ATTACHMENT

Planning Assumptions and Scenarios for use in the CPUC 2014 Long-Term Procurement Plan Proceeding and CAISO 2014-15 Transmission Planning Process

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1 Introduction

California Public Utilities Commission (CPUC) Energy Division staff prepared this document with collaboration from staff of the California Energy Commission (CEC) and California Independent System Operator (CAISO). The staff of the CPUC, CEC, and CAISO worked together to design the scenarios set forth in this document, discussed alternative sets of assumptions for each scenario, and for the preferred resources, discussed how alternative assumptions interact with baseline demand forecasts. CEC staff provided analysis to the CPUC for development of Renewable Portfolio Standard (RPS) project portfolios. The staff of the CPUC, CEC, and CAISO proposes these assumptions and scenarios for use in resource planning studies in the 2014 Long Term Procurement Plan (LTPP) proceeding and 2014-15 CAISO Transmission Planning Process (TPP). The assumptions were crafted to serve as reasonable, transparent building blocks of the proposed scenarios. The scenarios were created to focus on key policies that will impact the long-term planning of the state's electricity resources and infrastructure.

1.1 Terminology

Acronym	**Definition**
CPUC	California Public Utilities Commission
CEC	California Energy Commission
CAISO	California Independent System Operator
ARB	Air Resources Board
SWRCB	State Water Resources Control Board
TEPPC	Transmission Expansion Planning Policy Committee
IOU	Investor Owned Utility
POU	Publicly Owned Utility
LSE	Load Serving Entity
PG&E	Pacific Gas and Electric
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
1-in-10	1-in-10 year weather peak demand forecast
1-in-5	1-in-5 year weather peak demand forecast
1-in-2	1-in-2 year weather peak demand forecast
AB	Assembly Bill

CED	California Energy Demand Forecast (CEC)
DSM	Demand Side Management
CHP	Combined Heat and Power
GWh	Gigawatt Hour
IEPR	Integrated Energy Policy Report (CEC)
LCA	Local Capacity Area
LCR	Local Capacity Requirement
LTPP	Long Term Procurement Plan (CPUC)
MW	Megawatt
NQC	Net Qualifying Capacity
OTC	Once Through Cooled
PTO	Participating Transmission Owner
RNS	Renewable Net Short
RPS	Renewable Portfolio Standard
SGIP	Self-Generation Incentive Program
TPP	Transmission Planning Process (CAISO)

1.2 Definitions

- **Assumption**: a statement about the future for a given resource or resource type. For example, future load conditions are an assumption.
- **Scenario**: a complete set of assumptions defining a possible future world. Scenarios are driven by major factors with impacts across many aspects of loads and resources. For example, an increase or decrease in load would constitute a changed scenario since the impacts would potentially affect planning reserve margins, the amounts of renewables, and transmission needs.
- **Portfolio**: an important component of scenarios, portfolios are the mix of resources to be modeled, created as a result of applying the assumptions in a specific scenario. A high distributed generation scenario would have a different portfolio of resources than a low cost scenario. RPS portfolios refer specifically to the portfolio of supply-side renewable resources in a given scenario.
- **Sensitivity**: a variation on a scenario where one variable is modified to assess its impact on the overall scenario results. Different renewable portfolios, holding other assumptions constant, are an example of sensitivities.
- **Load Forecast**: refers to electricity demand, measured by both annual peak demand and annual energy consumption. Load forecasts are influenced by economic and demographic factors as well as retail rates.

- **Managed Forecast**: refers to a load forecast that has been adjusted to account for the impact of programs or expectations not embedded into the original forecast. An example is adjusting the California Energy Demand Forecast to account for energy efficiency programs not yet currently funded but with expectations for funding and specific programs in the future.
- **Probabilistic Load Level**: refers to the specific weather patterns assumed in the study year. For example a 1-in-10 Load Level indicates a high load event due to weather patterns expected to occur approximately once in every 10 years. The probabilistic load level primarily impacts annual peak demand (and other demand characteristics, such as variability) but does not significantly impact annual energy consumption.
- **Resource Plans**: refer to the need to build new resources or maintain existing resources from an electrical reliability perspective.
- **Bundled Plans**: refer to the three large Investor Owned Utilities' procurement plans established in compliance with AB 57 to determine upfront and reasonable procurement standards.

1.3 Background

The Long Term Procurement Plan (LTPP) proceedings were established to ensure a safe, reliable, and cost-effective electricity supply in California.[1] A major component of the LTPP proceeding addresses the overall long-term need for new system reliability resources, including the adoption of system resource plans.[2] These resource plans will allow the CPUC to comprehensively assess the impacts of state energy policies on the need for new resources. Based on these system resource plans, the CPUC shall consider updates to the Investor-Owned Utilities' (IOUs) bundled procurement plans with a focus on the IOUs' obligation to maintain electric supply procurement responsibilities on behalf of IOU customers.

The CPUC initiated the 2012 LTPP proceeding (R.12-03-014) by an Order Instituting Rulemaking issued on March 27, 2012.[3] The rulemaking's stated purpose is "to continue our efforts through integration and refinement of a comprehensive set of procurement policies, practices, and procedures underlying long-term procurement plans."[4]

To address the resource planning portion of the 2012 LTPP, CPUC Energy Division held public workshops and received comments from LTPP parties regarding standardized planning assumptions and scenarios to be studied in system reliability studies. On December 20, 2012, the CPUC adopted the set of assumptions and scenarios to be used in the 2012 LTPP system reliability/operational flexibility studies.[5]

[1] Pursuant to AB 57 (Stats. 2002, ch. 850, Sec 3, Effective September 24, 2002), added Pub. Util. Code § 454.5., enabling resources to resume procurement of resources. *See also* OIR 3/27/2012, Scoping Memo 1.

[2] *See* Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge, Rulemaking (R.)12-03-014, issued May 17, 2012.

[3] This proceeding follows R.10-05-006, R.08-02-007, R.06-02-013, R.04-04-003, and R.01-10-024, and the rulemakings initiated by the Commission to ensure that California's major investor-owned utilities (IOUs) resume and maintain procurement responsibilities on behalf of their customers.

[4] Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans, R.12-03-014, issued March 27, 2012, p. 1.

[5] Decision Adopting Long-Term Procurement Plans Track 2 Assumptions and Scenarios, D.12-12-010.

In 2013 as part of Track 2 of the 2012 LTPP, the CAISO and other LTPP parties conducted system operational flexibility studies based on the CPUC-adopted planning assumptions and scenarios. Concurrently with these activities, the CPUC considered local reliability needs in Tracks 1 and 4 of the 2012 LTPP. A Track 1 decision was issued in February 2013, but it is not likely that the Commission will issue a decision in Track 4 until early 2014.[6] The CPUC anticipates taking up system and local issues again with a refreshed set of planning assumptions and scenarios to be used in a new LTPP Rulemaking commencing in 2014. This document describes that refreshed set of planning assumptions and scenarios.

