequency ride through and curtailment capability to all PV inverters with ratings of 10 kW and above.

KEMA's assessment included an identification of barriers to deploying these SG technologies in support of achieving high RPS targets in California, as well as potential solutions for mitigating such barriers. These barriers are captured on a technology by technology basis in Appendix A and include a range of regulatory/statutory/policy barriers, economic viability, technical challenges, lack of current applicable standards, etc. Some of the key issues and potential solutions for further consideration include the following:

- Industry-wide standards for distributed smart inverter features, including testing and telecommunication protocols, may not be in place for several more years.
  - Solution – encourage adoption of appropriate standards through existing industry bodies such as the IEEE 1547 standards group. Alternatively, California regulators could lead this process through adopting statewide "smart inverter" standards through changes to Rule 21. In this regard it should be noted that California's initial Rule 21 was released prior to the current IEEE 1547 standard and served as a benchmark for the IEEE. A similar approach could be used by California regulators to motivate adopting of the smart inverter standards and testing protocols.
- Difficulty for PV customers to implement Smart inverter features as UL test standards for many of these inverter features have not yet been developed.
  - Solution – support test standards development and implement updates to Rule 21 related to remote real-time monitoring, reactive power/voltage control, ride through, emergency curtailment, etc. along with appropriate regulatory/market incentives.
- Economic viability of BESS storage options.
  - Solution(s) – identify appropriate measures through the R.10-12-007 preceding that could help to economically incentivize storage for PV ramp rate control (smoothing) as well as for peak shifting applications. Support technology development with goal of reducing battery costs through PIER and EPIC programs.

While the focus of this study is on SG technologies that will help ease the level of distribution upgrades needed for distributed PV expansion, we should point out that there is a growing concern in the industry about the risk of widespread tripping of legacy PV inverters due to frequency or voltage deviations on the bulk power system. In the worst case scenario, widespread tripping of PV inverters could destabilize the whole grid. As one example, high system frequency can occur during light system loads if there is excess renewable generation on the system. This can cause the system frequency to rise above the frequency trip-point of legacy inverters. Concern over this condition in Germany has prompted a mandatory retrofit of PV inverters in that country in order to add improved ride through and curtailment capability. Other voltage and frequency conditions on the bulk power system can also trigger large scale tripping of distributed inverters. This risk will grow as more PV inverters are added on the distribution system, but can be mitigated through suitable smart inverter features. Inverter ride through and curtailment capabilities on distributed PV inverters should be made mandatory in California in order to avoid such system risks at 40-50% RPS levels. Timely implementation of such requirements would avert the need for a costly retrofit program in the future in California.

1.4 Smart siting of distributed PV

One "smart siting" concept under discussion in California is to establish solar PV "zones" in places where the distribution system is capable of absorbing more PV capacity without the need for costly infrastructure upgrades. In the absence of any type of locational signals, the trajectory of distributed PV siting will tend to favor rooftop PV projects wherever available rooftop space is the greatest (e.g., urban and suburban areas) and larger, ground mounted (e.g., wholesale PV projects) will tend to favor rural areas where more low cost land is available. Unfortunately, distribution feeders in rural areas tend have much lower capacity than in urban/suburban feeders. Rural feeders tend to be much longer, have much lower levels of customer load, and be built using smaller conductor sizes. Therefore, rural feeders are more likely to experience voltage problems and back feed (reverse power flow) when large, wholesale PV projects are added. This translates into a need for more extensive infrastructure upgrades, as often seen in utility system impact studies. In urban and suburban areas the aggregate impact of many smaller rooftop PV at some level of penetration will likewise lead to serious impacts on those distribution feeders. This can be compounded by the addition of any larger, wholesale PV projects on an urban/suburban feeder since many of the effects of PV capacity installed on a feeder are additive.

Therefore, while on the surface it may appear beneficial to bias the siting of large-scale PV siting toward urban/suburban zones this in fact has several drawbacks such as:

- There is less land available in such areas which will tend to restrict wholesale PV penetration
- Land restrictions will also limit the number of BESS options in urban/suburban areas
- The additive effect of rooftop PV and additional wholesale PV on urban/suburban systems can also trigger large scale distribution system upgrades

In this context it's important to note that "smart inverters" are co-located at PV project sites and require essentially no more space than legacy inverter designs. Therefore, smart inverters offer an excellent mitigation option in urban/suburban areas where access to affordable land is often limited. Smart inverters provide some benefits for rural PV projects as well, but unfortunately they don't resolve the risk of back feed from occurring on lightly loaded rural feeders.

Another argument in favor of implementing smart inverter requirements is the benefit they provide during the operation of normally-open tie points between distribution feeders. Such tie points are commonly used to pick up portions of one feeder from an adjacent feeder when the normal source the first feeder is interrupted. This is can occur due to feeder fault events, repairs or construction when feeders must be sectionalized and some parts of the feeder loads transferred to one or more adjacent feeders. If PV located on the first feeder has a smart inverter, the benefits of that smart inverter are also seen by the adjacent when it picks up part of the first feeder upon closing of the normally-open tie. On the other hand, this may not hold true in those cases where a smart grid option is located upstream from the PV project (e.g., closer to the distribution substation bus and remote from the PV location). In that case, the smart grid technology may be unable to provide any benefit to the adjacent feeder during the temporary operation of the tie switches.

