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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 12-03-014 (Filed March 22, 2012)

REVISED ASSIGNED COMMISSIONER'S RULING SETTING FORTH STANDARDIZED PLANNING SCENARIOS FOR COMMENT

This ruling modifies my September 20th ruling on this topic. Please note the revised filing dates and correction of Table 9 in the attachment.

The May 17, 2012 Scoping Memo for this proceeding established three tracks for this proceeding. Track 2 is the system needs track. As part of this track, I issued a Ruling establishing standardized planning assumptions on June 27, 2012. Additional comments on incremental energy efficiency forecasts were filed after that Ruling. From those planning assumptions and comments, Energy Division held a workshop and drafted planning scenarios, upon which parties have been able to informally provide technical comments. I now issue the planning scenarios in the Attachment to this Ruling for formal comment.

IT IS RULED that parties may comment on the planning assumptions in the Attachment to this Ruling no later than October 5, 2012. Parties may reply to such comments no later than October 19, 2012.

Dated September 25, 2012, at San Francisco, California.

/s/ MICHEL PETER FLORIO
Michel Peter Florio
Assigned Commissioner

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ATTACHMENT

Revised Scenarios

for use in Rulemaking12-03-014

September 2012

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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 Utilities
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 event (peak) forecast
1-in-5	1-in-5 year weather event (peak) forecast
1-in-2	1 in 2 year weather event (peak) forecast
AB	Assembly Bill
CED	California Energy Demand Forecast
DSM	Demand Side Management
CHP	Combined Heat and Power
GWh	Gigawatt Hour
IEPR	Integrated Energy Policy Report
LCA	Local Capacity Area
LCR	Local Capacity Requirement
LTPP	Long Term Procurement Plan
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

Definitions

An **Assumption** is a statement about the future for a given resource or resource type. For example, future load conditions are an assumption.

A **Scenario** is 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.

A **Portfolio** is 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.

Sensitivities are variations 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.

The Load Forecast refers to load levels, measured by both annual peak demand and annual energy consumption. Load forecasts are strongly influenced by economic and demographic factors.

A **Managed Forecast** refers to a forecast that has been adjusted to account for programs or expectations not embedded into the 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.

The 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 refers to the need to build new resources or maintain existing resources from an electrical reliability perspective.

Bundled Plans refers to the three large Investor Owned Utilities' procurement plans established in compliance with AB 57 to determine upfront and reasonable procurement standards.

I. Background

The Long Term Procurement Plan (LTPP) proceedings were established to ensure a safe, reliable and cost-effective electricity supply in California.[1] Track II[2] of the 2012 LTPP addresses the overall long-term need for new system reliability resources, including the adoption of system resource plans. These resource plans will allow the Commission to comprehensively consider the impacts of state energy policies on the need for new resources. Based on these system resource plans, the Commission shall consider updates to the Investor-Owned Utilities' (IOUs) bundled procurement plans with a focus on the IOU's obligation to maintain electric supply procurement responsibilities on behalf of IOU customers.

II. Introduction

This LTPP proceeding was initiated 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]

On May 10, 2012, the Energy Division[5] served its 2012 *Energy Division Straw Proposal on LTPP Planning Standards* (Straw Proposal) to the service list in this proceeding. A workshop was held on May 17, 2012 to discuss the Straw Proposal. That same day, the Scoping Memo was issued, defining the parameters of the 2012 LTPP proceeding.[6] Parties were given the opportunity to file comments on the Straw Proposal on May 31, 2012 and reply comments on June 11, 2012.[7]

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[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, (R.)12-03-014, issued May 17, 2012.

[3] This proceeding follows Rulemaking (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] Throughout this document, "Energy Division", "Energy Division Staff", "ED", "ED Staff", and "Staff" all refer to the staff of the California Public Utilities Commission (CPUC) Energy Division.

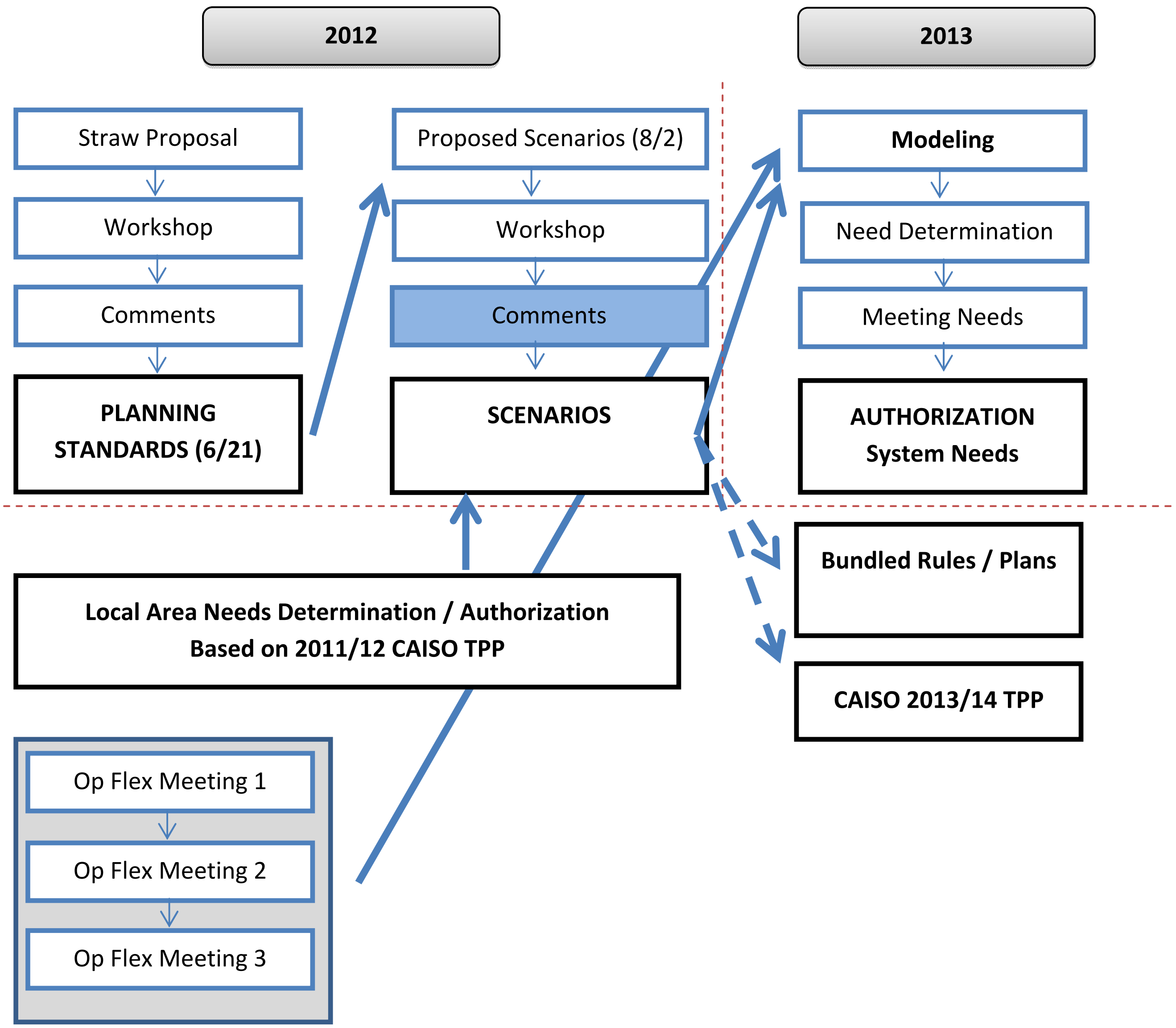
[6] *See* Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge, (R.)12-03-014, issued May 17, 2012.