Because the CAISO utilizes similar assumptions in the annual Transmission Planning Process (TPP), there is a need to ensure that the infrastructure and procurement decisions are made on consistent assumptions. To coordinate the LTPP and TPP assumptions, the CAISO will use the assumptions proposed in this document in the development of the draft study plan for the 2014-2015 TPP, which will be issued for stakeholder comments in February 2014 and finalized in March 2014.

1.4 History of LTPP Planning Assumptions

Since the 2006 LTPP, the CPUC has worked to improve transparency and data access, and to streamline long-term procurement planning processes. The main effort of the 2008 LTPP was the creation of the *Energy Division Straw Proposal on LTPP Planning Standards.*[7] The 2010 LTPP took strides towards implementing that proposal, with adjustments based on party comments. CPUC Energy Division held several workshops in the summer of 2010, and in December 2010 the *2010 LTPP Standardized Planning Assumptions* were issued via a Joint Scoping Memo and Ruling.[8] Following a similar process of workshops and comments in 2012, the CPUC established LTPP planning assumptions for the 2012 LTPP that build upon the last four years of planning efforts to further improve the LTPP process.[9] This document refines earlier efforts and furthermore seeks to achieve transparent and consistent assumptions and coordination for resource planning activities across the energy agencies.

2 Guiding Principles

The Guiding Principles[10] for developing assumptions to be used and scenarios to be investigated in the

[6] Assigned Commissioner and Administrative Law Judge's Ruling Regarding Track 2 and Track 4 Schedules, R.12-03-014, issued September 16, 2013.

[7] *Energy Division Straw Proposal on LTPP Planning Standards,* http://docs.cpuc.ca.gov/published/Graphics/103215.PDF

[8] *See* Assigned Commissioner and Administrative Law Judge's Joint Scoping Memo and Ruling, issued December 3, 2012, http://docs.cpuc.ca.gov/EFILE/RULC/127542.htm

[9] Decision Adopting Long-Term Procurement Plans Track 2 Assumptions and Scenarios, D.12-12-010, issued December 20, 2012.

[10] *See* Assigned Commissioner's Ruling on Standardized Planning Assumptions, R.12-03-014, issued June 27, 2012.

upcoming 2014 LTPP Rulemaking build upon the 2012 LTPP:

A. **Assumptions** should take a realistic view of expected policy-driven resource achievements in order to ensure reliability of electric service and track progress toward resource policy goals.

B. **Assumptions** should reflect real-world possibilities, including the stated positions or intentions of market participants.

C. **Scenarios** should be informed by an open and transparent process. An exception is confidential market price data, which may be reasonably submitted with publicly available engineering or market-based price data checked against confidential market price data for accuracy.

D. **Scenarios** should inform the transmission planning process and the analysis of flexible resource requirements to reliably integrate and deliver new resources to loads.[11]

E. **Scenarios** should be designed to form useful policy information including tracking greenhouse gas reduction goals.

F. **Resource portfolios** should be substantially unique from each other.

G. **Scenarios** should inform bundled procurement plan limits and positions.

H. **Scenarios** should be limited in number based on the policy objectives that need to be understood in the current Long Term Procurement Plan cycle.

I. Resource planners including the CPUC, CEC, and CAISO should strive to reach agreement on planning assumptions, and commit **to transparent, consistent, and coordinated planning processes.**

3 Planning Scope: Area & Time Frame

The following assumptions and scenarios are created specifically with regard to the loads served by and the supply resources interconnected to the CAISO-controlled transmission grid and the associated distribution systems. The LTPP planning period is established as twenty years in order to consider the major impacts of infrastructure decisions now under consideration. While detailed planning assumptions are used to create an annual assessment in the first period (2014-2024), more generic long-term assumptions in the second period (2025-2034) are utilized to reflect heightened uncertainties around future conditions. The second period is designed to inform resource choices made today as well as shape policy discussions, and not to make authorizations of need in those years. The CAISO's TPP utilizes only the first ten-year period for its planning studies. This document supersedes the previous versions of assumptions and scenarios in this proceeding.

[11] Scenarios used by the CAISO Transmission Planning Process must meet the requirements in Section 24.4.6.6 of the CAISO's tariff. Scenarios developed in the LTPP process may inform the development of the CAISO's TPP scenarios to the extent feasible under the CAISO tariff and adopted by that organization.

4 Planning Assumptions

A description of assumptions is provided in this section. All values are reported in the 2014 Scenario Tool.[12]

4.1 *Demand-side Assumptions*

4.1.1 Base and Incremental Forecasts

Demand-side assumptions are either base forecasts or incremental to the demand forecast. Base values, such as the California Energy Demand Forecasts (CED),[13] are independent forecasts without ties to any other forecast. Incremental forecasts, such as Additional Achievable Energy Efficiency[14] (AA-EE, and formerly known as incremental uncommitted energy efficiency), are not embedded in the base forecast, but modify the base forecast to create a net or "managed" forecast. As an example, in the CED, which is treated as a base load forecast, the CEC embeds an amount of energy efficiency representing current codes and standards and established energy efficiency programs. AA-EE represents future expected energy or capacity savings from not yet established or funded programs, so AA-EE is considered an incremental forecast. Reducing the base load forecast by the AA-EE incremental forecast creates a managed load forecast. Assumptions originated from other state agencies, for example the CED, will not be re-litigated in this proceeding.

4.1.2 Locational Certainty

As California chooses to meet its electricity needs with increasing proportions of demand-side management resources, such as energy efficiency and customer-sited solar photovoltaic (PV) self-generation, it becomes increasingly important to accurately forecast the locations of these demand-side impacts in order to capture the benefits of these resources. Reliability studies in transmission-constrained local areas depend on these demand-side resources providing capacity value at least within the electrical areas forecasted, and preferably at specific busbar or substation locations if they are to offset local capacity requirements. Historically, demand-side resource forecasts lacked the locational certainty needed to contribute to local reliability. However, the current California Energy Demand set of forecasts, with its embedded demand-side resources and incremental AA-EE forecasts, is moving in the direction of greater locational certainty by providing impacts at the climate zone level. The CEC defines

[12] The 2014 Scenario Tool, version x.x will be posted to the following location in December, 2013: http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/ltpp_history.htm

[13] The CED: California Energy Demand 2014-2024 Forecast, posted December 2, 2013, http://www.energy.ca.gov/2013_energypolicy/documents/index.html#12112013

[14] The AA-EE forecast: Estimates of Additional Achievable Energy Savings, Supplement to California Energy Demand 2014-2024 Forecast, posted November 22, 2013, http://www.energy.ca.gov/2013_energypolicy/documents/index.html#12112013

15 climate zones in California.[15] Efforts are underway to further refine the locational certainty of all demand-side resources so that their benefit as substitutes for conventional generation can be realized in future planning cycles.

4.1.3 Load

The CEC's 2013 Integrated Energy Policy Report (IEPR) California Energy Demand (CED) forecasts serve as the source for the "managed demand forecast," consisting of a base load forecast coupled with an Additional Achievable Energy Efficiency (AA-EE) forecast (see subsection on Energy Efficiency below). The CED base forecasts include three load cases, "Low", "Mid", and "High", each factoring in variations on economic and demographic growth, retail electricity rates, fuel prices, and other elements. Each load case also has peak demand weather variants for example, 1-in-2 weather year and 1-in-10 weather year.

