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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 13-12-010 (Filed December 19, 2013)

ASSIGNED COMMISSIONER'S RULING ADOPTING ASSUMPTIONS AND SCENARIOS FOR USE IN THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR'S 2016-17 TRANSMISSION PLANNING PROCESS AND FUTURE COMMISSION PROCEEDINGS

This assigned Commissioner's Ruling adopts the attached standardized Assumptions and Scenarios for use in the California Independent System Operator's (CAISO's) 2016-17 Transmission Planning Process and for use in the Commission's next round of planning in our next Long-Term Procurement Planning and Integrated Resources Planning Rulemaking (R.) 16-02-007.

Commission staff has coordinated with the California Energy Commission (CEC) and the CAISO to recommend these Assumptions and Scenarios. The process is similar to the one used in previous years in this proceeding and its predecessors.

On February 8, 2016 the Administrative Law Judge (ALJ) provided that parties could comment on the staff proposed Assumptions and Scenarios. Parties commented on February 22, 2016 and replies were filed February 29, 2016. I thank the parties for their thoughtful comments. After consideration of these comments and in consultation with Commission staff, this ruling adopts the attached updated standardized Assumptions and Scenarios. The updates include the following key changes from the draft:

- **Section 4.1.4. Energy Efficiency**: the Senate Bill (SB) 350 additional achievable energy efficiency (AAEE) calculation that was initially included in the Draft document has been modified; this calculation now incorporates the 2015 mid-AAEE forecast and extrapolates years 2026-2030 using an assumed 3% growth rate.
- **Section 4.1.5. Solar Photovoltaics:** clarifications were made regarding the assumed attributes and treatment of behind-the-meter solar photovoltaics in modeling.
- **Section 4.1.6. Combined Heat and Power (CHP):** changes were made to clarify that only the behind-the-meter CHP components that are exported to the grid should be modeled as supply-side resources, as described in section 4.2.3.
- **Section 4.1.7. Demand Response:** the revised draft clarifies which demand response program impacts are assumed to be embedded within the CEC's demand forecast and which are not.
- **Section 4.1.9. Transportation Electrification**: a new section was added to the document that recognizes that the transportation electrification scenario included in the mid-demand case in the CEC's 2015 forecast is already aggressive.
- **Section 4.2. Supply-side Assumptions:** the revised attachment contains an improved description of how the forthcoming Scenario Tool will represent resource capacity in the context of the illustrative forecasts that are used to calculate planning reserve margin.
- **Section 4.2.3 CHP: includes the following clarifications:**
    - One half of the CHP export capacity will be assumed to operate on a historical profile basis and should be modeled as non-dispatchable.

    - The other half of the CHP export capacity will be assumed to be dispatchable by the CAISO.

- **Section 4.2.4 Energy Storage:** this section has been updated to include operational flexibility, resource adequacy, and 2-, 4- & 6-hour attributes of the transmission, distribution, and behind-the-meter ("customer-side") energy storage that has been procured to date. These assumptions have also been included for the residual energy storage procurement that still is necessary in order to reach the 1,325 Megawatts (MW) target of the large utilities. The document also includes a detailed explanation of the attribute assumptions that should be used for those storage projects procured in the future but which may not include explicit attribute-related information. Appendix B of the attachment further expands this attribute-related information for *each* energy storage project procured to date.

- **Section 4.2.5 Demand Response**: a comprehensive revision was incorporated with more detailed assumptions and modeling guidance regarding demand response capacity, based on existing utility programs, the demand response auction mechanism, and recent local capacity procurement. Also included is a comprehensive summary table illustrating total system demand response, by utility area and program, with assumed market participation and operational attributes.

- **Section 4.2.6 over-supply/over-generation:** this section has been revised for clarity.

- **Section 4.2.7 RPS portfolios –included are two new RPS portfolios:**

    - An RPS portfolio to be incorporated into the "Default Scenario – AAEE sensitivity" which incorporates a mid-AAEE level (and which therefore models higher net load and a higher associated RPS renewable net short than the Default Scenario. The Default Scenario incorporates the more aggressive SB 350 AAEE trajectory and therefore models a lower net-load).

   - An RPS portfolio that incorporates a higher 5,000 MW net export constraint (up from a 2,000 MW constraint in all other portfolios).