[7] *Id.*

On June 27, 2012, the Assigned Commissioner's Ruling introduced to parties the planning assumptions to be used in the 2012 LTPP proceeding.[8] Those assumptions formed the building blocks for the LTPP scenarios set forth in the Energy Division Proposed Scenarios, served to parties on August 2, 2012. Energy Division conducted a workshop on August 24, 2012, and received technical comments from parties through September 11, 2012. This revised proposal is the next step in the scenario development process; comments are expected in October 2012, ultimately leading to a CPUC decision adopting scenarios and assumptions. The Building Scenarios section below discusses the core concepts of the scenario process.

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

III. 2012 LTPP Roadmap



IV. Guiding Principles

The Guiding Principles for the 2012 LTPP were established in the July 27th Assigned Commissioner's Ruling:

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.[9]

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. **Agencies** including CPUC, Energy Commission, and the California ISO should strive to reach common understandings and interpretations of planning assumptions.[10]

V. Planning Scope: Area, Time Frame & Assumptions

The following proposed scenarios are specifically created for the California ISO controlled transmission grid and the associated distribution systems. The planning period is established as twenty years in order to take into consideration the major impacts of infrastructure decisions now under consideration. While detailed planning assumptions are used to create an annual assessment in the first ten years (2013-2022), more generic long-term planning assumptions are utilized in the second period (2023-2034), reflecting the heightened uncertainties around future conditions. The second period is designed to

[9] Scenarios used by the California ISO Transmission Planning Process must meet the requirements in Section 24.4.6.6 of the California ISO's Tariff. Scenarios developed in the LTPP process may inform the development of the California ISO's TPP scenarios to the extent feasible under their tariff and adopted by their organization.
[10] ACR (R.) 12-03-014, p. 8.

inform resource choices made today as well as shape policy discussions, and not to make authorizations of need in those years.[11]

The set of planning assumptions in the LTPP are listed below. A thorough discussion of each assumption is discussed in its own section of June 27th Assigned Commissioner's Ruling.

List of Demand and Supply Planning Assumptions

Demand

Peak Weather Impacts
Economic and Demographic Drivers
Load Forecast (IOU Planning Area)
Incremental Uncommitted Energy Efficiency (3 large IOU programs)
Non-Event Based Demand Response (3 large IOU programs)
Incremental Small Photovoltaic (behind the meter) (IOU Planning Area)
Incremental CHP (behind the meter) (Reduced to 81% from Statewide goal)

Supply

All Resources
Existing Resources
Imports
Resource and Transmission Additions (IOU Planning Area)
Deliverability
Event-Based Demand Response (3 large IOU programs)
Incremental CHP (supply side) (Reduced to 81% from Statewide goal)
Resource Retirements

[11] *See* ACR (R.)12-03-014, p. 9.

VI. Building Scenarios

The LTPP scenarios are developed to help answer current resource planning questions before the Commission. The critical questions facing the 2012 LTPP include the following:[12]

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 electrical 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?

VII. 2012 Scenarios

Resource limitations demand prioritization of scenario modeling in favor of scenarios that can provide actionable guidance to decision makers regarding realistic future outcomes. In the Energy Division Proposed Scenarios, served on August 2, 2012, ED Staff presented three unique scenarios with six distinct sensitivity analyses to evaluate potential futures. Based on refinements from comments received to date as well as comments at the workshop, some scenarios and sensitivities have been changed, and others eliminated.

[12] Questions are referenced from ACR (R.)12-03-014, pp. 6-7.

In the LTPP, scenarios and sensitivities have greater or lower priority based on the modeling purposes. For example, a sensitivity of different renewable generation resource locations may have a more significant impact in transmission planning (e.g. power-flow) studies than in operational flexibility studies. These different cases and priorities are also established based on the guiding principles for the LTPP.

For the operational flexibility studies, Staff proposes four scenarios as high priority and a second tier of two scenarios to be modeled if time and resources allow. The four high priority scenarios are: Base Scenario, Replicating the TPP Scenario, Early SONGS Retirement Scenario, and High Distributed Generation, High Demand Side Management Scenarios. The Base Scenario provides an "expected" case. The Replicating TPP Scenario reflects a high unmanaged load future combined with 1-in-5 peak weather conditions.[13] Accordingly, this scenario may stress operating flexibility by committing available resources for energy and thereby limiting their use for flexibility. Early SONGS Retirement explores a future without the significant energy contributions of a major baseload resource (SONGS) in the first planning period (2015) and the retirement of another (Diablo Canyon) in the second planning period (2024). Similar to the TPP scenario, this case may commit flexible resources for energy, yet it also provides expected peak load reductions from demand side resources. The High Distributed Generation, High Demand Side Management Scenario, in contrast, explores a future with lower energy demand and higher production from variable distributed generation; this scenario may stress available flexibility in a different way, by presenting the highest percentage of variable resources relative to load.

The second tier priority for modeling includes (4) the Stress Peak Case scenario and (5) the High Distributed Generation, High Demand Side Management, 40% RPS in 2030. The Stress Peak Case models the Base Scenario with a higher 1-in-5 peak weather condition. This scenario would provide a sense of the world between the Base Scenario, the CPUC's expected future, and the Replicating TPP Scenario, which aims to model the CAISO's stressed future for transmission planning. The High Distributed Generation, High Demand Side Management, 40% RPS by 2030 Sensitivity, envisions the implications of a 40% RPS target upon the system, ratcheting up the stress on availability flexibility from the High

[13] Energy Division Staff and several parties indicated in workshops that it is important to reiterate the importance of aligning scenario planning where possible between the Commission and the California ISO. The Replicating TPP Scenario is set up to align with the California ISO's current processes and methods for transmission planning, providing a point of comparison between the two processes. The California ISO may also find it useful to incorporate some of what is included in the Commission scenarios to the TPP where doing so will be both useful and consistent with California ISO tariff obligations.

Distributed Generation, High Demand Side Management Scenario. A table of the proposed scenarios with the corresponding assumptions can be found in Section XIII. 2012 LTPP Scenario Matrix.

Two sensitivities from the Proposed Scenarios, Early Nuclear Retirement[14] and Environmental [15] are not recommended for modeling within the LTPP cycle at this time. However, Staff has provided the set of assumptions appropriate for examining these two alternatives in the Scenario Matrix in Section XIII in case there is use for them in other applications, such as transmission planning. The selected scenarios and sensitivities effectively capture a wide range in future variability that will provide a strong framework for the 2012 LTPP. In this way, these scenarios best reflect the LTPP proceeding's ultimate goal of creating plans that ensure a safe, reliable and cost-effective electricity supply in California while also meeting the guiding principles.

VII.a. Renewable Resource Assumptions in All Scenarios

The June 27th Assigned Commissioner's Ruling on Standardized Planning Assumptions stated an intent to use an estimate of expected renewable supply from the RPS proceeding (R.11-05-005). That ruling also stated that if no viable and appropriate renewable supply estimate emerged from the RPS proceeding in time for inclusion in the planning scenarios, that the 33% RPS Calculator would be used to develop portfolios instead.[16]

Staff and parties have discussed in many forums (e.g. LTPP and RPS workshops and comments) the challenges surrounding the assumption of what renewables supply estimate to use for planning. A basic tension clearly emerges among several goals: transparency, the need for detailed planning information (i.e. transmission planning requires specific resources at specific locations), confidentiality, and the use of the most accurate and current information. Thus far, parties have not proposed any workable solution that meets all of these goals nor have they agreed to relax any confidentiality provisions.

Given this impasse, the only option is to use simple, public milestones as a yes/no test to include resources in planning studies and return to using the 33% RPS Calculator. The milestones for the

[14] The Early Nuclear Retirement sensitivity would have had both SONGS and Diablo Canyon nuclear facilities as offline starting 2015.