The 2013 IEPR CED accounts for transportation electrification given existing state policies. Development of policies that drive higher electrification growth is underway, and may include increased penetration of electric vehicles (EVs) across all vehicle types, and accelerated rail electrification. As the impacts of such policies become more certain, future planning assumptions will consider accounting for such policies by adjusting the base load forecast (e.g., changes in load shapes and higher annual energy consumption).

The CEC held a workshop on the revised CED base forecasts on October 1, 2013 and expects to adopt a final version on December 11, 2013. The CEC leadership, based on the IEPR record and in consultation with the CPUC and the CAISO, will jointly decide which load case (and associated peak demand weather variants) of the CED base forecasts shall be used for long-term infrastructure planning activities at the CPUC, CEC, and CAISO. The final decision will be documented in the 2013 IEPR final report, scheduled to be adopted at the CEC's January 15, 2014 Business Meeting.

4.1.4 Energy Efficiency

Energy efficiency forecasts shall be developed from the CEC's 2013 IEPR CED base forecasts and its supplemental Additional Achievable Energy Efficiency (AA-EE) forecasts. Each load case of the CED base forecasts contains an embedded EE component that will be paired with an AA-EE forecast scenario representing additional savings. CEC staff, with input from the Demand Analysis Working Group and in consultation with CPUC staff and CAISO staff, developed the AA-EE forecasts from the 2013 draft CPUC Potentials, Goals, and Targets Study.[16] The AA-EE forecasts include five savings scenarios, "Low", "Mid-Low", "Mid-Mid", "Mid-High", and "High". In general, the lowest savings scenario includes only the EE savings most certain to materialize while the highest savings scenario includes all EE potential including

[15] See p. 50 of http://www.energy.ca.gov/2013publications/CEC-200-2013-004/CEC-200-2013-004-SF-V1.pdf

[16] http://demandanalysisworkinggroup.org/documents/2013_08_16_ES_Pup_EE_Pot_final/2013_California_Energy_Efficiency_Potential_and_Goals_Study_Final_Draft_20130807.pdf

aspirational goals (e.g. emerging technologies). Planning studies performed for local reliability purposes require disaggregating savings forecasts down to the transmission-level busbar as well as estimates of the load-shape impacts of such savings. Such studies may need to account for uncertainties regarding busbar location and load-shape impacts.

Like the CED base forecasts, the CEC expects to adopt a final version of the AA-EE forecasts on December 11, 2013. The CEC, CPUC and CAISO are actively engaged in collaborative discussion on how to consistently account for reduced energy demand from energy efficiency in these planning and procurement processes. To that end, the CEC leadership, based on the IEPR record and in consultation with the CPUC and the CAISO, will jointly decide which scenario of the AA-EE forecasts shall be used for long-term infrastructure planning activities at the CPUC, CEC, and CAISO. The final decision will be documented in the 2013 IEPR final report, scheduled to be adopted at the CEC's January 15, 2014 Business Meeting.

For the purposes of calculating a statewide renewable net short to develop Renewable Portfolio Standard (RPS) portfolios, that calculation must also account for load reductions from incremental EE for all California Publicly Owned Utilities (POUs). That amount of incremental EE is derived from the forecast of POU incremental EE given in the CEC's 2011 demand forecast.[17] This demand forecast provides POU incremental EE estimates for 2015, 2020, and 2022. Using a linear fit analysis on these estimates, POU incremental EE savings were extrapolated to be 5,656 MW in 2024. This number is used to calculate the statewide renewable net short in 2024.

4.1.5 Solar Photovoltaics

The CED forecasts embed the impacts of initiatives such as the California Solar Initiative, as well as the effects of retail rates and programs such as Net Energy Metering. As such, the default forecast for behind-the-meter solar PV assumes no change from what the CED forecasts embed. Planning scenarios that model a higher penetration of behind-the-meter solar PV shall add an incremental forecast to the amounts embedded within the CED forecasts. The incremental forecast is created by subtracting the self-generation PV forecast in the CED "Mid" load case (mid PV penetration) from the self-generation PV forecast in the CED "Low" load case (high PV penetration).

4.1.6 Combined Heat and Power

The CED forecasts embed the impacts of initiatives such as the Self-Generation Incentive Program. As such, the default forecast for behind-the-meter combined heat and power (CHP) assumes no change from what the CED forecasts embed. Planning scenarios that model a higher penetration of behind-the-meter CHP shall add either a low or a high incremental forecast to the amounts embedded within the CED forecasts. ICF International conducted a policy analysis of CHP resources through 2030 and produced a report made available in July 2012.[18] The low incremental forecast is based on a CEC analysis of the "Base" forecast of on-site generation from the ICF report. The high incremental forecast

[17] http://www.energy.ca.gov/2011publications/CEC-200-2011-011/CEC-200-2011-011-SD.pdf

[18] *See* Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment – Consultant Report at

is based on a CEC analysis of the "High" forecast of on-site generation from the ICF report.[19]

4.1.7 Demand Response

The CED forecasts embed the impacts of non-dispatchable demand response (DR) programs, in other words, those impacts are treated on the demand-side. These programs are generally non-event-based and/or tariff-based and include TOU rates, Permanent Load Shifting, and Peak Time Rebate/Critical Peak Pricing. Dispatchable DR programs, which are generally event-based or emergency programs, are treated as supply resources.

There may be other effects that supply additional DR impacts, for example, a higher EV penetration could lead to charging models that can provide load shifting and frequency regulation by managing the charging times of an aggregate group of EVs. These speculative impacts are not accounted for at this time.

4.1.8 Energy Storage

Energy storage units shall be modeled as a supply-side resource, however, the assumptions about distribution and customer-side storage are described here. CPUC Decision (D.) 13-10-040 established 2020 targets of 425 MW for distribution-connected storage and 200 MW of customer-side storage. For the purposes of the planning assumptions, there is no expectation that distribution and customer sited storage will be deployed and operated in a manner that provides capacity value at times of system stress, nor is there any information about where these resources will be deployed. Therefore, the 625 MW storage target described above will only be modeled in zonal production cost simulations but will not count as capacity in power flow studies. At this time assumptions will need to be made with respect to the profile for the storage and how it will affect the load shapes within the zonal production cost model. For example, one factor to consider is that some types of customer-side storage may not be grid-connected and only store customer-side generation. Note that it is assumed the energy storage described here is exclusive and incremental to any similar technologies that are accounted for as non-dispatchable DR (e.g. Permanent Load Shifting) embedded within the CEC's CED forecasts.

4.2 Supply-side Assumptions

All supply-side resource assumptions are solely for planning purposes. Inclusion or exclusion of a specific project or resource in the planning cycle has no implications for existing or future contracts. To the extent a specific forecasted resource is not available, the analysis assumes an electrically equivalent resource will be available.