- Section 4.2.11 Renewable/Hydro Retirement Assumptions: a new chart is included (Table 21) detailing these assumptions.
- **Section 4.2.12 Other Retirement Assumptions**: the retirement **assumption** for the Long Beach Peakers has been revised.
- **Section 4.2.13 Imports and Exports**: the attachment clarifies that the Western Electricity Coordinating Council's Transmission Expansion Planning Policy Committee 2026 Common Case is to be the starting point for planning assumptions outside of the CAISO area. This section also specifies the numerical assumptions modelers should make when modeling net export constraints.
- **Section 4.2.14 Regional Generation Requirement and Frequency Response Constraints**: the title and text of this section has been revised. The previous "local minimum generation requirement" that was imposed on production simulation models is now removed and replaced with a new frequency response constraint, in order to represent system operations that are compliant with the new North American Electric Reliability Council's balancing standard (NERC BAL-003-1).
- **Section 4.2.15 Existing Procurement Authorizations**: Table 22 has been updated **with** Decision/Application numbers and the "approved" or "pending" status of each project.
- **Section 5.1 Scenarios**: the Transportation Electrification Scenario and the Low Load Scenario have been removed and a "Default Scenario – AAEE sensitivity" has been added; the priority of the scenarios has also been revised. One obvious change – the Infrastructure Investment Scenario is now the 9th scenario (before it was #1). This is because, regardless of "rank," this scenario will

be modeled by the CAISO for the 2016-17 Transmission Planning Process. Lastly, the name and description of the "Interregional Coordination Scenario" has been revised and now includes specific modeling guidelines assuming a combined CAISO and PacifiCorp balancing area.

Attached to this ruling is the updated document containing the final adopted standardized Assumptions and Scenarios. In addition, Commission staff is currently working on two companion items to assist parties conducting modeling and analysis:

1) **Scenario Tool.** In the past, the Scenario Tool was transmitted with the draft Assumptions and Scenarios inviting party comment, to assist in review of the document. Due to resource constraints, this procedure was not followed this year. However, Commission staff is still planning to make the Scenario Tool available, to allow parties to further examine individual assumptions in the attachment. When the Scenario Tool is available, anticipated to be by the end of May 2016, Commission staff will post the Scenario Tool to the following web link: http://www.cpuc.ca.gov/LTPP/. Staff will also send a courtesy email to the service lists of this proceeding and the new integrated resources planning and long-term procurement planning rulemaking R.16-02-007, alerting parties to the availability of the spreadsheet tool.

2) **RPS Calculator and RPS Portfolios.** Commission staff is also finalizing the RPS portfolios developed with the use of the most recent version of the RPS Calculator, as detailed in the attachment to this ruling. Once available, anticipated within a few days of the issuance of this ruling, the RPS portfolios will be posted to the following web link: http://www.cpuc.ca.gov/RPS_Calculator/. Staff will also send a courtesy email to the service lists of this proceeding, R.16-02-007, and the RPS rulemaking R.15-02-020, alerting parties to the availability of the RPS portfolios.

Should any minor technical errors in the standardized Assumptions and Scenarios and associated Scenario and RPS portfolio spreadsheet tools be discovered after this ruling is issued, I hereby direct the Commission's Energy Division Staff to collaborate with the staff of the CEC and the CAISO to correct the errors, notify parties of the corrections, and ensure that the corrections are applied consistently across each organization.

I also expect that, as the new integrated resources planning and long-term procurement planning rulemaking (R.16-02-007) begins its work, these Assumptions and Scenarios may need to be updated, certainly for the 2017-2018 Transmission Planning Process, if not earlier. Any such updates will take place in R.16-02-007.

IT IS RULED that the standardized Assumptions and Scenarios attached to this assigned Commissioner's Ruling are adopted for use in this Rulemaking 16-02-007, and the California Independent System Operator's 2016-2017 Transmission Planning Process.

Dated May 17, 2016 at San Francisco, California.