[15] The Environmental sensitivity changed the projected RPS build out from the current procurement path. However, as illustrated in the 2010 LTPP, there are only minor differences from a system flexibility perspective (as opposed to a transmission planning perspective) between the Commercial and Environmental RPS portfolios.

[16] Attachment to the June 27th ACR, page 20.

discounted core in Staff's proposed scenarios are: 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.[17]

VIII. Base Scenario

The Base Scenario is the "control" for our analysis, designed to reflect the expected future world with little change from existing procurement policies. The Base serves as the point of reference for the rest of the scenarios.

To project load in the Base Scenario, the Mid load forecast, with a 1-in-2 weather peak is assumed. The demand side assumptions utilize the California Energy Demand Forecasts (CED) to provide the base and incremental values of demand forecasts.[18] For adjustments to the CED, the Energy Commission's estimates of certain incremental resources are included. The uncommitted EE adjustment is derived from the July 2012 CEC Incremental Uncommitted Forecast's incremental EE Mid "savings scenario" value without naturally occurring savings.[19] As for Incremental Demand Response (DR), the Base Case assumes the Mid assumption. The Mid assumption is derived from the values in the IOU's most recent Load Impact Reports filed with the Commission.[20]

In the case of demand side Small PV, the impacts of programs like the CA Solar Initiative are already embedded in the CEC forecast. Accordingly the incremental Small PV identified in this assumption is beyond programs already existing. Staff proposes the Mid assumption for Incremental Small PV[21], which is 1,300 MW beyond what is already embedded in the Mid load forecast, reflecting a modest level of

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[17] 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

[18] Base values are those that can be considered wholly in and of themselves without being tied to another forecast, while incremental values are those not embedded in the underlying demand forecast. *See* ACR (R.)12-03-014, p. 10.

[19] ACR (R.)12-03-014, p. 12. On August 1, 2012, Staff sent the incremental EE analysis to the R.12-03-014 service list, triggering the seven day comment period.

[20] The most current Load Impact Reports are from June 1, 2012. Note that this also includes PG&E's pending peak time rebate program.

[21] Small PV is defined as up to 5 MW in AC nameplate capacity. ACR (R.)12-03-014, p. 13.

increases in small PV resources based on the change in Net Energy Metering (NEM) from D.12-05-036.[22] Like Small PV, some demand side combined heat and power (CHP) resources[23] are embedded in the CED forecast. The revised ICF International analysis of Incremental CHP resources serves as the basis for the CHP scenarios.[24] The Base Case assumes no change in net CHP capacity (0 MW nameplate, 75% capacity factor) for both demand side and supply side Incremental CHP. For demand side Non-Event Based Demand Response, no additional value is assumed in the Base Case beyond that embedded in the 2011 CED.[25]

Resource Additions are treated in the analysis as existing generation. Both Known Additions and Planned Additions shall be used in all scenarios, while assumptions for renewable resources are addressed in their own category.[26]

Given the broad differences in the expected lifetimes among resource types, Energy Division Staff has selected different "expected" retirement frameworks based on resource type, reflected by the Mid assumption for once-through-cooling and "Other" resources, and the Low value for Nuclear, Hydroelectric, and select Renewable resources. Thus, hydroelectric plants and certain categories of renewables are assumed repowered with electrically equivalent resources at the end of resource life.[27] For once-through-cooling (OTC) units or units linked to the operation of OTC units, this means that units will be classified as retired by either the State Water Resources Control Board (SWRCB) deadline or the announced retirement date, whichever comes first.[28] Also, nuclear units are assumed to be relicensed for continuous operation, with both San Onofre Nuclear Generating Station and Diablo Canyon online and in operation through the planning horizon.[29]

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[22] For more information on Decision Regarding the Calculation of the Net Energy Metering Cap, (D.)12-05-036, *see* http://docs.cpuc.ca.gov/published/Final_decision/167591.htm.

[23] Demand side Incremental CHP are CHP resources that serve on-site load and not exporting electricity to the grid, while supply side are those that export electricity to the grid. ACR (R.)12-03-014, p. 13, 17.

[24] To reference ICF International's February 2012 analysis, *see* ICF International, Policy Analysis and 2011-2030 Market Assessment, *available at* http://www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002-REV.pdf. *See also* ACR (R.)12-03-014, p. 13.

[25] ACR (R.)12-03-014, p. 13.

[26] Known additions are resources that have a contract in place, have been permitted, and have construction under way. Planned Additions are resources that have a contract, but have not yet begun construction. ACR (R.)12-03-014, p. 15.

[27] Note that the date of rewinding will reset the retirement timing. *Id.*

[28] Note that Track II is treated as retirement. ACR (R.)12-03-014, p. 23.

[29] ACR (R.)12-03-014, p. 24.

Imports shall be based on the CAISO Available Import Capability for loads in their control area. This is equal to the CAISO Maximum Imports minus Existing Transmission Contracts (ETCs) outside their control area.[30]

For the 33% RPS portfolio, the Commercial Interest portfolio is selected. This portfolio is designed to be the best forecast of future RPS development using commercial interest as a key selection factor.[31]

How to Get There: The *Base Scenario* requires no change to the business as usual trajectory. All current policies are assumed as maintained or extended with little change in current practices. The *Base* presumes that these policies achieve results consistent with current achievement and forecast expectations.

VIII.a. Early SONGS Retirement Sensitivity

One of the essential questions facing this LTPP is the long-term status of our nuclear generating facilities. Specifically, how can system reliability be maintained with the retirement and/or non-relicensing of some or all of these units? The acutely heightened uncertainty surrounding the San Onofre Nuclear Generating Station (SONGS) requires particular focus on understanding the long term planning implications of the state's nuclear fleet.

This sensitivity was developed to explore the implications of a key nuclear relicensing and retirement possibility facing the Commission. For the large IOU-owned nuclear plants, three alternatives were proposed in the ACR's Planning Assumptions. Under the Low retirement scenario, selected for the Base Scenario, both SONGS and Diablo Canyon are assumed online and in operation throughout the planning horizon. In the Mid retirement scenario, the plants would remain in operation until their current licenses expire and then would retire. Under a High retirement scenario, both plants would be retired effective January 1, 2015.

The Early SONGS Retirement sensitivity departs from these alternatives by applying a Modified High assumption, with SONGS retired on January 1, 2015 and Diablo Canyon online until relicensing in 2024

[30] http://www.caiso.com/Documents/2013Assigned_UnassignedRAImportCapability_BranchGroups-AfterStep6.pdf. For resources outside of the California ISO, the Transmission Expansion Policy Planning Committee (TEPPC) data should be utilized, specifically the 2022 Common Case generation table. *See* Data/Surveys" at http://www.wecc.biz/committees/BOD/TEPPC/External/Forms/external.aspx.
[31] ACR (R.)12-03-014, p. 20.

(Unit 1) and 2025 (Unit 2). Note that in no way does this sensitivity intend to pre-judge Commission action on nuclear retirements; instead it seeks to inform Commission decision making in this area.

How to Get There: The *Early SONGS Retirement Sensitivity* requires a policy change to realize the near-term retirement of SONGS in 2015, and Diablo Canyon upon the expiration of its license in 2024/2025.

VIII.b. Stress Peak Case Sensitivity

This sensitivity is closely linked to both the Base Scenario and the Replicating Transmission Planning Process (TPP) Scenario (which immediately follows). The Stress Peak Case is identical to the Base Scenario, with one exception: it assumes a 1-in-5 peak weather year, as opposed to the Base Scenario's 1-in-2 peak weather year. Unlike the Replicating TPP Scenario, the Stress Peak sensitivity includes the impacts of various demand side programs as well as a business as usual expectation of demand response programs. By creating a hybrid of these two scenarios, this sensitivity aims to capture a future with relatively higher peak loads and thus, increased system stress.