All supply-side resources should be categorized either as within a specific local area, as a generic system

http://www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002-REV.pdf

[19] Straight-line interpolation for intervening years between the "Base" case and "High" case target years identified in the ICF report

resource, or as out-of-state. Resources should be accounted for in terms of their most current net qualifying capacity (NQC) for purposes of constructing loads and resources tables. In the absence of a NQC, a resource's expected NQC should be based on its expected installed capacity adjusted for the peak impact value of that technology type. To the extent that NQC accounting methodologies change in the future, those changes should be reflected in LTPPs subsequent to the current LTPP. For variable resources, methods that can forecast production based on a variety of conditions are preferred to utilizing single point or year assumptions. In addition, generation profiles of variable resources are used in the production simulation model analysis. These profiles may also be used in TPP studies to determine output levels of these resources corresponding to the load levels (peak, off-peak, partial peak, and light load base cases) of the applicable studies. The Effective Load Carrying Capacity (ELCC) method of assigning capacity value to wind and solar resources is expected to become available for the next cycle of developing planning assumptions. At this time, the degradation of resource production over time is not accounted for in these planning assumptions.

4.2.1 Existing Resources

The capacities of existing resources shall be the August NQC values found in the 2014 Resource Adequacy compliance year NQC list.[20] The CAISO and CPUC both publish these lists annually on their respective websites. Renewable resources are addressed separately below.

4.2.2 Conventional Additions

The default values for conventional resource additions 50 MW or larger derive from the list of power plant siting cases maintained on the CEC website.[21] The default values for conventional resource additions smaller than 50 MW derive from other databases maintained by the CEC. The CEC updates these lists several times per year. A power plant project shall be counted if it (1) has a contract, (2) has been permitted, and (3) has begun construction. A power plant project that does not meet these criteria may be counted if the staff of the agency with permitting jurisdiction expects the project to come online within the planning horizon.

4.2.3 Combined Heat and Power

Resources identified here export electricity to the grid. The Demand-side Assumptions section discusses resources that provide on-site energy. The default forecast for exporting CHP assumes no net growth. Planning scenarios that model a higher penetration of exporting CHP shall add either a low or a high incremental forecast of growth. ICF International conducted a policy analysis of CHP resources through 2030 and produced a report made available in July 2012.[22] The low incremental forecast is based on a

[20] *See* Resource Adequacy Compliance Materials at http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/ra_compliance_materials.htm

[21] http://www.energy.ca.gov/sitingcases/all_projects.html

[22] *See* Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment – Consultant Report at

CEC analysis of the "Base" forecast of exporting CHP from the ICF report. The high incremental forecast is based on a CEC analysis of the "High" forecast of exporting CHP from the ICF report.[23]

4.2.4 Energy Storage

CPUC Decision (D.)13-10-040 established a 2020 target of 700 MW for transmission-connected energy storage units. The 50 MW that CPUC Decision (D.)13-02-015 ordered SCE to procure is subsumed within the 2020 target. It is not double counted with demand-side storage as the target must be met regardless of which category (transmission-connected, distribution-connected, or customer-connected) the 50 MW eventually falls in. No further growth in storage is assumed post 2020. Unlike demand-side storage, locations can be reasonably projected for transmission-connected storage, as these resources will likely interconnect to the system near transmission substations. Moreover, transmission-connected storage will likely be operated in a manner that adds to system and local reliability. Therefore, the 700 MW storage target described above will serve as the default assumption to be modeled in all planning studies.

According to D.13-10-040, the maximum size of storage projects that count towards the target is 50 MW but there is no overall cap. The decision also notes that some resource types such as Concentrating Solar include storage and the capacity value of this storage counts toward the 2020 target if the resource comes online by 2020.

4.2.5 Demand Response

Dispatchable demand response (generally event-based and emergency programs) shall be accounted for as a supply-side resource. The most recent Load Impact reports[24] filed with the CPUC serve as the default assumption. The Load Impact reports are published annually on April 1. For the purpose of building load and resource tables and analyses that assume load based on 1-in-2 weather year conditions, DR capacity shall be counted from the 1-in-2 weather year condition ex-ante forecast of August load impact, portfolio-adjusted. For analyses that assume load based on 1-in-10 weather year conditions, DR capacity shall be counted from the 1-in-10 weather year condition ex-ante forecast of August load impact, portfolio-adjusted. For the purpose of building detailed profiles of DR load impact in system and local area planning models, DR is assumed available at times of system stress, subject to

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http://www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002-REV.pdf

[23] Straight-line interpolation for intervening years between the "Base" case and "High" case target years identified in the ICF report

[24] To access IOU Load Impact reports, please see:

PG&E: https://www.pge.com/regulation/DemandResponseOIR/Other-Docs/PGE/2013/DemandResponseOIR_Other-Doc_PGE_20130402_269621.pdf

SCE: http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/62A8F5E44C447F0688257B410052EC7B/$FILE/R.07-01-041_DR+OIR-SCE+DR+Portfolio+Summary+2012+-+Final.pdf

SDG&E: http://www.sdge.com/regulatory-filing/742/rulemaking-regarding-policies-and-protocols-demand-response-load-impact program operating constraints but not limited to operating hours specified in Resource Adequacy accounting rules. Program operating constraints are obtained from the Load Impact reports and tariffs for each program.[25]

TPP Base and local area studies may adjust the default DR assumption to account for uncertainty in both location and the ability of DR to mitigate specific contingencies of concern. CPUC staff expects discussions with the CAISO to lead to agreement on appropriate DR assumptions for local area studies. In the 2012 LTPP Track 4, CPUC and CAISO staff settled on the subset of DR that is "fast response", and located in the most effective areas for mitigating specific contingencies of concern, as an acceptable assumption for local area studies. "Fast response" in the Track 4 context refers to the expectation that such DR, when implemented, would be able to respond in sufficiently less time than 30 minutes from the CAISO dispatch, to allow CAISO operators enough time to detect a non-response and dispatch an alternative resource if needed to mitigate a contingency. CAISO suggests that an appropriate assumption going forward would be the greater of either of the CPUC 2012 LTPP Decisions in Track 1 or 4, or whatever the CAISO identifies and approves in the 2013-14 TPP.

4.2.6 RPS Portfolios

The forecast of renewable resources is developed using a tool called the 33% Renewable Portfolio Standard (RPS) Calculator. The 33% RPS Calculator uses public data to develop portfolios of renewable resources to use for planning studies. Since the cost of renewables is tied to the transmission cost to deliver the power to market, the Calculator selects a portfolio taking into consideration the amount of capacity currently available on the system, plus the amount of capacity an additional transmission line could make available and at what cost. So between two similar resources the Calculator would select the one with access to current transmission capacity over one that requires new transmission assets. The Calculator can solve for different policy priorities, such as quickest on-line time, lowest cost, least environmentally harmful, etc.

Generally, the Calculator first selects resources assumed as very likely to be constructed. Such resources are referred to as the "Discounted Core." Discounted Core projects meet two milestones: (1) an executed Power Purchase Agreement, and (2) a complete (i.e. data adequate) application for a major environmental permit. This is the same test as used for the renewable resource portfolios in the 2010 LTPP, but reflects a change from the 2012-13 TPP RPS portfolios.[26]

For planning purposes, existing RPS generation in California with contracts expiring before its expected

[25] To access IOU demand response tariffs, please see:

SCE: https://www.sce.com/wps/portal/home/business/savings-incentives/demand-response/

PG&E: http://www.pge.com/en/mybusiness/save/energymanagement/index.page

SDG&E: http://www.sdge.com/save-money/demand-response/overview

[26] For more information about the 33% RPS Calculator and past RPS portfolios, *see*: http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/LTPP2010/2010+LTPP+Tools+and+Spreadsheets.htm and http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/2012+LTPP+Tools+and+Spreadsheets.htm

retirement age are assumed in service until the retirement age.[27] This supply will not count towards any specific LSE, but will be included in the calculation of the expected renewable supply and will count toward filling the Renewable Net Short.