It should be noted that one California utility (SMUD) already designates specific PV zones or "sweet spots" on their distribution system that are best suited to PV interconnection. However, this is facilitated by the fact that SMUD uses a limited set of feeder conductor sizes which in practical terms means that many SMUD feeders have some headroom to interconnect DG capacity. While this may be conducive to PV integration within SMUD, feeders at the other California utilities generally have less headroom – especially in rural areas. Nevertheless, the PV zone approach may still be applicable to other California utilities if it is based on technical analysis that identifies the current "sweet spots" where PV can be readily added on the distribution system. In fact, a recent SCE study on options for siting Localized Energy Resources "LER" found that:

> "While smart grid technologies are expected to mitigate some of the potential impacts of adding LER, the application of these technologies is likely several years away due to the need for standards and technology development and demonstrations. Thus, strategies to encourage LER to interconnect in preferred locations within the urban network would, when balanced with other procurement factors, likely be of benefit to SCE's customers and to the developers due to the projected cost savings estimated in this study."[6]

We concur with SCE that adoption of the required smart inverter standards is still several years away, but we also conclude that this timetable will enable smart inverters to provide significant support in achieving the next round of statewide RPS targets (e.g., for the 2020-2030 timeframe). However, we also conclude that smart inverters alone will not mitigate all of the technical issues that will occur due to widespread distributed PV deployment under high RPS scenarios. Therefore, the other SG technologies discussed above – including those for installation on the utility distribution grid – also must be pursued.

Finally, in addition to widespread deployment of smart inverters and other SG technologies, we conclude that there are clear benefits to "smart siting" of distributed PV generations. In that regard we fully concur with SCE's earlier conclusion that:

> "LER deployment would benefit from a carefully designed (i.e., "guided") approach to locating (PV) installations. These locational costs should thus be considered in utility evaluation of projects; effective changes to the interconnection processes for LER, e.g., Rule 21, or competitive application processes that properly evaluate system impact..."[7]

[6] The Impact of Localized Energy Resources on Southern California Edison's Transmission and Distribution System, *May 2012, page 7.*

[7] Ibid.

The implementation of such locational siting alternatives and incentives is clearly another area deserving consideration by regulators and policy makers.

1.5 SG technologies excluded in this survey

In closing, we should note that choice of the SG technologies to include in this qualitative assessment was focused on technologies with potential for widespread deployment in the distribution system in the near-term. In other words, technologies that are – or might soon be – economically viable on any feeder or PV inverter. We did not include other technologies such as D-STATCOM which are currently available, but tend to be very expensive and thus not generally an option for widespread deployment. Such technologies clearly have an important niche, but tend to be driven by a more unique set of circumstances than distributed PV integration. However, such technology options may be worth evaluating for very large, wholesale PV projects which tend to be located at higher voltage busses on the system.

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I) Dynamic Feeder Ratings

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2) The Valley Group | CAT-1™ Transmission Line Monitoring Systems" | n/a | n/a | Brochure

J) Solid State Line Regulator

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2) Ashley-Edison | "Pen H Series" | n/a | 03/2013 | Brochure
3) Greentechgrid | "Solid State Transformers Part II/Distribution Grid 2.0: The Dawn of Solid State Transformers" | E. Wesoff, R. Thompson | 2011 | Article
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K) Phase Balancing Smart Inverter

1) Journal of Electrical Engineering & Technology | "Design of an Asymmetrical Three-phase Inverter for Load Balancing and Power Factor Correction Based on Power Analysis" | M. Mokhtari, S. Golshannavaz, D. Nazarpour and F. Aminifar | Vol. 6, No. 3, DOI: 10.5370/JEET.2011.6.3.293 | 2011 | Paper

Appendix A - Smart Grid Technology Assessment Summaries

Smart Grid Technology	***Advanced Distribution Automation (DA)***
General Description	Smart Grid software (SW) / Hardware (HW) technology that monitors and seeks to optimize conditions of the distribution network through automated control of devices on a feeder. Typically, legacy DA monitors some combination of voltages, power flows, loads and operational cost factors (e.g., losses). Legacy DA can provide automated control of voltage regulators and capacitor banks for improved power quality and reliability. Advanced DA includes capability for monitoring and control of DG and other types of SG technology such as Advanced Metering Infrastructure (AMI). If regulatory/market protocols allow, Advanced DA can be used to control PV inverter output (power and/or voltage output) or inverter operating modes (e.g., enable or disable ride through capability). Advanced DA can also be used to curtail customer loads as a last resort, if such provisions exist (e.g., through communications with AMI).
How it Impacts DG Deployment	Would allow higher DG penetration levels without detrimental impacts on power quality and reliability through coordinated control/interaction with other SG technologies such as advanced inverters, AMI, etc.
Cost to Deploy *(e.g., per typical feeder)*	Costs will vary depending on the functionality of the DA employed: • Centralized vs. Decentralized control • Type of Communication and Protocol • PV and Storage Inverter Technology available Sample range of cost estimates: $ 75K – 150K per feeder (equipment only) $ 125K – 250K per feeder (equipment & installation labor)
Potential for Deferring Distribution Upgrades	Advanced DA control would allow for high DG penetration levels on existing networks in many cases without replacement and/or expansion of utility distribution system voltage control apparatus or conductor upgrades – particularly if suitable regulatory/market protocols exist for control of PV inverter operating mode or output level/curtailment.
Current Status of Technology Deployment	Legacy DA systems are currently deployed on a cross-section of distribution feeders in California. These systems automate regulator, capacitor and switching to improve feeder operation. Advanced DA technology is becoming commercially available, but more standardization of communication protocols is needed before suitable for widespread deployment in California.
Interaction with Other Smart Grid Technologies	Advanced DA functionality would improve with more controllable devices and communications. Additional information from AMI (supported by secure communications) would dramatically improve the range of Advanced DA functions. Could also be integrated with forecasting applications to take pre-emptive action, particularly if integrated with AMI, PV inverters and/or distribution energy storage.
Barriers to Deployment	Allowing utility DA control over 3rd party DG units, particularly PV, will require changes to market/regulatory schema. Also, lack of uniform equipment standards and communications/interface protocols may impede deployment.
Potential Solutions to Barriers	Development/deployment of upgraded equipment standards and common communications/interface protocols. Adoption of suitable market/regulatory schema related to PV inverter communications and curtailment.