How to Get There: Just as with the *Base Scenario*, the *Stress Peak Case Sensitivity* requires no change to the business as usual trajectory. All current policies are assumed be maintained or extended with little change in current practices. Policies are expected to achieve results consistent with current achievement and forecast expectations.

IX. Replicating Transmission Planning Process (TPP) Scenario

This Scenario, Replicating the California ISO's TPP, was created to form a point of convergence between the LTPP and the TPP by trying to match the assumptions that have been generally utilized by the California ISO in its TPP. By aligning the assumptions of the two planning processes in this way, Staff seeks to facilitate the exchange of information between the CPUC and California ISO with the ultimate goal of more effectively coordinating generation and transmission resource planning.[32]

[32] As set forth in the June 27th Assigned Commissioner's Ruling, the CPUC Staff has worked with the California ISO in recent years to develop consistency across the LTPP and TPP processes. CPUC Staff seeks alignment on key planning assumptions and scenarios where possible, while recognizing that the California ISO is bound by its tariff in the development of its planning standards. For information on the California ISO Transmission Planning Process, including the tariff language adopted by the Federal Energy Regulatory Commission and the California ISO Planning

The TPP is an annual process. In the most recent TPPs, the CPUC and CEC have provided renewable resource portfolios, a key assumption (e.g. a component of a scenario) to the TPP. Note that this sensitivity does not intend to modify the Memorandum of Understanding between the California ISO and CPUC on transmission planning assumptions. Under that Memorandum, CPUC will provide renewable resource portfolios to California ISO for use in the TPP.

Replicating TPP differs from the Base in several key ways. First, it applies a 1-in 5 peak weather condition, versus the Base Scenario's 1-in-2 peak weather condition. Also, the Mid forecast for energy consumption is used. There are limited to no impacts associated with future programs associated with energy efficiency or combined heat and power, and a low level of demand response. The RPS portfolio is the Commercial Interest case. Nuclear generation is assumed online throughout the planning horizon.

The Replicating TPP Scenario, however, departs in a fundamental way from the TPP by introducing retirement forecasts for existing generation based on the Mid values from the planning assumptions. Introducing retirement forecasts is consistent with concerns about future resource availability.

To the extent that the California ISO changes the core assumptions within the TPP, this scenario should be realigned to match those assumptions.

How to Get There: The *Replicating TPP Scenario* entails continuing RPS policy without significant change, while also terminating policies relating to preferred resources.

X. High Distributed Generation, High Demand Side Management Scenario

The Governor has made the adoption of distributed generation a priority.[33] This scenario was created to project the general implications of this state policy of promoting high amounts of distributed generation and demand side resources throughout the system.[34] This future represents a significant change to the pattern of generation and transmission development. Accordingly, this scenario may provide insight to

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Standards documents are available here: http://www.caiso.com/planning/Pages/TransmissionPlanning/Default.aspx. *See* ACR (R.)12-03-014, p. 5.

[33] *See* California's Path to 12,000 Megawatts of Local Renewables, Governor's Local Renewable Power Working Group Conference, Segmenting the Governor's Localized Energy Goal Panel, Discussion Paper #1: http://gov.ca.gov/docs/ec/ConferencePaper_regional_target.pdf.

[34] The High Distributed Generation, High Demand Side Management Scenario remains fundamentally the same as in the initial Energy Division proposed "High Distributed Generation Scenario". The name has been changed to better reflect the assumptions utilized in building this scenario.

policy makers into the resource needs associated with impacts of this shift in generation and transmission.

The High Distributed Generation, High Demand Side Management Scenario applies the High assumption for Small PV, by assuming a full uptake of demand side Small PV. It projects a strong increase in the quantities of Incremental CHP on both supply and demand sides via High assumptions, as well as a High level of DR. RPS procurement is shifted to High Distributed Generation (from the Base Scenario's Commercial case), while nuclear retirements apply the Low assumption with plants assumed online throughout the study horizon.

<u>How to Get There</u>: The *High Distributed Generation, High Demand Side Management Scenario* assumes the aggressive pursuit of CHP, Incremental Small PV, and DR policies. Also, it requires a change to RPS policy, preferring distributed generation resources to central station generation.

X.a. High Distributed Generation, High Demand Side Management, 40% RPS by 2030 Sensitivity

This sensitivity differs from the High Distributed Generation, High Demand Side Management Scenario by planning for the adoption of a 40% RPS target by 2030. Since the 33% RPS Calculator does not create sufficiently detailed annual portfolios for this analysis, a renewables net short for 2030 is calculated (see below in Section XI). The additional renewables in the resulting portfolio (i.e. with the higher 40% in 2030 renewables net short) relative to The High Distributed Generation, High Demand Side Management Scenario are assumed to be added in equal amounts each year from 2023 to 2030 (and continuing that growth beyond 2030). This scenario marks an effort to begin creating a body of analysis around the operational impacts associated with a higher RPS target beyond 2020. This sensitivity otherwise is identical to the High Distributed Generation, High Demand Side Management Scenario.

<u>How to Get There</u>: *The High Distributed Generation, High Demand Side Management 40% RPS by 2030 Sensitivity* assumes a change in current RPS targets to attain a 40% RPS by 2030, in addition to the changes for the High Distributed Generation, High Demand Side Management Scenario.

XI. The Second Planning Period: Years 11-22

As stated in the June 27th Assigned Commissioner's Ruling, the second planning period (2023-2034) 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 incremental EE, CHP, etc.), rather than extrapolating individual load or demand assumptions. The formula is:

$$GrowthRate = \left(\frac{NetLoad_{2022}}{NetLoad_{2012}}\right)^{\frac{1}{(2022-2012)}} - 1$$

  Where Net Load is the gross load forecast minus: incremental energy efficiency, incremental small PV, and incremental demand side CHP. This annual growth rate is then applied to the 2022 Net Load to calculate the Net Load for 2023-2034.

- 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 2022 value through the second planning period.

- Event-based DR will be calculated using the average, annual compound growth rate from the first planning period. This growth rate will be applied to calculate the value for each year in the second planning period. The same formula described above for the Net Load is used to calculate the growth rate for Event-Based DR.

- RPS resource additions will be calculated using the 33% RPS Calculator based on an assumption 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 the calculate a net load in 2030. For the purposes of the Scenario Tool, the incremental amount of RPS resources to reach the 2030 goal of 33% RPS is added in equal amounts each year from 2023 to

2030. Note that the planning area growth rate calculated in the Scenario Tool is applied to the statewide number in the Renewables Net Short calculation.

XII. What's Next?

In October 2012, policy comments from the parties on the revised scenarios are due. The Proposed Decision on scenarios is expected in November 2012. Next, the scenarios will be provided to the California ISO and all other parties by for use in operating flexibility modeling. After this modeling assessment is completed, the proceeding is expected to make a need determination and assesses the alternatives for filling any net short position. According to the schedule in the Scoping Memo, a need authorization to fill any net short would occur in 2013.[35] Further guidance may be issued by the Administrative Law Judge or Assigned Commissioner regarding the future schedule.

[35] ACR (R.)12-03-014, p. 7.