Two versions of the 33% RPS Calculator are published: one to model commercial interest in developing projects and another to model higher penetration amounts of distributed photovoltaic generation. Each portfolio uses the Discounted Core, as described above. All portfolios use the “Commercial Interest” score weighting which is 70% weight on the Commercial Interest score and 10% weight on each of the Environmental, Permitting, and Cost scores. An RPS portfolio developed for a specific scenario uses a Renewable Net Short calculation based on the assumptions specified in the scenario. While the 33% RPS Calculator is by default calibrated to 2024, the Scenario Tool maintains an approximation of the 33% RPS throughout the planning horizon. To develop this approximation, the 33% RPS Calculator is run with a Renewable Net Short for 2034. The difference in the amount of NQC from the RPS portfolio in 2024 and 2034 is converted to a linear growth rate. The NQC from renewables is assumed to change by this fixed amount each year after 2024 until the end of the planning horizon.

CPUC staff works with CEC staff in a collaborative process to build RPS portfolios. CEC staff provided environmental scores for new projects not previously scored. CEC staff also provided its understanding of projects online in 2013 and how the renewable net short should be calculated in light of incremental preferred resource assumptions. The CPUC builds the RPS portfolios with CEC input and then the agencies send to the CAISO the RPS portfolios to study in the TPP. The CAISO modeling, which is much more detailed than the RPS Calculator, then determines what if any transmission improvements are needed to make a portfolio deliverable.

The CPUC reminds users of the RPS Calculator that some of the cost and performance assumptions embedded in the calculator have become somewhat outdated, which limits its usefulness. For example, the RPS Calculator does not adjust the portfolios for the changes in a technology’s value related to its increased penetration and uses outdated fossil benchmarks that create a significant error in the value of portfolios. However, the cost and performance assumption are being updated in a new version of the RPS Calculator that should be completed in 2014. The RPS Calculator will be fundamentally redesigned so that resource options will be added to a portfolio based not on their individual value-vs.-cost, but based on how they impact the value-vs.-cost of the entire portfolio, since in reality the resources all interact when added to the system. The updated cost and performance assumptions and also the more sophisticated methodology would be especially important if considering potential RPS goals exceeding 33%.

The table below summarizes six different RPS portfolios intended to be modeled in different planning scenarios described later in this document.

Scenario / Sensitivity	**Demand Side Management**	**Version of 33% RPS Calculator**

[27] For the Renewable Net Short used in the 33% RPS Calculator, expiring contracts with out of state resources are assumed not to be renewed for purposes of meeting California’s RPS.

33% in 2024 Trajectory	EE tbd	Commercial Interest
33% in 2024 Trajectory (LCR version)	EE tbd	Commercial Interest
33% in 2024 High Load	EE tbd	Commercial Interest
33% in 2024 + DSM + High DG	EE tbd, Low PV, Low CHP	High DG
40% in 2030	EE tbd	High DG
40% in 2030 + High DSM + High DG	High EE, Low PV, High CHP	High DG

See the Appendix of this document for tables describing the makeup of the RPS portfolios by Competitive Renewable Energy Zones (CREZs) and by technology type.

4.2.7 Nuclear Retirements

Diablo Canyon Power Plant (DCPP) is assumed to have obtained renewal of licenses to continue operation beyond 2025. The alternative assumption is retirement in 2024-25. These assumptions should be informed by AB 1632 seismic and related studies around the DCPP area.

4.2.8 Once-Through-Cooled Technology Retirements

The default assumption is that power plants using OTC technology (except DCPP) retire according to the current State Water Resources Control Board (SWRCB) OTC compliance schedule.

4.2.9 Renewable and Hydro Retirements

A "Low" level of retirement assumes these resource types stay online unless there is an announced retirement date. A "Mid" level assumes solar and wind resources retire at age 25, other non-hydro renewable technologies retire at age 40, and hydro resources retire at age 70. A "High" level assumes solar and wind resources retire at age 20, other non-hydro renewable technologies retire at age 25, and hydro resources retire at age 50. Note that retirement assumptions based on facility age carry a wide range of uncertainty.

4.2.10 Other Retirements

A "Low" level of retirement assumes "Other" resource types stay online unless there is an announced retirement date. A "Mid" level assumes retirement based on resource age of 40 years or more. A "High" level assumes retirement based on resource age of 25 years or more. Note that retirement assumptions based on facility age carry a wide range of uncertainty.

4.2.11 Imports

The default value for imports shall be based on the CAISO Available Import Capability for loads in its control area. This is equal to the CAISO Maximum Imports minus Existing Transmission Contracts (ETCs) outside its control area.[28] For resources outside of the California ISO area, the latest publicly available Transmission Expansion Policy Planning Committee (TEPPC) data should be utilized, for example, either the 2022 or 2024 Common Case generation table.[29] An alternative assumption is the historical expected imports as calculated by the CEC.[30]

4.3 Other Assumptions

4.3.1 The Second Planning Period

The second planning period (2025-2034) will use simplified planning assumptions. Generally, these assumptions reflect extrapolation of the approaches of the first planning period.

- Net load growth will be maintained as an average, annual compound growth rate from the prior period. The growth rate will be calculated based on net load (i.e. the forecast load, after demand side adjustments such as AA-EE, incremental CHP, etc.), rather than extrapolating individual load or demand assumptions. The formula is:

$$GrowthRate = \left(\frac{NetLoad_{2024}}{NetLoad_{2014}}\right)^{\frac{1}{(2024-2014)}} - 1$$

  where Net Load is the gross load forecast minus: AA-EE, incremental small PV, and incremental demand side CHP. This annual growth rate is then applied to the 2024 Net Load to calculate the Net Load for 2025-2034.

- Resource retirements will be calculated based on resource age or other characteristic, as described for the first planning period of each scenario.
- Resource Additions (except renewables) will be calculated based on Known and Planned Additions for all scenarios.
- Imports will be assumed to remain constant from the 2024 value through the second planning period.
- Event-based DR will be assumed to remain constant from the 2024 value through the second planning period.
- RPS resource additions will be calculated using the 33% RPS Calculator based on an assumption

[28] http://www.caiso.com/Documents/2014Assigned-UnassignedRA_ImportCapability-BranchGroups-AfterStep6.pdf

[29] *See* Data/Surveys" at http://www.wecc.biz/committees/BOD/TEPPC/External/Forms/external.aspx

[30] As described in Appendix D, http://www.energy.ca.gov/2012publications/CEC-200-2012-003/CEC-200-2012-003.pdf

of a continued 33% RPS target as follows. In order to calculate the Renewables Net Short for the second planning period, the growth rate in net load for the scenario is applied to calculate a net load in 2034. For the purposes of the Scenario Tool, the incremental amount of RPS resources to reach the 2034 goal of 33% RPS is added in equal amounts each year from 2025 to 2034. Note that the planning area growth rate calculated in the Scenario Tool is applied to the statewide number in the Renewables Net Short calculation.