Smart Grid Technology	*Bi-directional Feeder/Substation Protective Relaying*
General Description	The type, size and number of DGs on a feeder (e.g., total DG generation compared to feeder demand) - and the DG point of connection on the feeder - are all critical factors in the design of feeder/substation protective relaying. When a very large number of DGs are connected, bi-directional feeder and substation relaying is needed to accommodate reverse power flow. Other relaying issues related to DG also need to be considered. For instance, downstream DG affects feeder fault current levels and fault detection. Protective relaying on an unfaulted feeder can see a fault contribution from downstream DG during a fault on adjacent feeder, bus or supply line which may lead to unnecessary tripping (and customer interruption) on unfaulted feeders. In addition if aggregate DG capacity exceeds one third of minimum load of the feeder, use of a direct transfer tripping scheme to isolate downstream inverters should be considered as currently being discussed in the IEEE 1547 working group (e.g., sections 4.2.1, 4.4.1 and 8.4.1.3.1).
How it Impacts DG Deployment	As higher levels of DG are installed California more and more feeders will experience periods of reverse power flow during the year. Many of the legacy protective relaying systems on utility distribution feeders/substations in California will not operate properly under such conditions which will require additional system upgrades and may inhibit/slow the growth of PV. Back feed can also impact the operation of pole mounted line reclosers used further out on feeders at some utilities. As per IEEE 1547-2, section 8.2.2, the DR shall cease to energize the feeder to which it is connected prior to reclosure by the utility feeder breaker or recloser. This may require modification of reclosing scheme at additional cost.
Cost to Deploy ***(e.g., per typical feeder)***	The cost of replacing legacy protective relaying with bi-directional relaying on an individual utility feeder is estimated to run about $50K (installed). Similar relay upgrades may be required on substation transformer bank protection packages if the aggregate output of DG on feeders served by a particular substation bank/bus section exceeds the minimum load on the bank/bus section. If so, the total installed cost for relaying upgrades on one feeder and one bank could run $100K or more. In some cases, a transfer trip protection scheme (to ensure proper isolation of DG) should also be considered – at additional cost - to ensure proper operation of protection schemes.
Potential for Deferring Distribution Upgrades	Bi-directional protective relaying on utility feeders/substations allows greater PV penetration on existing networks without expansion of utility distribution network – such as building a dedicated feeder (gen-tie), designed for back feed, from a larger PV project to the distribution substation.
Current Status of Technology Deployment	California feeders currently have various classes of protective relaying installed (directional, non-directional, & bi-directional). However, only bi-directional relaying can provide for use of unique trip settings during either direction of current flow (e.g., normal or back flow). By 2030, it is predicted that at least 90% feeders 90%) in California will have bi-directional relaying installed, which assumes the replacement of many current legacy relaying systems. In addition, other more advanced types of adaptive protective relays utilizing communications between the relay and other devices on the feeder can be installed to help ease the impact of even higher PV inverter levels, if needed. For PV plants larger than 1MW, California utilities currently require SCADA monitoring at the Point of Connection, and transfer tripping capability may be included on some larger DG projects.

Interaction with Other Smart Grid Technologies	There is no direct interaction between bi-directional relaying and distribution SG technologies of interest, other than the potential need for transfer tripping of PV inverters as noted above. However, the installation of advanced (adaptive) protective relaying systems would further improve other SG device functionality by integrating technologies that are equipped with open communication protocol. This would particularly be useful where transfer scheme is applied that requires communication channel.
Barriers to Deployment	For the most part, the replacement of non-directional legacy protection systems is currently being done in California on a feeder by feeder basis as new PV projects trigger a need for such relay upgrades - with the associated upgrade costs paid by the "last" PV customer to come on the system. This approach could impede or delay reaching higher RPS levels.
Potential Solutions to Barriers	Implement a strategic process for replacement of legacy protective systems on feeders in California, which could include a methodology for allocation of the related costs between developers and utilities since the new relay technology may provide additional utility benefits. Also, for higher PV penetration levels, California should support development of communication based advanced adaptive protective relaying system standards and common interface protocols.

Smart Grid Technology	***Dynamic Line Ratings (DLR)***
General Description	Dynamic thermal rating of distribution overhead (OH) and underground (UG) lines through specialized hardware (HW) / software (SW) integrated into the Distribution SCADA system, to provide an increase in capacity compared to static ratings, through data/measurements related to conductor temperature, loading cycle, wind speed and direction, ambient temperature, forecasted conditions, conductor sag, conductor tension, etc.
How it Impacts DG Deployment	Since dynamic ratings allow power lines to be used to their full thermal capability under real-time conditions, more energy could be delivered annually from DG without exceeding conductor ratings – particularly on overhead line segments. Under extreme operating conditions (e.g., excessive ambient temperatures that exceed steady state rating assumptions), DLR can provide more reliable operation of the grid by maintaining loading within real-time conductor capabilities if combined with provisions for curtailment of DG and/or automated load shedding.
Cost to Deploy *(e.g., per typical feeder)*	Cost will vary depending on the type of DLR technology deployed such as: • Tension based • Sag based • Ambient measurement based, etc. $ 200K per circuit (equipment only) $ 400K per circuit (equipment, installation, engineering & design) These costs may drop as transmission scale DLR systems are modified for lower voltage distribution applications.
Potential for Deferring Distribution Upgrades	Under many ambient conditions, distribution lines can be operated at a higher capacity – however we conclude that DLR will not defer feeder conductor upgrades since the real-time conductor ratings that will occur at the time of the annual feeder peak demand can't be reliably predicted in advance. Also, DLR has limited applicability to UG feeder sections.
Current Status of	Current utility deployment of DLR technology is focused on transmission rather than

Technology Deployment	distribution, and costs for many of DLR options currently makes it difficult to economically justify deployment at distribution. However, one leading manufacturer of DLR systems infers that a lower cost package may soon be available for distribution applications.
Interaction with Other Smart Grid Technologies	Achieving the full benefits of DLR will also require deployment of Smart Inverters with communication and curtailment protocols, along with regulatory/market protocols that allow such curtailment. Could also be integrated with DA controllers in substations, etc.
Barriers to Deployment	In general, DLR by itself offers minimal benefits to high penetration PV deployment, unless DLR is combined with use of smart PV inverter communication, and remote dispatch or curtailment capabilities that could be used to keep the variable PV output level within the dynamic conductor rating of oversaturated feeders.. Furthermore, new market/regulatory protocols would be needed to allow such PV dispatch/curtailment.
Potential Solutions to Barriers	Adopt suitable market/regulatory protocols related to PV inverter communications, dispatch and curtailment – for use in conjunction with DLR technology.