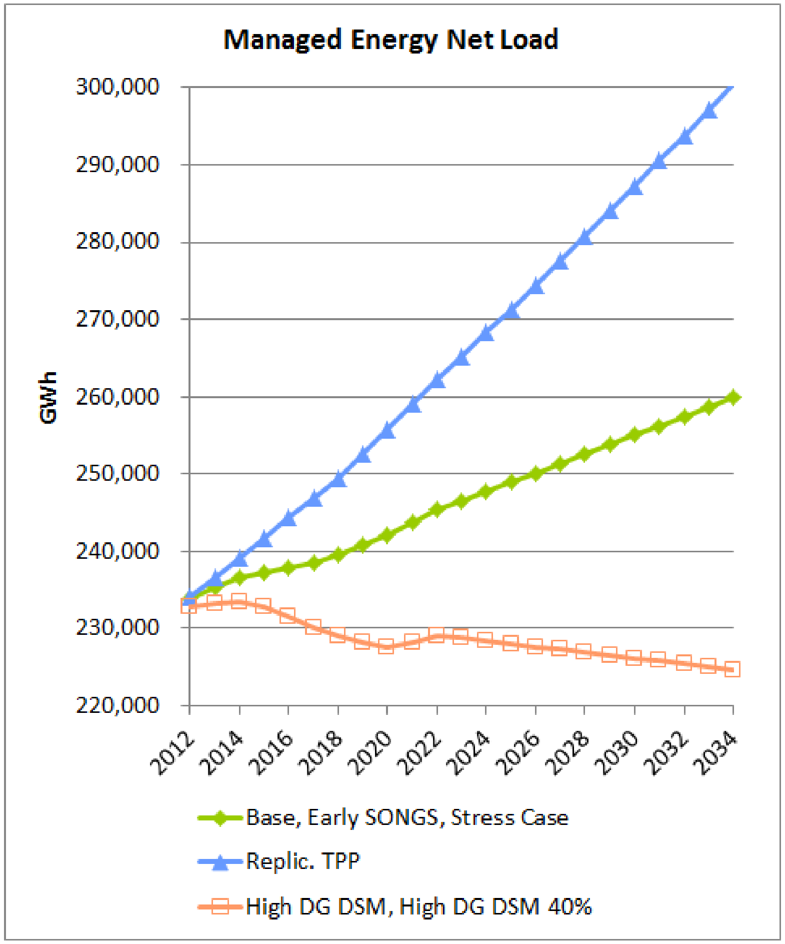
XIII. 2012 LTPP Scenario Matrix

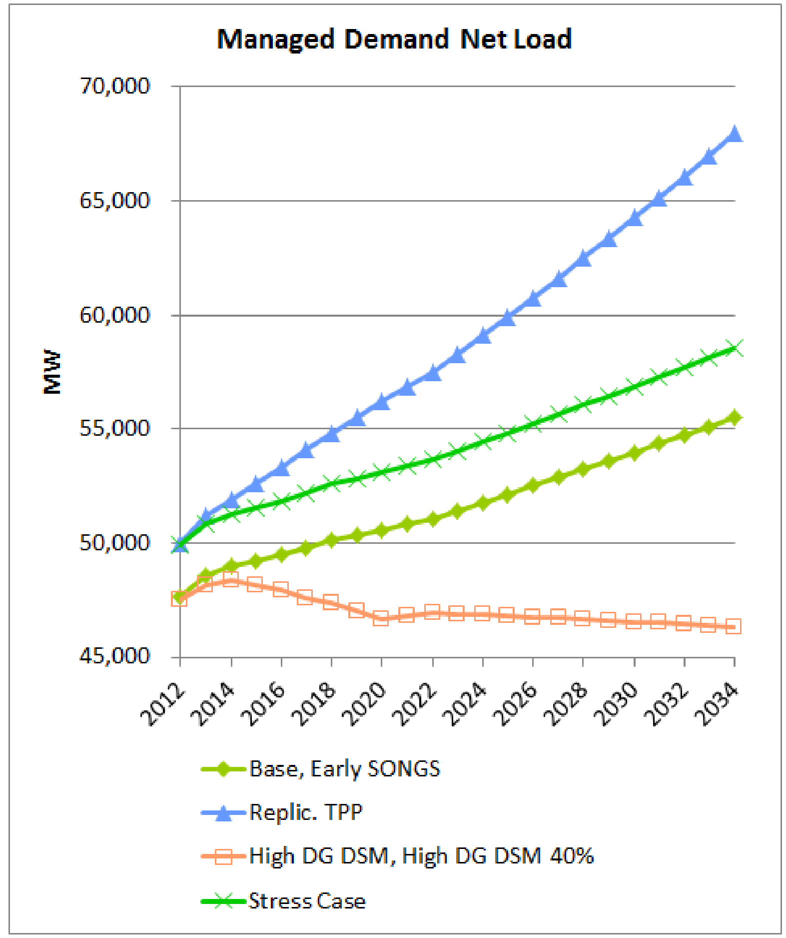
Recommended Priority Scenarios in Energy Division September Proposal are: Base, Replicating TPP, Early SONGS Retirement, and High DG + High DSM. Note that the colors in this table correspond to the colors used in the graphs below in Section XIV.

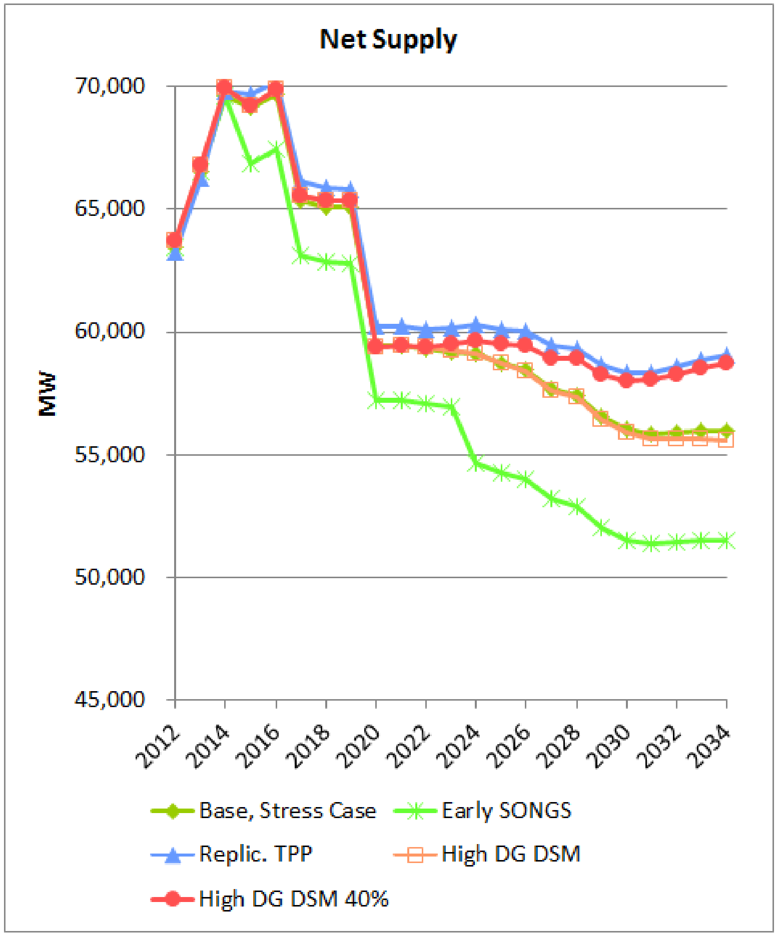
Scenario		Demand				Supply								
Name	**OpFlex Modeling Priority**	**Load**	**Inc EE**	**Inc PV**	**Inc CHP**	**Existing**	**Additions**	**Retirements**	**Solar + Wind & Hydro Retirements**	**Nuclear Retirement**	**RPS**	**Imports**	**Inc CHP**	**Inc DR**
Base	1	Mid	Mid	Mid	Low	Base	Base	Mid	Low	Low	Commercial	Base	Low	Mid
Replicating TPP	2	Mid (1-in-5 peak weather)	None	None	None	Base	Base	Mid	Low	Low	Commercial	Base	None	Low
Early SONGS Retirement	3	Same as Base				Same as Base				**Modified High (2015)**	Same as Base	Same as Base		
High DG + High DSM	4	Mid	High	High	High	Base	Base	Mid	Low	Low	High DG	Base	High	High
High DG + High DSM, 40% RPS by 2030	5 (if time allows)	Same as High DG + High DSM				Same as High DG + High DSM					**High DG, 40% RPS by 2030**	Same as High DG + High DSM		
Stress Case	6 (if time allows)	**Mid (1-in-5 peak weather)**	Same as Base			Same as Base								
Early Nuclear Retirement	7 (not at this time)	Same as Base				Same as Base				**High (2015)**	Same as Base	Same as Base		
Environmental	8 (not at this time)	Same as Base				Same as Base					Environmental	Same as Base		