4.3.2 Deliverability

Resources can be modeled as Energy-only or Deliverable. The CAISO's TPP, for purposes of identifying needed policy-driven transmission additions, assumes that the renewable resource portfolios provided by the CPUC will require deliverability. Beyond that, however, in order to better allow for analysis of options for providing additional generic capacity, any additional resources will only be assumed Deliverable if they meet one of two criteria:

(1) Fits on the existing transmission and distribution system,[31] including minor upgrades,[32] or new transmission approved by both California ISO and CPUC, or

(2) Baseload or flexible resources.[33]

This assumption is only for study and planning purposes and does not prejudge any future CPUC decisions on transmission or resource approvals.

4.3.3 Price Methodologies

The same methodologies as were used in the 2012 LTPP shall be used for the 2014 LTPP.

Natural Gas

The CEC's Natural Gas Reference Case as put forward in the 2013 IEPR shall be used as the base for calculating natural gas prices.[34] This price series was constructed to be consistent in baseline assumptions with the CED forecast and therefore the two are congruent for planning purposes.

Greenhouse Gas

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[31] For this purpose, "fits" refers to the simple transmission assumptions listed on tab g – TxInputs of the 33% RPS Calculator. Staff shall collaborate with the California ISO to update the assumptions and to apply these assumptions to the resource portfolios.

[32] Minor upgrades do not require a new right of way; other factors such as cost are not considered.

[33] Flexibility currently does not have a standard definition, but a definition will be established either in this proceeding or in the Resource Adequacy proceedings (the current proceeding is R.11-10-023). Generally speaking, baseload resources are those that provide a constant power output, such as a nuclear plant while flexible resources are those that can respond to dispatch instructions. There is some overlap between these two categories, for example a baseload design combined cycle plant could provide some flexibility.

[34] The Energy Commission 2013 IEPR Revised Burner-tip Price Forecast can be obtained as described here: http://www.energy.ca.gov/2013_energypolicy/documents/2013-11-19_Notice_of_Availability.pdf

The Greenhouse Gas (GHG) price forecast as put forward in the 2013 IEPR Natural Gas Market Assessment: Outlook report, to be published in December 2013 by the CEC, shall be used as the base for calculating GHG prices.

Price differentiation may occur, for example, specified imports shall be subtracted from production cost modeling and accounted for, then remaining imports would be assigned annual GHG values based on an implied market heat rate or other value.

5 Planning Scenarios

The LTPP scenarios are developed to help answer current resource planning questions before the CPUC. The critical questions facing the 2014 LTPP include the following:

1. What new resources need to be authorized and procured to ensure adequate system reliability, both for local areas and the system generally, during the planning horizon?
    - What is the need for flexible resources and how does that need change with different portfolios? What operational characteristics (e.g. ramp rates, regulation speeds) are needed in what quantities? Are these needs location specific?
    - How does the potential retirement of major resources (e.g. once-through-cooling, nuclear) change the resource needs?
    - How can reliability needs be balanced against costs, while also creating opportunities for achieving economically efficient outcomes?
2. What mix of resources minimizes cost to customers over the planning horizon?
    - Is there a preferred mix of energy-only, fully deliverable resources, and demand side resources? How does this mix vary depending on the operational characteristics of the resources?
    - Does increased distribution-level generation reduce overall costs?
    - What synergies exist between generation and transmission resources, and between different types of supply resources that can be used to limit overall costs?

The TPP scenarios are developed for the CAISO transmission planning process, to assess the transmission system and propose transmission plans that identify cost-effective transmission additions or non-conventional alternatives over the planning horizon, based upon the following objectives:

1. Maintain reliability of the transmission system, both at the system level and in local planning areas;
2. Integrate the renewable generation in the CPUC RPS portfolios into the transmission system;
3. Perform an economic assessment of potential transmission projects.

5.1 2014 Planning Scenarios

The following scenarios were crafted through a collaborative effort amongst CPUC, CEC and CAISO staff to reflect a reasonable range of possible energy futures. In the development of these scenarios, the staff focused on examining the impact of key policies on the long-term planning of California's energy resources and infrastructure.

The Trajectory scenario reflects current state policies and programs and could be considered a "business as usual" future. The rest of the scenarios generally reflect sensitivities to the Trajectory scenario, by varying one particular policy or factor.[35] In this way, the scenarios are set up to inform policymakers about the implications of adopting a particular policy. The CAISO will model and assess these scenarios for CPUC consideration in the LTPP proceeding but they will not be incorporated into the TPP planning assumptions.

Inevitably, resource limitations will likely demand prioritization of the scenarios for their use in the LTPP. Input from LTPP parties will inform the decision as to which scenarios to prioritize above others in the LTPP.

The Scenario Matrix shown in the following section enumerates the detailed assumptions that form each scenario. The remainder of this section qualitatively describes the rationale for each scenario and provides additional details on the assumptions forming that scenario.

5.2 Trajectory Scenario

The Trajectory scenario is the control scenario for resource and infrastructure planning, designed to reflect a modestly conservative future world with little change from existing procurement policies and little change from business as usual practices. As described in the Load and Energy Efficiency subsections above, the specific load case and AA-EE scenario to be used from the 2013 IEPR CED forecasts has not yet been decided. The Trajectory scenario assumes no incremental demand-side small PV or CHP beyond what is already embedded in the 2013 IEPR CED. For supply-side resources, this scenario counts all existing resources, assumes the default for conventional additions, no net growth in supply-side CHP, the default for storage and DR, a commercial-interest driven RPS portfolio maintaining the 33% standard in 2024, no nuclear retirement, a low level of renewable and hydro retirement, a mid level of retirement for other resource types, and the default for imports.

5.2.1 TPP Application of the Trajectory Scenario

As noted above, the CAISO will use the Trajectory Scenario in the transmission planning process to assess the transmission system and propose transmission plans that identify cost-effective transmission additions or non-conventional alternatives over the planning horizon. The categories of transmission additions considered by the CAISO in this process are based upon the following objectives:

[35] Note that one policy change could require varying multiple input assumptions.

1. Reliability - Maintain reliability of the transmission system (local planning areas and the bulk system);
2. Policy-driven - Integrate the renewable generation in the CPUC RPS portfolios into the transmission system;
3. Economic - Perform an economic assessment of potential transmission projects.

As illustrated in the Scenario Matrix in the following section, the various components of the TPP use different weather variants of the mid demand case from the 2013 IEPR CED forecast. Also as described above in the Planning Assumptions section of this document, the local reliability studies portion of the TPP may conservatively adjust the AA-EE, storage, and DR assumptions away from the Trajectory scenario defaults to account for uncertainty.

Both the Policy-driven and Economic Studies portions of the TPP will evaluate impacts from two cases, a commercial-interest driven RPS portfolio and a High DG driven RPS portfolio.