Smart Grid Technology	***Forecasting Tools for Intermittent Distributed Generation***
General Description	Forecasting tools that make use of sensors, weather data, statistical and software models can help utilities plan for fluctuations in renewable DG output, through which actions can be taken to mitigate power quality issues on the distribution system.
How it Impacts DG Deployment	Different time-frames are possible depending on the specific DG operating issue to be addressed. Can potentially be used for automatic DG dispatch, curtailment or shutoff algorithms (shorter time-frame, e.g. minutes or less) or for longer-term operational planning options (e.g. next day or coming hours) that could be implemented through operator or resource scheduler actions.
Cost to Deploy *(e.g., per typical feeder)*	The cost depends on the size of the area to be addressed, the number of measurement points within the system, the level of granularity desired and whether actions will be implemented automatically or manually. A fully automated system that includes a wide range of sensors and software capabilities might start at around $1 million for a small (e.g., single substation) area; a large area implementation could cost several million with roughly a 20% annual O&M cost. Non-automatic systems that relay on operator/dispatcher actions can be installed at much lower cost.
Potential for Deferring Distribution Upgrades	Varies as a function of the type of DG and the regulatory/market rules related to dispatch and curtailment. This technology is primarily an enabler and support/decision making tool for the system operator/dispatcher, unless it is automated and integrated with other applications such as distribution automation and/or smart PV inverters.
Current Status of Technology Deployment	Several forecasting tools are available in the market and vary in level of capability. Many of the current forecasting tools are more focused for wind generation rather than solar which requires greater granularity. Several software packages on the market forecast both wind and solar insolation, but will likely need customization and sensors to achieve the granularity required for distribution systems (e.g., these could be targeted in problem areas or areas with the highest PV deployment levels).
Interaction with Other Smart Grid Technologies	This technology is dependent on the type of renewable DG, and the mitigation measures available under applicable regulatory/market protocols. Short-time frame algorithms require smart PV inverters with communications and control capabilities. Can also work in conjunction with voltage control equipment, DA, distributed storage or potentially load

	control to prevent power quality issues and overloads.
Barriers to Deployment	The development and deployment of this technology to date has primarily been at the transmission (wider area level) and use at the distribution system is still evolving. Broader forecasting models and weather forecasting tools currently exist for wider geographic areas but may not be granular enough for a feeder or substation level applications; however, this technology is improving rapidly. The regulatory/market rules currently in place in California may also limit deployment.
Potential Solutions to Barriers	Adoption of suitable regulatory/market protocols to support the types of mitigation actions (e.g., PV scheduling, curtailment, or shut-off) needed to make effective use of such forecasting tools.

Smart Grid Technology	***Real-time Utility Monitoring & Curtailment of PV Inverters***
General Description	Individual PV inverters on the distribution system in California – both retail (behind the meter) and wholesale (connected into the utility system) – are generally exempt under CPUC Rule 21 from real-time monitoring or curtailment by the host utility. However, real-time monitoring (telemetry) is required by Rule 21 and some California municipal utilities on projects above 1 MW. Wholesale PV projects are currently responsible for the costs of any distribution system upgrades needed to maintain acceptable grid reliability and power quality, which often results in delay or cancellation of such PV projects. Retail PV (net metering) customers are currently exempt from the cost of such upgrades, so the utility (and thus ratepayers) pay for any upgrades to mitigate reliability impacts from retail PV. A number of new distribution smart grid options would become feasible in California if real-time utility monitoring and curtailment capability were to be implemented on distributed PV inverters on a wide scale in California (e.g., similar to inverter requirements under grid rules in Germany). As RPS levels continue to increase the need for remote monitoring and control of PV inverters will be even more critical under abnormal system operating conditions.
How it Impacts DG Deployment	Widespread introduction of smart inverter requirements in California could significantly ease the integration of new distributed PV and higher RPS levels in by providing a means of maintaining reliability and power quality under all load levels and operating conditions including extreme system demand levels (e.g., very high or very low) and during unplanned system operating conditions. However, PV inverter output under normal system conditions would generally be unaffected. In any case, PV customers could be compensated for any curtailments that are required for grid reliability.
Cost to Deploy *(e.g., per typical feeder)*	Most modern PV inverters have built in capability for remote monitoring and/or curtailment functionality via serial communication, so the real incremental cost for remote monitoring and curtailment is related to installing the telecommunication infrastructure to get the data or commands transferred between the utility control center (or distribution automation controller) and the remote PV inverters. Depending on the telecom technology used, these costs could run hundreds (or even thousands) of dollars per PV inverter regardless of the inverter size (i.e., they are not expressible in $/kW terms.)
Potential for Deferring Distribution Upgrades	Very high, especially if used in conjunction with other smart grid technologies. Utility system capital cost savings could easily be orders of magnitude greater than the incremental telecommunication costs. However, the cost of associated smart grid technology options that can make use of such remote curtailment and monitoring features would also need to be considered.