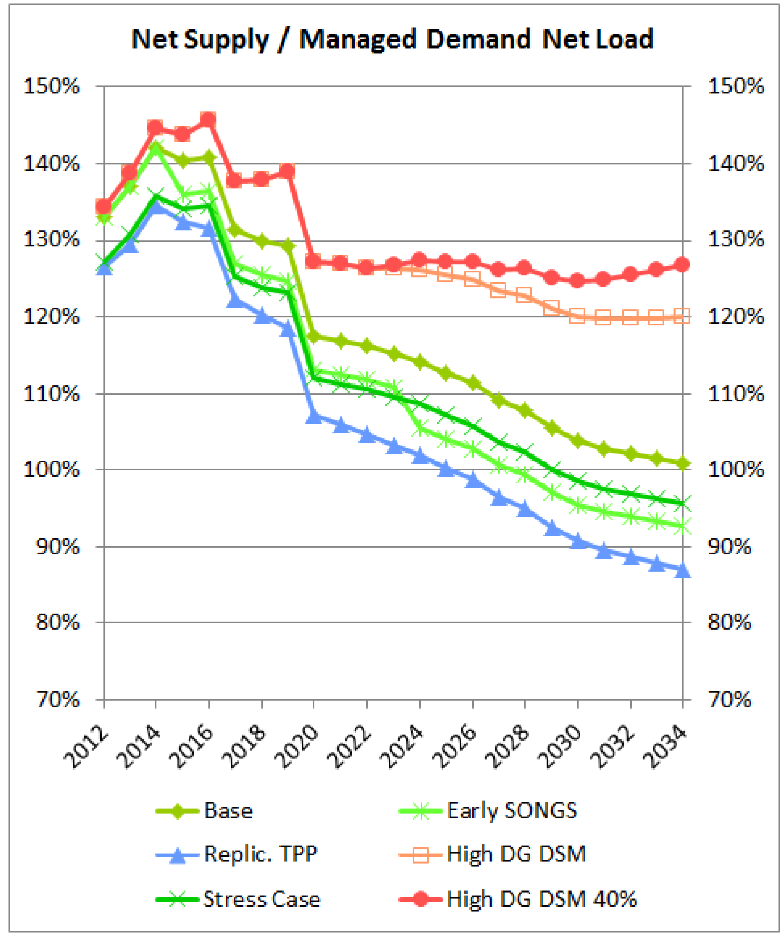
XIV. 2012 LTPP Scenario Charts

These charts provide a graphic depiction of the net load and supply in the various scenarios proposed. Note that in some of the graphs, multiple scenarios appear as a single curve because they are identical in that context.






Net Supply
MW
70,000
65,000
60,000
55,000
50,000
45,000
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
Base, Stress Case
Early SONGS
Replic. TPP
High DG DSM
High DG DSM 40%


Net Supply / Managed Demand Net Load
150%
140%
130%
120%
110%
100%
90%
80%
70%
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
Base
Early SONGS
Replic. TPP
High DG DSM
Stress Case
High DG DSM 40%

Appendix A. Technical Changes to the Straw Scenarios and Assumptions

On August 24, 2012, Energy Division Staff held a workshop to present scenarios for use in the 2012 LTPP. During the workshop, Staff discussed the revised 33% RPS Calculator, Straw Scenarios and the Scenario Tool[36], which was first introduced to parties via the electronic service list on August 13, 2012.

The Scenario Tool breaks down the individual supply and load assumptions and provides their corresponding numerical projections. It brings together data from a multitude of sources to comprise a hands-on model that allows parties to work with the values associated with the Standardized Planning Assumptions for the 2012 LTPP.[37] The Tool also provides the opportunity for parties to build their own scenarios by selecting individual supply and load assumptions to create a number of possible futures.

Staff requested that parties submit any technical comments on the Straw Scenarios and Scenario Tool by September 11, 2012. Below is a basic list of the changes Staff made to the Straw Scenarios and Tool to reflect the technical comments submitted by the parties.

1) Improve documentation
    - Describe primary data sources, what values are used to build a demand side or supply side assumption, and any adjustments to make the data usable within the accounting framework of the Scenario Tool.
    - Example of adjustment for CHP: ICF report[38] values are statewide, so we adjust those values downward by a factor equal to the ratio of the CAISO area to statewide 2011 net energy for load: 232220/285177 = 0.8143 ==> 81%.
2) Use the CEC Form 1.5 from the California Energy Demand Forecast 2012-2022 (CED), CAISO Coincident Peak Demand and Net Energy for Load to create the unmanaged demand forecast.[39]
3) Modify the "high" EE assumption to reflect BBEES in years 2015-2020, but use the low BBEES achievement forecast due to ongoing uncertainties around implementation and building stock turnover. Therefore, High EE is now calculated as savings + naturally occurring savings + low BBEES.

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[36] The Scenario Tool is available at: http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/ltpp_history.htm
[37] *See,* June 27, 2012 Assigned Commissioner's Ruling on Standardized Planning Assumptions, available at: http://docs.cpuc.ca.gov/PublishedDocs/EFILE/RULINGS/169732.htm
[38] http://www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002-REV.pdf
[39] http://www.energy.ca.gov/2012_energypolicy/documents/demand-forecast/Mid_Case_LSE_and_Balancing_Authority_Forecast.xls

- Detail of methodology: Use the low BBEES forecast from the 2009 Itron study published in 2010 regarding incremental EE relative to the 2009 IEPR. This data reflect a BBEES forecast for 2013-2020 in the IOU service territories. The cumulative impacts of 2013-2014 are subtracted from the forecast because those years' EE programs are already defined. The Scenario Tool requires a forecast to 2022 so the Tool assumes no new BBEES achievement in those two years.

4) Adjust Renewables Net Short in the 33% RPS Calculator to align with assumptions of the corresponding LTPP scenarios.
5) Adjust import capability assumption to exclude Existing Transmission Contracts outside the CAISO control area.
6) Provide further background on embedded Permanent Load Shifting (PLS) in scenarios:

   The CEC's demand forecast included a cumulative total of about 30 MW PLS for the three IOUs.[40] The CPUC has approved, however, a total of $32 million for approximately 50 MW of PLS for all three IOUs based upon the IOUs' respective 2012-2014 Demand Response applications submitted in April 2012.[41] Energy Division Staff considers this 20 MW differential between the CEC demand figure and the IOUs 2012-2014 Demand Response applications to be de minimis given the relative uncertainty surrounding the factors comprising the incremental analysis in the IEPR.
7) Correct the nameplate/installed capacity to peak production conversion (applies to D-CHP, S-CHP, and Inc Small PV).
   - The conversion factor is embedded in the self-generation PV data from California Energy Demand Forecast 2012-2022 (same methodology was used to calculate small PV capacity factor).

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[40] Email from Chris Kavalec, Demand Side Analysis Office, Electricity Supply Analysis Division, CEC to Noushin Ketabi, Generation and Transmission Planning, Energy Division, CPUC, *sent on* 8/30/2012 *at* 9:09am. *See also* http://www.energy.ca.gov/2012publications/CEC-200-2012-001/CEC-200-2012-001-CMF-V1.pdf at pp. 33-34.
[41] In the 2012-2014 DR applications, PG&E proposed a budget of $15 million for 27 MW of PLS, SCE proposed a budget of $14 million for 19 MW of PLS and SDG&E proposed a budget of $3.4 million for 3.6 MW of PLS storage. R.12-04-045, Decision Adopting Demand Response Activities and Budgets for 2012-2014 (April 19. 2012), p. 147, 226 Findings of Fact 60. The IOUs submitted updated numbers in August 2012 per D.12-04-05 which remained hovering around 50 MW total. On September 18th, a workshop was held to solicit party feedback to the IOUs' proposals. Email from Joanne Leung, Demand Side Programs, Energy Division, CPUC to CPUC Service Lists R.07-01-041, R.10-12-007, A.12-07-001 *et. al*, *sent on* 8-27-2012 at 11:16am.