5.3 High Load Scenario

The High Load scenario explores the impact of higher demand on the system, with all other inputs held constant. CPUC Energy Division proposes to evaluate increased demand via higher economic and demographic growth, to see the impact of more energy demand on the system (versus studying only a higher system peak). This scenario diverges from the Trajectory scenario by using the high demand case from the 2013 IEPR CED forecast. This scenario also uses a commercial-interest driven RPS portfolio built assuming high load and maintaining the 33% standard in 2024.

5.4 Diablo Canyon Impact Scenario

This scenario explores the potential loss of about 2,240 MW of baseload capacity from PG&E's Diablo Canyon Power Plant (DCPP), assuming it retires when its license expires in 2024 (Unit 1) and 2025 (Unit 2). The only difference between this scenario and the Trajectory scenario is the retirement of DCPP in 2024 and 2025.

5.5 High DG Scenario

This scenario explores the implications of promoting high amounts of distributed generation (DG), which may imply more aggressive pursuit of customer-sited distributed generation programs, and a shift in RPS procurement towards favoring wholesale distributed generation projects. This scenario diverges from the Trajectory scenario by assuming moderate incremental amounts of demand-side small PV and CHP beyond what is embedded in the 2013 IEPR CED forecast, and uses a High DG driven RPS portfolio maintaining the 33% standard in 2024.

5.6 40% RPS Scenario

The 40% RPS scenario would assess the operational impacts associated with a higher RPS target post-2020. Given that the CA legislature is exploring the establishment of a higher RPS target, this scenario would provide policymakers with data to evaluate the system impact of this increased penetration of renewables to the grid. This scenario diverges from the Trajectory scenario by using a High DG driven RPS portfolio that targets achieving a 40% standard in 2030.

5.7 Expanded Preferred Resources Scenario

The Expanded Preferred Resources scenario would assess the impact of pursuing higher levels of preferred resources in order to take an ambitious step toward the California Air Resources Board's (CARB) 2050 greenhouse gas (GHG) emission reduction goals. CARB, via AB 32, seeks to reduce GHG emissions by 80% beyond 1990 levels by the year 2050. This scenario diverges from the Trajectory scenario by assuming the highest amounts of AA-EE , moderate incremental amounts of demand-side small PV beyond what is embedded in the 2013 IEPR CED forecast, high penetration of new demand and supply-side CHP, and a High DG driven RPS portfolio that targets achieving a 40% standard in 2030.

6 Scenario Matrix

The table below defines each of the assumptions for each of the scenarios.

2014 LTPP Scenarios (2024, 2034 Target Years)				Demand				Supply										
#	Name	Notes	Priority	Load	AA-EE	PV	CHP	Existing	Conventional Additions	CHP Additions	Storage Additions	DR	RPS Portfolio	Nuclear Retirement	OTC Retirements	Renewable + Hydro Retirements	Other Retirements	Imports
1	Trajectory scenario	Proposed base assumptions for TPP and LTPP studies. The TPP may make adjustments for weather and location uncertainty as indicated below.		Mid(1in2)	TBD	IEPR	IEPR	NQC List	Default	None	Default	1-in-2 weather load impacts	33% Comm'l Port	None	Default	Low	Mid	Default
a	Base-TPP Local Area Reliability Studies	Local area reliability studies using mid 1-in-10 weather normalized demand forecast. Due to locational uncertainty of AA-EE, DR, and Storage, a more conservative assumption is used.		Mid(1in10)	TBD	IEPR	IEPR	NQC List	Default	None	Default adj for LCR	1-in10 weather load impacts adj for LCR	33% Comm'l Port (LCR version)	None	Default	Low	Mid	Default
b	Base-TPP Bulk System Reliability Studies	For bulk system reliability studies using the mid 1 in 5 weather normalized demand forecast.		Mid(1in5)	TBD	IEPR	IEPR	NQC List	Default	None	Default	1-in-2 weather load impacts	33% Comm'l Port	None	Default	Low	Mid	Default
c	Base-TPP Policy Studies	Policy studies using mid 1-in-5 weather normalized demand forecast. The 33% Comm'l Int RPS Port will be assessed. Prod cost sims (zonal) and Power flow studies (busbar level).		Mid(1in5)	TBD	IEPR & IEPR+Low Inc PV	IEPR & IEPR+Low Inc CHP	NQC List	Default	None	Default	1-in-2 weather load impacts	33% Comm'l Port & 33% High DG Port	None	Default	Low	Mid	Default
d	Base-TPP Economic Studies	Economic studies using mid 1-in-2 weather normalized demand forecast. The 33% Comm'l Int RPS Port will be assessed. Prod cost sims (nodal) only.		Mid(1in2)	TBD	IEPR & IEPR+Low Inc PV	IEPR & IEPR+Low Inc CHP	NQC List	Default	None	Default	1-in-2 weather load impacts	33% Comm'l Port & 33% High DG Port	None	Default	Low	Mid	Default
2	High Load	High econ/demo case for 1-in-2 weather year (higher peak and annual energy). Potential scenario for the LTPP Operational Flexibility Studies.		High(1in2)	TBD	IEPR	IEPR	NQC List	Default	None	Default	1-in-2 weather load impacts	33% Comm'l Port High Load	None	Default	Low	Mid	Default
3	Diablo Canyon Impact	Diablo Canyon retires in 2024/25. Potential scenario for the LTPP Operational Flexibility Studies.		Mid(1in2)	TBD	IEPR	IEPR	NQC List	Default	None	Default	1-in-2 weather load impacts	33% Comm'l Port	DCPP 2024/25	Default	Low	Mid	Default
4	High DG	DG may be projects < 20 MW in size but should also exclude projects located outside load pockets (e.g. in middle of desert). Potential scenario for the LTPP Operational Flexibility Studies.		Mid(1in2)	TBD	IEPR+Low Inc PV	IEPR+Low Inc CHP	NQC List	Default	None	Default	1-in-2 weather load impacts	33% w DSM + High DG Port	None	Default	Low	Mid	Default
5	40% RPS in 2030	Potential scenario for the LTPP Operational Flexibility Studies.		Mid(1in2)	TBD	IEPR	IEPR	NQC List	Default	None	Default	1-in-2 weather load impacts	40% 2030 High DG Port	None	Default	Low	Mid	Default
6	Expanded Preferred Resources	Combination of policies to work toward AB 32 2050 GHG goals. Potential scenario for the LTPP Operational Flexibility Studies.		Mid(1in2)	High	IEPR+Low Inc PV	IEPR+High Inc CHP	NQC List	Default	High Inc CHP	Default	1-in-2 weather load impacts	40% w High DSM + High DG Port	None	Default	Low	Mid	Default

Yellow highlights indicate assumptions that differ from the Trajectory scenario.

7 Appendix

7.1 RPS Porfolios Summary

Note: As of December 11, 2013, CPUC staff has produced illustrative RPS portfolios as shown below based on selected load cases and AA-EE scenarios from the 2013 IEPR CED forecasts. Final RPS portfolios are not yet determined pending a final decision on load and AA-EE that will be documented in the 2013 IEPR final report, scheduled to be adopted at the CEC's January 15, 2014 Business Meeting.