/s/ MICHAEL PICKER
Michael Picker
President

ATTACHMENT
Planning Assumptions & Scenarios For
The 2016 Long Term Procurement Plan Proceeding And
The CAISO 2016–17 Transmission Planning Process

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1 Introduction

The California Public Utilities Commission (CPUC or "Commission,") staff have prepared this 2016 Long Term Procurement Plan (LTPP) Assumptions and Scenarios (A&S) document in collaboration with staff from the California Energy Commission (CEC) and California Independent System Operator (CAISO). Included are nine scenarios which use one of six Renewable Portfolio Standard (RPS) portfolios.[1] These scenarios will help our agencies test for the overall impact that specific assumptions have on costs, Greenhouse Gas (GHG) emissions reduction and system reliability measures. This A&S document is being published within the 2014 Order Instituting Rulemaking R. 13-12-010 and is expected to be incorporated into the 2016 LTPP, R. 16-02-007.

As in previous LTPP cycles, this document provides demand-side and supply-side planning assumptions that should be utilized in the 2016 LTPP and, where appropriate, in the 2016-17 TPP studies. Demand-side assumptions are based on 2015 IEPR demand forecasts, which accounts for transmission and distribution line losses. Additional demand-side assumptions are provided, such as those addressing Senate Bill (SB) 350 energy efficiency impacts and recently procured in-front-of-the-meter Demand Response (DR).

The supply-side assumptions clarify which resources should be considered "existing" or additional to the resource fleet, how resource retirement dates should be calculated, and the assumptions that should be made regarding capacity and energy contributions of "imported and exported" resources. The supply-side assumptions also clarify which renewable resource portfolios should be assumed under the various study cases.

Shortly, the LTPP Assigned Commissioner, the President of the Commission, and the Chair of the CEC, will send a transmittal letter to the CAISO identifying which scenarios our joint agencies recommend should be studied in the Transmission Planning Process (TPP), including a recommendation of which scenario should be studied as the "base-case" in the 2016-17 TPP.

Unlike previous LTPP cycles, this document does not propose a trajectory scenario for the 2016 LTPP. The recent approval of SB 350 has made the trajectory of State policy clear on a broad basis, but additional development on specific modeling inputs is needed before a true trajectory scenario can be developed. Instead, we recommend adopting a Default Scenario that can be used to test certain modeling inputs and provide information for the development of a trajectory scenario at a later date. The Default Scenario, however, should not be regarded as representing the most probable California energy future; rather, the

[1] The six RPS portfolios are: a 33% portfolio that will be used in the 2016-17 TPP studies; a 50% by 2030 portfolio that is fully-deliverable; a 50% by 2030 portfolio that incorporates energy-only projects to reach the 50% RPS target; a 50% by 2030 portfolio that is fully-deliverable and which incorporates 3000 MW of wind resources from Wyoming; a 50% by 2030 portfolio that is fully-deliverable but that incorporates a Mid-AAEE trajectory (as opposed to an SB 350 AAEE trajectory); and a 50% by 2030 portfolio that is fully-deliverable which incorporates a net export constraint of 5000 MW (as opposed to 2000 MW).

Default Scenario should be considered as analogous to a "control group" of assumptions reflecting existing programmatic and energy policies that we will use to compare and contrast the differences between it and the other scenarios.

Parties to R. 13-12-010 were given an opportunity to provide comments and reply comments on the Draft A&S document.[2] The parties' comments were considered and taken into account, as reflected in this Final A&S document.

1.1 Terminology

Acronym	Definition
1-in-10	1-in-10 year weather peak demand forecast
1-in-2	1-in-2 year weather peak demand forecast
AAEE	Additional Achievable Energy Efficiency
AB	Assembly Bill
ACR	Assigned Commissioner Ruling
BTM	Behind-the-meter
CAISO	California Independent System Operator
CEC	California Energy Commission
CED	California Energy Demand Forecast
CHP	Combined Heat and Power
CPUC	California Public Utilities Commission or "Commission"
DCPP	Diablo Canyon Power Plant
DR	Demand Response
EE	Energy Efficiency
ELCC	Effective Load Carrying Capability
GHG	Greenhouse Gas
GWh	Gigawatt Hour
IEPR	Integrated Energy Policy Report
ILR	Inverter Loading Ratio
IOU	Investor Owned Utility
LCR	Local Capacity Requirement
LSE	Load Serving Entity
LTPP	Long Term Procurement Plan
MW	Megawatt
MWh	Megawatt Hour
NMV	Net Market Value

[2] Comments were submitted by February 22, 2016; reply comments were submitted by February 29, 2016.