- The option to use the CSI 2010 Impact Evaluation Report as the basis for installed capacity to peak production conversion is also available in the Scenario Tool.

8) Add latest CEC siting cases data to assumptions of non-RPS additions.
9) Add non-RPS additions sized < 50MW – based on CEC input and party comments to the extent possible.
10) No changes will be made to the event-based demand response forecast in the supply side assumptions. At this time, PG&E's peak time rebate program is still pending before the Commission, and any required savings are still unclear.
11) For existing resources with no documented commercial online date (COD), assume 1/1/2000 for retirement accounting purposes.
12) Account for non-OTC units known to have retirement dates attached to adjacent OTC units. These units are included on the OTC tab for retirement accounting purposes, but as noted, as not OTC units.
13) Correct the capacity of certain resources in the 33% RPS Calculator.
14) In the 33% RPS Calculator, adjust the relative amounts of Small Solar PV resources in the "South Coast" zone assumed to be part of the discounted core between the SCE and SDG&E service territories.

Appendix B. Updates to the 33% Renewable Portfolio Standard Calculator

Introduction

This Appendix describes the updates made to the 33% RPS Calculator between version 2 (v3) (published in May, 2012)[42] and version 3 (v3) (published in September, 2012). Background material on the 33% RPS Calculator is published on the Energy Division website.[43] The original 33% RPS Calculator was developed by Energy + Environmental Economics (E3); the majority of the updates in v3 were completed by Energy Division Staff. The major updates[44] are:

- Update to the California Renewable Net Short, consistent with each of the proposed scenarios
- Update to the list of generation projects
- Update to transmission information

Two implementations of v3 are published, called: v3 and v3_HighDG. The primary v3 was used to create two portfolios: Environment and Commercial Interest. The v3_HighDG was used to create a portfolio with high amounts of distribution-interconnected small solar photovoltaic generation (called the "High DG" portfolio) using the same weighting on the scores as the Commercial Interest portfolio. The difference between the two versions is that an additional 5,306 megawatts (MW) of distribution-interconnected small solar photovoltaic resources are forced into the portfolios produced by the 33% RPS Calculator, v3_HighDG.

Except as described below, no additional changes have been made to the 33% RPS Calculator relative to v2. Note that many parts of the 33% RPS Calculator have not been updated. In particular, some of the options available on tab **a – ControlPanel** are no longer fully operational (e.g. the different load forecast levels). Users wishing to develop portfolios using different assumptions through these options should be aware of these limitations and should carefully check the results.

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[42] http://www.cpuc.ca.gov/PUC/energy/Renewables/transmission.htm
[43] Ibid. See also: http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/LTPP2010/2010+LTPP+Tools+and+Spreadsheets.htm
[44] A list of changes is also included in the model itself on the **Changes** tab.

Updates to California Renewables Net Short

The California Renewables Net Short (RNS) is calculated on tab **ff – CA_RPSNetShortCalc**. The sources for the updated demand side inputs to the RNS calculation are from CEC's Adopted California Energy Commission Demand Forecast Report 2012-2022, including the estimates for incremental, uncommitted resources (shown in Table 1 below as "additional" values).[45] The load forecast remains constant, using a mid-case load for the three scenarios – the "Mid (1-in-5 peak weather)" load projection is the same as the mid-case load projection for energy demand purposes. Our estimates of existing renewables are based on the CEC's estimates, adjusted to exclude projects that were not online by summer, 2012 (equivalent to the August 1, 2012 Project Development Status Reports). These existing generation estimates do not include generation projects that are expected to retire, or to cease selling generation to California, before 2022. The estimates of existing generation do not include a resource degradation factor. In order to account for procurement already completed under certain CPUC-approved procurement programs (e.g. the Renewable Auction Mechanism), 1,110 GWh/year of energy from these programs is counted as existing generation (row 11 in Table 1) for the purpose of calculating each RNS, and are excluded from the 33% RPS Calculator. When calculating the different RNS amounts, certain CPUC-approved distributed generation procurement programs are considered as fully committed resources, and are either modeled through the discounted core (for resources that have not yet been procured), or are excluded from the 33% RPS Calculator and the RNS is reduced accordingly.[46]

The RNS projections included in Table 1 range from a low of 24,666 GWh/year to a high of 38,362 GWh/year. These RNS projections represent the remaining amounts of energy that are required to come one line in order to comply with the State's 33% renewable portfolio standard for a given scenario. Regardless of which RNS projections is chosen, the RNS amount will decrease overtime as new renewable projects are successfully connected to the grid and, in future iterations of the 33% RPS calculator, accounted for in the RNS calculation.

[45] http://www.energy.ca.gov/2012_energypolicy/documents/

[46] Version 2 of the 33% RPS Calculator incorporated all of the approved distributed generation procurement programs through the discounted core. None of the distributed generation was excluded from version 2 of the 33% RPS Calculator because none of the procurement had actually been completed by the time version 2 updates were finalized.

Table 1. 2022 California Renewables Net Short projections for a 33% RPS: Base Case, Replicating TPP Case, and High DG + High DSM Case

	All Values in GWh for the Year 2022	Base	Replicating TPP	High DG + High DSM
1	Statewide Retail Sales - June 2012 IEPR12 Final	301,384.0	301,384.0	301,384.0
2	Non RPS Deliveries (CDWR, WAPA, MWD)	12,530.0	12,530.0	12,530.0
3	Retail Sales for RPS	288,854.0	288,854.0	288,854.0
4	Additional Energy Efficiency	19,543.0	-	28,536.5
5	Additional Rooftop PV	2,158.8	-	5,480.0
6	Additional Combined Heat and Power	-	-	7,485.7
7	Adjusted Statewide Retail Sales for RPS	267,152.2	288,854.0	247,351.9
8	**Total Renewable Energy Needed For 33% RPS**	**88,160.2**	**95,321.8**	**81,626.1**
	Existing and Expected Renewable Generation			
9	Total In-State Renewable Generation	41,900.0	41,900.0	41,900.0
10	Total Out-of-State Renewable Generation	13,950.0	13,950.0	13,950.0
11	Procured DG (not handled in Calculator)	1,109.7	1,109.7	1,109.7
12	**Total Existing Renewable Generation for CA RPS**	**56,959.7**	**56,959.7**	**56,959.7**
13	**Total RE Net Short to meet 33% RPS In 2022 (GWh)**	**31,200.5**	**38,362.1**	**24,666.4**

The RNS projections for a 40% RPS by 2030, illustrated in Table 2 below, omit rows 1-6 of Table 1 due to the fact that the Energy Division incorporated growth rate factors directly into the "Adjusted Statewide Retail Sales for RPS" amounts (row 7). These growth rate factors for 2022 through 2030 are: 0.483%, 1.143%, and -0.163%[47], for the Base Case, Replicating TPP Case, and the High DG + High DSM Case, respectively. The Energy Division calculated these factors by manipulating the "scenarios" tab found in the LTPP Scenario Tool in order to create the corresponding scenario's growth rate factor (for purposes of load); the outcome of these calculations is shown in LTPP Scenario Tool – column O, cell 43 of the scenarios tab for every distinct projection. These 2030 projections assume the same existing renewable generation (rows 9-11) as the 2022 projections.