The table below summarizes the renewable net short calculation for each RPS Portfolio.

Renewable Net Short Calculation (GWh)						
	All Values in GWh for the Year 2022	**Formula**	**Base 33% (Mid-Mid EE) 2024**	**Base 33% (Mid-Low EE) 2024**	**33% Comm'l High Load 2024**	**High DG + ("Mid-Mid EE") 2030 (40%)**
1	Statewide Retail Sales - October 2013 IEPR (prelliminary)		300,516	300,516	317,781	306,345
2	Non RPS Deliveries (CDWR, WAPA, MWD)		9,272	9,272	9,272	*
3	Retail Sales for RPS	1-2=3	291,244	291,244	308,509	*
4	Additional Energy Efficiency		26,646	18,355	26,646	*
5	Additional Rooftop PV		-	-	-	*
6	Additional Combined Heat and Power		-	-	-	*
7	Adjusted Statewide Retail Sales for RPS	3-4-5-6=7	264,598	272,889	281,863	269,730
8	**Total Renewable Energy Needed For RPS**	7*33% (or 7*40%)=8	**87,317**	**90,053**	**93,015**	**107,892**
	Existing and Expected Renewable Generation					
9	Total In-State Renewable Generation		**42,909**	**42,909**	**42,909**	**42,909**
10	Total Out-of-State Renewable Generation		**10,639**	**10,639**	**10,639**	**10,639**
11	Procured DG (not handled in Calculator)		**2,204**	**2,204**	**2,204**	**2,204**
12	SB 1122 (250 MW of Biogas)		**1,753**	**1,753**	**1,753**	**1,753**
13	**Total Existing Renewable Generation for CA RPS**	9+10+11+12=13	**57,504**	**57,504**	**57,504**	**57,504**
14	**Total RE Net Short to meet 33% RPS In 2022 (GWh)**	8-13=14	**29,813**	**32,549**	**35,511**	**50,388**
	Annual Growth Rate of Managed Load (2014-2024)					*0.0032*

* left blank because the RNS calculation for this scenario is derived by extrapolating the 2024 "Adjusted Statewide Retail Sales for RPS" that is embedded in the Scenario Tool; the extrapolation factor used for this calculation is the "annual growth rate of managed load (2014-2024)"

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The table below summarizes the RPS Portfolios by CREZ.

CREZ Breakout (MW)				
Total Out-of-State Renewable Generation	10,639	10,639	10,639	10,639
Net Short (GWh)	29,813	32,549	35,511	50,388
Scenario Name	Base 33% (Mid-Mid EE) 2024	Base 33% (Mid-Low EE) 2024	33% Comm'l High Load 2024	High DG + ("Mid-Mid EE") 2030 (40%)
	Portfolio Totals (MW)	Portfolio Totals (MW)	Portfolio Totals (MW)	Portfolio Totals (MW)
Discounted Core	9,103	9,173	9,208	14,614
Commercial Non-Core	0	0	0	0
Generic	2,430	3,538	4,654	6,469
Total	11,534	12,712	13,862	21,083
CREZ	MW	MW	MW	MW
Alberta	300	300	300	300
Arizona	400	400	400	400
Baja	100	100	100	100
Barstow	-	-	-	-
British Columbia	-	-	-	-
Carrizo North	-	-	-	-
Carrizo South	900	900	900	900
Colorado	-	-	-	-
Cuyama	-	-	-	-
Distributed Solar - PG&E	984	984	984	3,630
Distributed Solar - SCE	565	565	565	3,105
Distributed Solar - SDGE	143	143	143	362
Distributed Solar - Other	-	-	-	-
Fairmont	-	-	-	-
Imperial	1,840	1,840	1,840	1,840
Inyokern	-	-	-	-
Iron Mountain	-	-	-	-
Kramer	642	642	642	642
Lassen North	-	-	-	-
Lassen South	-	-	-	-
Montana	-	-	-	-
Mountain Pass	658	658	658	658
Nevada C	516	516	516	516
Nevada N	-	-	-	-
New Mexico	-	-	-	-
NonCREZ	185	185	191	457
Northwest	-	-	-	-
Owens Valley	-	-	-	-
Palm Springs	-	-	-	-
Pisgah	-	-	-	-
Remote DG (Brownfield) - PG&E	-	-	-	-
Remote DG (Brownfield) - SCE	-	-	-	-
Remote DG (Brownfield) - SDGE	-	-	-	-
Remote DG (Brownfield) - Other	-	-	-	-
Remote DG (Greenfield) - PG&E	-	-	-	-
Remote DG (Greenfield) - SCE	-	-	-	-
Remote DG (Greenfield) - SDGE	-	-	-	-
Remote DG (Greenfield) - Other	-	-	-	-
Riverside East	2,083	3,261	3,800	3,800
Round Mountain	-	-	-	-

San Bernardino - Baker	-	-	-	-
San Bernardino - Lucerne	87	87	87	147
San Diego North Central	-	-	-	-
San Diego South	-	-	374	384
Santa Barbara	-	-	-	-
Solano	-	-	200	200
Tehachapi	1,653	1,653	1,653	2,763
Twentynine Palms	-	-	-	-
Utah-Southern Idaho	-	-	-	-
Victorville	-	-	-	-
Westlands	475	475	505	775
Wyoming	-	-	-	-
Central Valley North	-	-	-	100
El Dorado	-	-	-	-
Merced	5	5	5	5
Los Banos	-	-	-	-
Total	11,534	12,712	13,862	21,083

The table below summarizes the RPS Portfolios by technology type.

Technology Breakout (MW)				
Total Out-of-State Renewable Generation	10,639	10,639	10,639	10,639
Scenario / Ranking Score Weighting	Commercial Interest	Commercial Interest	Commercial Interest	Commercial Interest
Scenario Name	Base 33% (Mid-Mid EE) 2024	Base 33% (Mid-Low EE) 2024	33% Comm'l High Load 2024	High DG + ("Mid-Mid EE") 2030 (40%)
Statewide Retail Sales - Dec 2013 IEPR	300,516	300,516	317,781	306,345
Net Short (GWh)	29,813	32,549	35,511	50,388
	Portfolio Totals (MW)	Portfolio Totals (MW)	Portfolio Totals (MW)	Portfolio Totals (MW)
Discounted Core	9,103	9,173	9,208	14,614
Commercial Non-Core	0	0	0	0
Generic	2,430	3,538	4,654	6,469
Total	11,534	12,712	13,862	21,083
Biogas	20	20	23	23
Biomass	103	103	103	103
Geothermal	493	493	493	493
Hydro				
Large Scale Solar PV	6,281	7,379	7,887	9,402
Small Solar PV	2,066	2,076	2,114	7,636
Solar Thermal	1,248	1,318	1,350	1,350
Wind	1,323	1,323	1,892	2,077
Total	11,534	12,712	13,862	21,083
New Transmission Segments	Kramer - 1	Kramer - 1	Kramer - 1	Kramer - 1
	Riverside East - 1	Riverside East - 1	Riverside East - 1	Riverside East - 1