Current Status of Technology Deployment	While substantial progress has been made in remote communication and command technology, there is still a need for a standardized communication media and protocol. Several communication media options such as Radio-based mesh network, cellphone networks, fiber optic, internet or leased wide area network are being used. Similarly several communication protocols such as DNP3, ModBus, SEP2 and web services are being used. A single information model such as IEC 61850 must be used to realize interoperability and thus ensure system security. In addition with higher solar penetration, cyber security must also be an integral part of the communication framework. The proposed new version of IEEE 1547 (i.e., P1547A) retains the existing inverter voltage and frequency ranges and tripping requirements as the "default", but does allow utilities and regulatory agencies to implement broader requirements.
Interaction with Other Smart Grid Technologies	A number of other potential smart grid technologies (e.g., advanced distribution automation, etc.) depend on remote PV monitoring and/or curtailment capability as well as other non-PV related measures. However, PV inverter curtailments should be invoked by such smart grid technologies only after other automatic mitigation measures are exhausted (e.g., voltage regulator and shunt capacitor operation, etc.)
Barriers to Deployment	The most significant barriers are regulatory/market related issues and the cost of the telecommunications. These costs may be a key factor in deciding what range of PV inverter ratings in California should be required to have such capabilities. In addition, the industry is still developing common standards for related communication/inverter technical protocols which could slow implementation in the near term until such standards are fully adopted. There is reluctance by utilities to use less reliable, lower cost options for communicating with inverters and the cost of highly reliable communication for small DG can be prohibitive. Current trajectory seems to be heading towards developing reliable communication with all inverter sizes; however this is going to take time and effort.
Potential Solutions to Barriers	Implement appropriate revisions to CPUC Rule 21 (and municipal utility rules) in conjunction with possible compensation provisions for any necessary PV inverter curtailments. Some compromise between DG behavior under remote utility supervision and DG behavior in isolation is likely to be needed in order to utilize the advantages of smart inverter applications.

Smart Grid Technology	***Smart PV Inverters with Local Voltage Control***
General Description	Legacy PV inverters operate in only one dimension – they only produce real power (kW) output. Smart "Two Quadrant" PV Inverters with local voltage control are also capable of injecting and absorbing reactive power into the grid – along with kW – in order to help control voltage. This capability allows the inverter to mitigate undesirable excessive voltage rise during low loading conditions or voltage sag during high loading periods. As PV penetration levels increase the use of two quadrant PV inverters with local voltage sensing and control would improve feeder voltage control by injecting reactive power support where it's most needed on the feeder.

How it Impacts DG Deployment	PV inverters with local voltage sensing and control allows for improved voltage profile without the need for installing expensive dynamic var support devices such as STATCOMs or DVARs. Effective utilization of two quadrant inverters to control voltage improves reliability/power quality and significantly reduces the frequency of feeder regulator tap changer operations leading to longer equipment life.
Cost to Deploy ***(e.g., per typical feeder)***	The incremental cost to add this capability on new PV inverters would be mostly driven by the need to add additional MVA capacity to the inverter to produce kVAR in addition to kW. On a new inverter this incremental cost will vary from $0.10/Watt to $0.20/Watt as compared to a legacy inverter. On smart inverters with two-quadrant capability, utility specified inverter voltage control mode and set points can pre-set at installation or can be adjusted via remote signal from the utility. The latter approach requires telecommunications to be installed between the utility and the inverter, and the cost of such telecommunications can run in the hundreds (or even thousands) of dollars per inverter.
Potential for Deferring Distribution Upgrades	Two quadrant inverters could potentially defer some critical upgrades to the distribution systems, such as upgrade or replacement of load tap changing transformers and feeder voltage regulators, or the need for deploying dynamic VARs devices such as STATCOMs, DVARs, etc.
Current Status of Technology Deployment	Two quadrant inverters are being deployed routinely at the transmission level for utility scale PV and wind generation projects, but there has been minimal deployment to date at distribution level. IEEE and UL standards for smaller inverters do not currently provide for local voltage control. However, a pending revision of IEEE 1547 (i.e., "P1547A") is expected to allow for DG inverters to actively participate in regulating the local voltage, subject to coordination of such requirements with the utility.
Interaction with Other Smart Grid Technologies	Two quadrant inverters are software driven equipment and can facilitate fast interaction with other smart grid technologies such as distribution automation systems. Most of the equipment manufacturers have incorporated industry standard protocols and interfaces to communicate with smart grid devices.
Barriers to Deployment	Release of the new versions of IEEE and UL standards for smart DG inverters may still be several years away which is a deterrent to adoption of these design features by inverter manufacturers. While inverter manufacturers want the requirements laid out for them, someone has to be first to implement and demonstrate that they work without unexpected side-effects on the distribution system before widespread adoption. Being first is undoubtedly an expensive research task for the equipment manufacturer, but if a large enough market requires this then they may invest. RD&D funding from the utility sector is needed to support this research. Although there are some incremental costs for two quadrant capability, as the demand for these features grows we predict a steady decline in associated inverter's cost. Furthermore, if all manufacturers are required to implement some minimum VAR generation capacity, then any perception of a competitive disadvantage of implementing it disappears (level playing field).

Potential Solutions to Barriers	Implement revised CPUC Rule 21 requirements for voltage control on distributed PV inverters over a certain rating threshold (e.g., over 5kW). Given that California is on the forefront of renewable integration, this will provide a clear incentive to manufacturers and standards groups to adopt these changes in inverter designs and standards. The earlier the CPUC can define such requirements through Rule 21, the sooner certified products will be available on the market. Technical issues can be addressed through pending changes to inverter standards, and could include Q/V ("droop") control similar to the German (BDEW) MV directive.[1] A coordinated automatic voltage control strategy could be used in lieu of locale sensing and control in order to resolve any possible conflicts with other voltage regulators. Additional telecommunications will be required to instruct PV Inverters whether or not to operate in a local voltage control mode.
[1] Technical Guideline, Generating Plants Connected to the Medium-Voltage Network, Guideline for generating plants' connection to and parallel operation with the medium-voltage network, June 2008 issue, Paragraph 2.5.4 "Reactive power", www.bdew.de.	