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[47] The negative growth rate factor (-0.163) in the High DG + High DSM Case is due to an accumulated increase in the Demand Side Management (DSM) forecast that is incorporated into the Scenario Tool in the later part of the 2012-2022 timeframe. This increase in forecasted DSM results in a lower managed 2022 energy net load total of 229,110 GWh compared to the 2012 starting point of 232,869 GWh.

Table 2. 2030 California Renewables Net Short projections for a 40% RPS: Base Case, Replicating TPP, and High DG + High DSM

	All Values in GWh for the Year 2030	Formula	Base	Replicating TPP	High DG + High DSM
7	Adjusted Statewide Retail Sales for RPS	incorporates assumed growth rate	277,651.2	316,348.0	244,144.7
8	**Total Renewable Energy Needed For 40% RPS**	**8=7*40%**	**111,060.5**	**126,539.2**	**97,657.9**
	Existing and Expected Renewable Generation				
9	Total In-State Renewable Generation		41,900.0	41,900.0	41,900.0
10	Total Out-of-State Renewable Generation		13,950.0	13,950.0	13,950.0
11	Procured DG (not handled in Calculator)		1,109.7	1,109.7	1,109.7
12	**Total Existing Renewable Generation for CA RPS**	**12=9+10+11**	**56,959.7**	**56,959.7**	**56,959.7**
13	**Total RE Net Short to meet 40% RPS In 2030 (GWh)**	**13=8-12**	**54,100.8**	**69,579.5**	**40,698.2**

Updates to "Energy Division Database" Projects

The updated "Energy Division Database" was created using data from the August 1, 2012 Project Development Status Reports (PDSR) filed by the Investor Owned Utilities (IOU) as well as from the response to a CPUC data request issued to the IOUs for some of the PDSR data that were submitted in a format that matched that of the 33% RPS Calculator. The PDSRs provide CPUC with updates on all RPS projects with which the IOUs have executed PPAs or have active negotiations for PPAs. This data was used to update tabs **I - CommProjData** and **j – GenericProjData** as described below.

Projects Included

Generation projects were selected to include in the database based on the following criteria:

Table 3. Included Projects

I – CommProjData	Executed or approved PPA or projects (e.g. solar PV programs) which do not require a PPA, complete application for major environmental permit
J – GenericProjData	Executed or approved PPA or projects (e.g. solar PV programs) which do not require a PPA, without complete application for major environmental permit

Projects with a capacity of 0 MW were excluded from the database.

In order to account for the distributed resource procurement programs (e.g. Renewables Auction Mechanism) that have procured specific projects, some of the distributed resources included in v2 of the 33% RPS Calculator were removed from v3. The specific 33% RPS Calculator resources most similar in location to the actual procured projects were removed, and the RNS was adjusted accordingly. As stated in Section 0, the total amount of these projects is 1,109.7 GWh/year. Not only were these projects not included in the 33% RPS Calculator, but equivalent amounts of the Local Distributed Photovoltaic (LDPV) were removed from the discounted core to avoid double counting (to avoid the possibility of "double counting" similar projects that may be mutually exclusive). These projects are summarized by location in Table 4.

Table 4. LDPV Removed to Account for Procured DG

Location	Procured DG (MW)	LDPV Capacity Removed (MW)
Central Valley	164.7	164.9
Mojave Desert	122.9	121.5
South Coast	134.5	134.2
North Coast	11.2	10.8
Total	433.3	431.4

Project Classification

The resource type and sub-type classifications were determined by the IOUs with the guidance of Table 5. These type and sub-type classifications categorize the specific resources into categories with defined parameters (e.g. capacity factor, cost, etc.) in the 33% RPS calculator.

Table 5. Resource Type and Sub-Type Classifications

Type	Sub-Type
Biogas	Biogas can be {blank} or "Landfill"
Geothermal	Geothermal is {blank}
Biomass	Biomass is {blank}
Wind	Wind is {blank}
Small Solar PV	Small Solar PV is: Large (<20,>5 MW), Mid (>1,<=5 MW), or Small (<=1 MW) Ground or "Large Rooftop"
Large Scale Solar PV	Large Scale Solar PV is "Thin-Film" or "Crystalline Tracking"
Solar Thermal	Solar Thermal is {blank} or "w/ storage"

Large scale solar PV projects with invalid or missing sub-types were classified as "Thin-Film".

The resource specific locations were determined by the IOUs based on the county of the project.

Table 6. Large Scale Solar PV Counties

Desert	Central Valley
Los Angeles	Tulare
Riverside	San Luis Obispo
San Diego	Kern
Yuma (AZ)	Kings
Clark (NV)	Fresno
Maricopa (AZ)	Merced
San Bernardino	Santa Barbara
Imperial	

Table 7. Small Scale Solar PV Counties

Central Valley	Mojave Desert	North Coast	South Coast
Kern	San Bernardino	Monterey	Los Angeles
Fresno	Riverside	Alameda	Santa Barbara
Madera	Inyo	Solano	San Luis Obispo
Kings	Mono	Contra Costa	San Diego
Mariposa	Clark (NV)	Santa Clara	Ventura
Merced		Marin	Orange
Tulare		Napa	
Tuolumne		Santa Cruz	
Stanislaus		Lake	
San Joaquin		Sonoma	
Amador		Mendocino	
Plumas		Humboldt	
San Benito		San Mateo	
Yolo		San Francisco	
Placer		Trinity	
El Dorado			
Sutter			
Butte			
Nevada			
Calaveras			
Glenn			
Colusa			
Yuba			
Tehama			

Shasta			
Sierra			
Sacramento			

Updates to Transmission Information

Energy Division Staff collaborated with California Independent System Operator (California ISO) staff to update the transmission data on tab **g – TxInputs**.

Updates to Available Capacity for New Projects

In order to account for the transmission capacity used by recently online projects, Staff calculated MW amounts of capacity to subtract from the existing estimates of capacity available on existing transmission, with and without minor upgrades (columns F and G).

Table 8. Recently Online Capacity by CREZ

CREZ	MW to Subtract	Available Capacity (MW)
Imperial	265	860
Inyokern	68	n/a
Palm Springs	285	0 (1,400 with Riverside East)
San Bernardino - Lucerne	9	253
Solano	335	0
Tehachapi	1,697	2,803
Twentynine Palms	2	n/a
Westlands	215	775

Combining Palm Springs and Riverside East

In order to reflect the shared transmission needs of the two CREZs, Palm Springs projects were relabeled as Riverside East. Effectively, these two CREZs are now merged for purposes of the 33% RPS Calculator.

Updates to the Location of Certain NonCREZ Resources

In an effort to promote continuity with the 2012-13 Transmission Planning Process, certain projects listed as “NonCREZ” in the data sources are treated as CREZ resources in order to account for their position on the transmission system. Only resources which would have substantially similar transmission impacts to the resources within one of the transmission zones were relabeled in this manner.

Table 9. California "NonCREZ" projects that are being treated as CREZ resources in order to account for their position on the transmission system

CPUCID	Project Name	MinCapacity (MW)	County	CREZ
PG0951	Starwood IID	195.00	Riverside	Imperial
PG0963	Corcoran	19.00	Kings	Westlands
SC1044	Industry Metrolink PV 1, LLC	1.60	Los Angeles	Solano
PG1011	Vasco Winds (Altamont Repowering)	78.20	Contra Costa	Solano
PG0712	Mt. Poso Cogeneration Plant (Redhawk)	44.00	Kern	Westlands
PG0606	Eden Vale Dairy	0.15	Kings	Westlands
PG0941	Avenal Park (Eurus)	6.00	Kings	Westlands
PG0968	Sand Drag (Eurus)	19.00	Kings	Westlands
PG0967	Sun City (Eurus)	20.00	Kings	Westlands
PG0705	San Joaquin Solar 1&2 (Bethel, Eviva)	107.00	Fresno	Westlands

(END OF ATTACHMENT)