Smart Grid Technology	***Smart Inverters with Ride Through Capability***
General Description	Per IEEE 1547 distributed PV inverters are required to trip within 2 seconds following loss of utility source voltage, as well as for utility system frequency or voltage outside of a specified bandwidth. The basis for this requirement is the concern that at some local level the DG and nearby loads may happen to be equal at the time a disconnection from the utility occurs. This could lead to an unintentional "power island" that could be a safety risk to utility personnel or customers. The 2 second grace period was defined to allow standard distribution-system recloser equipment to reconnect the isolated distribution segment to the utility without "clashing" with a DG-powered island. This standards requirement gave priority to local safety concerns based on the assumption of low levels of PV inverter deployment and did not take into account the detrimental reliability impacts that can occur if massive numbers of distributed PV inverters simultaneously trip off line during short-term voltage or frequency swings on the utility system. Tripping of distributed inverters is an appropriate action if there is a fault is on the feeder that the PV connects to, but may be undesirable if the abnormal conditions are due to remote faults or reflect generation imbalances on the transmission system. In comparison, most renewable generators connected at transmission voltages are required to ride through such dips in voltage/frequency and remain on line. Extending this "Ride Through" criterion to distribution level PV would eliminate unnecessary PV inverter trips and potential degradation of utility system reliability. However, since local safety concerns cannot be ignored, some strategy for distinguishing local from remote grid events must be implemented if system stability concerns are to be addressed with "Ride Through".

How it Impacts DG Deployment	High levels of legacy PV inverters without ride through capability can cause voltage or frequency instability when large amounts of PV simultaneously trips offline due to a system voltage or frequency deviation such as those that sometimes originate from operating conditions at the transmission level. Adding ride through capability would mitigate this risk by enabling DG inverters to continue providing power to the system such during such deviations. SG communication that allows the utility to remotely keep the generation on-line longer for such conditions is desirable for overall system stability, but it still must be implemented in a safe manner. With smart inverters the utility could have the option to tell the DG when the problem is local (e.g., need to trip inverter quickly for safety) or system-wide (e.g., need to ride-through).
Cost to De ploy *(e.g., per typical feeder)*	The primary cost involved in implementing this smart inverter option is the associated communications, which can run hundreds (or even thousands) of dollars per inverter. Also, a small incremental cost (e.g., up to $10/kw at the residential level) would be incurred to include ride through in the specifications for the actual inverters for new PV projects. Larger costs would be involved in retrofitting existing PV projects with new inverters that have ride through capability (e.g., as much as $200/kW at the residential level). However, in either case, these incremental inverter costs could be small compared to the resulting net benefit in utility capital cost deferral. And the incremental costs would be far less per kW at the commercial and utility-scale level PV inverter level.
Potential for Deferring Distribution Upgrades	Would have a beneficial impact on ability to achieve aggregate statewide RPS targets above 33% by mitigating potentially serious reliability impacts at balancing area level. This smart inverter technology would prevent widespread tripping of distributed PV inverters occurs during most voltage or frequency deviations on the bulk power system. If such tripping occurs it can de-stabilize the bulk power system.
Current Status of Technology Deployment	The technology has been fairly widely deployed at transmission levels in the US, but there is minimal deployment to date at distribution system level since IEEE and UL standards for smaller inverters do not currently provide for ride through and issues related to the remote communication requirements still need to be resolved. Adoption of P1547A would allow utilities and regulatory agencies to implement such smart inverter requirements, but P1547A alone does not require such features.
Interaction with Other Smart Grid Technologies	Inverter ride through capability is compatible with the other types of smart inverter PV capabilities currently being deployed and/or expected to be deployed in the future on distribution.
Barriers to Deployment	Release of the new versions of IEEE and UL standards for smart DG inverters may still be several years away, which is a deterrent to adoption of these design features by inverter manufacturers. Also, the preferred method for reverting to current anti-islanding ("tripping") mode of inverter operation is still the subject of much debate, along with the issue of what levels of communication system reliability and security are required. This will need to be thoroughly considered by California utilities and regulators as the costs to implement it can be significant depending on the communication technology used. On the other hand the reduction in PV outage times due to fewer inverter shutdowns for remote faults will increase their annual energy production and revenue stream.
Potential Solutions to Barriers	Implement revised CPUC Rule 21 requirements for FRT on distributed PV inverters over a certain rating threshold (e.g., over 5kW), including requirements for when to revert to inverter self-detection of islanding ("tripping") mode. Given that California is on the forefront of renewable integration, issuing revised Rule 21 requirements will provide a clear incentive to manufacturers and standards groups to adopt these changes in inverter designs and standards. The earlier the CPUC can define such requirements through Rule 21, the sooner certified products will be available on the market.

Smart Grid Technology	*Smart Inverter With Battery Storage for Ramp Control*
General Description	Four quadrant inverters are bi-directional and can absorb or inject both real and reactive power into the grid if installed in conjunction with local battery storage provisions. Such systems are collectively referred to as a Battery Inverter System (BESS). Passing cloud cover or other metrological conditions can cause rapid ramps in the real power output of the inverters. Such repetitive ramps can cause unacceptable levels of voltage flicker on the distribution system. Four quadrant PV inverters with ramp control mitigate this situation by gradually ramping up or down the active power generation in conjunction with the solar irradiance changes. Battery/charger size requirements are modest since the charge/discharge cycles tend to be rather short (e.g., 15 minutes or less).
How it Impacts DG Deployment	Four quadrant inverters could effectively smooth the load and voltage profile of a feeder by injecting or absorbing real and reactive power allowing greater levels of PV integration without causing power quality issues. With increased penetration of PV inverters with ramp rate control, the Balancing Area would also see improved frequency regulation.
Cost to Deploy ***(e.g., per typical feeder)***	There would be an additional cost for the storage system, in addition to the inverters. Depending upon the control philosophy, the storage system and the inverters would need to have some additional supervisory controls to coordinate the response of the battery in conjunction with the inverters. This could lead to additional cost. Based on a 15 minute storage capability for systems rated between 100 kW-1,000 kW, the installed cost (excluding interconnection facilities) with a bi-directional Four quadrant inverter is in the range of $1,000/kW to $1,500/kW. For smaller PV projects, the cost/kW can be several times as high.
Potential for Deferring Distribution Upgrades	Four quadrant inverters with ramp control could defer some critical upgrades other costlier distribution system upgrades, such as reconductoring and dynamic voltage support. Cost-benefit analysis should be done on a case by case basis.
Current Status of Technology Deployment	Utilizes available battery technology. Numerous PV ramp smoothing applications have been deployed worldwide. The application is expected to grow more widespread as RPS levels grow and PV inverters cause increasing impacts on utility system voltages during transient cloud cover events. The CPUC has approved construction and rate-basing of several utility scale pilot projects and .SCE has added the requirement to its contracts with wholesale PV developers.
Interaction with Other Smart Grid Technologies	Four quadrant inverters are primarily software driven equipment and can facilitate fast interaction with other smart grid technologies such as distribution automation systems. Most inverter equipment manufacturers have incorporated industry standard protocols and interfaces to communicate with smart grid devices.
Barriers to Deployment	BESS batteries are still relatively expensive and have a limited life cycle and replacement will be periodically required during the normal life of the PV project, increasing O&M costs. However, as battery technology evolves the costs will drop and life cycles will increase. The CPUC's current R.10-12-007 proceeding has identified a number of barriers.

Potential Solutions to Barriers	The CPUC's current draft rulemaking in R.10-12-007 calls for 1,325 MW of storage projects (approximately half on distribution) to be procured by the three IOU systems from 2014-2020. The utilities and CEC should also support battery industry research though PIER and EPIC funding to improve the likelihood of a near term technological break-through which could bring the cost for BESS down and extend battery life cycle, thus reducing O&M costs. Continued pilot and demonstration projects will also build experience with energy storage in California.

Smart Grid Technology	***Smart Inverter With Peak-Reducing Battery Storage***
General Description	Four quadrant inverters are bi-directional inverters that can absorb or inject both real and reactive power into the grid if installed in conjunction with local battery storage provisions. Such systems are collectively referred to as a Battery Inverter System (BESS). On many distribution feeders in California, especially those with a high proportion of residential loads, the peaks in the hourly demand curve and the diurnal PV output curve are time shifted (non-coincident). Four quadrant inverters, in conjunction with suitable longer-term energy storage capability, can be used to charge the batteries during non-peak/shoulder peak hours and discharge the batteries during peak hour(s) thereby effectively reducing the net peak demand
How it Impacts DG Deployment	Reduces the magnitude of PV injection during non-peak demand hours on individual feeders, thus reducing the overall utility system voltage and reliability impacts related to PV operation. Circumvents or defers other types of distribution system upgrades that may be needed to mitigate impacts that the connected PV capacity has on the distribution system, especially in high RPS scenarios.
Cost to Deploy *(e.g., per typical feeder)*	Peak reducing storage requires significantly larger battery capability than ramp control applications, leading to larger upfront capital investment in the BESS facility. Based on a 2 Hour storage capability for systems rated between 100 kW-1,000 kW, the installed cost (excluding interconnection facilities) with a four quadrant inverter and peak shifting storage is in the range of $2,000/kW to $3,750/kW (installed cost, excluding interconnection). For longer storage intervals or smaller PV projects, the cost/kW will be higher.
Potential for Deferring Distribution Upgrades	Has potential for deferring distribution upgrades on selected feeders, but benefit-cost analysis must be determined on case by case basis. Not likely to be cost effective on a widespread basis in California. Can also provide production cost savings, depending on the efficiency of the BESS and respective energy market prices during the charging and discharging hours.
Current Status of Technology Deployment	Utilizes available battery technology, but currently expensive due to amount of energy storage required. Best suited in the near term to certain niche applications (e.g., feeders that peak later in day), but potential for more widespread application will grow if battery costs drop over next decade. SMUD has installed a small demo system. The CPUC has approved construction and rate-basing of several utility scale pilot storage projects that could potentially be used for peak shifting.

Interaction with Other Smart Grid Technologies	Existing controls and communication technologies developed using industry standard control and communication protocol should allow smooth interaction with other smart grid technologies. If peak shifting storage capability is installed in conjunction with PV inverters that have fault ride through (FRT) capability, the combination can provide an even more reliable offset to feeder peak demand.
Barriers to Deployment	The CPUC's current R.10-12-007 proceeding has identified a number of barriers to deployment of distributed storage. In addition to those barriers, we note that due to the duration of the charge-discharge cycles required in the peak reducing application larger battery storage (kWh) capability is generally required. As a rule of thumb, a kWh rating equal to at least 200% of the PV inverter kW rating (e.g., 2 kWh/kW installed) is required for this type of application. This size of BESS is economically infeasible at the PV inverter location unless the PV project is compensated in some way for the resulting benefit(s) and it's currently unclear how the compensation should be structured. If the BESS is also designed to be sectionalized from the utility system, in order to operate as part of an islanded customer microgrid , a visible open point (i.e., switching device) will be needed between the utility and the BESS island/microgrid so that the remote utility system operator and field personnel both have clear real-time indication of the operating mode of the BESS for safety purposes before reclosing the connection to the utility system.
Potential Solutions to Barriers	The CPUC's current draft rulemaking in R.10-12-007 calls for 1,325 MW of storage projects (nearly half on distribution) to be procured by the three IOU systems from 2014-2020, which may include peak reducing capability in some cases. The utilities and CEC should also support battery industry research through PIER and EPIC funding to improve the likelihood of a near term technological break-through which could bring the cost for BESS down and extend battery life cycle, thus reducing O&M costs. Continued pilot and demonstration projects will also build experience with energy storage in California.

Smart Grid Technology	***Smart Inverter for Three-Phase Asymmetrical Phase-Balancing***
General Description	Distribution feeders often have a significant imbalance between the loading on different phases due to the preponderance of single-phase customer loads found on most feeders. This creates unused capacity on the lightly loaded phases. It is possible to design 3-phase PV inverters capable of injecting phase currents that are anti-proportional to the phase imbalance of the receiving 3-phase system as measured at a monitored point along the 3-phase feeder beyond the point of common coupling.
How it Impacts DG Deployment	Increases deliverability on 4-wire distribution systems where imbalance limits total power throughput because of excessive neutral return current. The constraint can be neutral conductor rating or ground-current relay setting. On 3-wire primary distribution systems, the benefit would be avoiding overheating of substation transformers due to imbalance caused circulating currents. By balancing the 3-phase current there would be reduced risk of unplanned load loss due to substation transformer overload and this in turn should extend transformer life.

Cost to Deploy *(e.g., per typical feeder)*	Incremental cost increase for up-sizing to meet the minimum 3-phase inverter delivery requirement under maximum inter-phase imbalance. For planning-level unit cost estimating, the cost impact is increase in inverter price proportional to the MVA up-sizing added to enable this capability. The MVA requirement will depend on whether the inverter is installed on a 3 wire or 4 wire distribution system. If 3 wire, the incremental cost may be on the order of 25-33%. If 4 wire, incremental cost could be 50-100% depending on the amount of phase imbalance and ground current requirement.
Potential for Deferring Distribution Upgrades	Directly translates into potential to deferral of distribution upgrades, by permitting use of previously untapped incremental 3-phase capacity which is restored by balancing loading/current on the three phases of the feeder. Conventional methods are also available to rebalance phase loadings, but may be costlier. Use of asymmetrical phase balancing inverters offers another alternative for evaluation.
Current Status of Technology Deployment	No known installations to date, but inverter manufacturer Parker Hannifin has provided a quote to at least one California IOU to add this feature on a 2 MW battery project Four Quadrant inverter.
Interaction with Other Smart Grid Technologies	The system performance attributes impacted by injecting balancing currents should not interfere with the control objectives and implementations of other circuit-connected devices.
Barriers to Deployment	New inverter feature – not generally offered today by inverter manufacturers. However, this capability has been quoted by one manufacturer and discussed with at least two more. In order to count this capability as a firm-capacity offset to increasing conductor rating, the resource providing the input to the inverter may need to be dispatchable (e.g. energy storage, micro-turbine, etc.), thus limiting the opportunities to deploy this form of grid support. However, there may be current policy issues related to compensating a 3rd party (DG owner) for solving a utility constraint beyond the PCC.
Potential Solutions to Barriers	Demo/Pilot the capability with a participating supplier and host utility. For utility scale projects consider rate-basing the added inverter cost if it can be used to improve the deliverability of power through the existing utility system and thus defer upgrading. Consider potential regulatory structure for new financial incentives to DG owners who provide such phase balancing and defer utility system upgrades.

Smart Grid Technology	***Solid State Line Voltage Regulators***
General Description	Solid state line voltage regulators can prevent power quality issues and protect customers from voltage spikes or dips by providing rapid response to changes in feeder voltages related to PV inverter output. Legacy voltage regulators utilize electro-mechanical tap changing to adjust feeder voltages which can take many seconds to respond to voltage changes on the feeder. Therefore, while they may be effective in managing slower voltage changes due to diurnal PV inverter ramps, legacy voltage regulators are not effective during rapid transients such as those related to cloud passage. However, solid state thyristor-controlled voltage regulator technology can respond almost instantaneously to PV inverter output changes.

How it Impacts DG Deployment	Solid state regulator technology can mitigate power quality problems due to sudden changes in output from PV inverters without incurring the cost of major feeder upgrades that may otherwise be required. While this is especially important to sensitive or remote loads, managing power quality for all customers on a feeder must be maintained within acceptable limits regardless of the extent of PV inverter deployment on the feeder. Solid state regulators could fill this need.
Cost to Deploy *(e.g., per typical feeder)*	Cost depends on the commercial maturity of the technology as well as the kVA size and voltage level of the installation. Current cost estimates are in the ballpark of $100/kVA (single-phase unit) to $200/kVA (3-phase unit), but costs are expected to decrease significantly over the long-term as the technology becomes more commercially developed.
Potential for Deferring Distribution Upgrades	Not currently a cost effective option for most feeder applications. However, there may be niche applications that can be economically justified such as remote PV inverters with voltage sensitive customers located nearby. Widespread deployment is not likely to be cost effective for years to come.
Current Status of Technology Deployment	At this time it appears the technology is limited to use at distribution secondary voltage levels (e.g., for customers with critical voltage needs). With future evolution of this technology the range of available ratings should increase and allow the technology to be deployed at primary voltage levels on utility feeders. However, the timeline for this evolution is unknown.
Interaction with Other Smart Grid Technologies	The technology can be integrated with other SG technologies, including advanced distribution automation and advanced PV inverters. However, the overall voltage control strategy needs to be carefully analyzed in each application.
Barriers to Deployment	Very expensive compared to conventional voltage regulators at this time for primary feeder applications and the limited range of available ratings may inhibit widespread deployment for years to come at primary feeder voltage levels.
Potential Solutions to Barriers	A careful assessment of long-term distribution expansion options and asset management strategies would be needed to demonstrate the tradeoffs of using this technology versus other voltage regulation options at high RPS levels.