NQC	Net Qualifying Capacity
OIR	Order Instituting Rulemaking
OTC	Once-through cooling
PG&E	Pacific Gas & Electric
POU	Publicly Owned Utility
PV	Photovoltaics
RFO	Request for Offers
RNS	Renewable Net Short
RPS	Renewable Portfolio Standard
SB	Senate Bill
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SWRCB	State Water Resources Control Board
TEPPC	Transmission Expansion Planning Policy Committee
TOU	Time-of-Use
TPP	Transmission Planning Process
WECC	Western Electricity Coordinating Council

1.2 Definitions

- **Load Forecast**: refers to the electricity demand served by the electric grid, measured by both peak demand and energy consumption. Load forecasts are influenced by a number of factors, such as State economics, demographics, behind-the-meter (BTM) resources and retail rates.
- **Assumption**: a statement that is made regarding the future for a given load forecast, or demand side or supply side energy resource, that should be used for procurement and transmission modeling purposes. For example, a forecasted load condition is an "assumption."
- **Scenario**: a complete set of assumptions defining a plausible California-centric energy future. Scenarios are driven by major factor(s) with impacts across many aspects of loads and resources. For example, a change in the energy load forecast would be considered a new scenario since the change would impact other variables including the amount of renewable projects and possibly transmission needs.
- **Portfolio**: is a component of the scenarios. Portfolios are the mix of resources to be modeled, created as a result of applying the assumptions in a specific scenario. For example, a RPS portfolio would include the specific RPS resources to be modeled, and would be developed based on the percentage of RPS resources required, the managed load forecast chosen, and a number of other variables.
- **Sensitivity**: is a variation on a scenario where only one variable is modified in order to assess its impact on the overall scenario results. Changing the retirement date of Diablo

Canyon Power Plant, while holding other assumptions constant, is an example of a sensitivity.

- **Managed Forecast**: refers to the California Energy Demand (CED) Forecast that has been adjusted to account for the impact of load modifying programs that are expected to come online but that are not embedded into the baseline load forecast. An example of a "managed forecast" is a situation in which we adjust the forecasted load in order to account for energy efficiency programs that are not yet funded but that are expected to be implemented over the course of the planning horizon – frequently referred to as Additional Achievable Energy Efficiency (AAEE).
- **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 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.

1.3 Background

The Long-Term Procurement Plan (LTPP) proceedings were established to ensure a safe, reliable, and cost-effective electricity supply in California.[3] A major component of the LTPP proceeding addresses the overall long-term need for new system reliability resources, including the need for resources that provide operational flexibility.

Due to the fact that the CAISO's annual Transmission Planning Process (TPP) and the CPUC's LTPP utilize similar planning assumptions, these assumptions should align and be consistent. In order to ensure this alignment and consistency between the LTPP and TPP planning assumptions, the CPUC updates the planning assumptions on an annual basis in coordination and collaboration with the CAISO and the CEC; this document contains those updates.

1.4 History of LTPP Planning Assumptions

Since the 2006 LTPP the CPUC has worked to make the long-term procurement planning process more streamlined and transparent. The main effort of the 2008 LTPP was the creation of the *Energy Division Straw Proposal on LTPP Planning Standards*.[4] The 2010 LTPP took strides towards implementing that proposal, with adjustments based on party comments. CPUC Energy Division staff held several workshops in the summer of 2010, and in December of that same year, the *2010 LTPP Standardized Planning Assumptions* were

[3] Pursuant to Assembly Bill (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.

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

issued via a Joint Scoping Memo and Ruling.[5] Following a similar process of workshops and comments in 2012 and 2013, the CPUC established LTPP planning assumptions for the 2012 and 2014 LTPP that build upon previous planning efforts to further improve the LTPP process.

2 Guiding Principles

The Guiding Principles[6] for developing assumptions to be used, and scenarios to be investigated, in the 2016 LTPP Rulemaking are:

A. **Assumptions** should take a realistic view of expected achievements from established policies while exploring potential impacts from possible policy changes.

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.[7]

E. **Scenarios** should be designed to contain useful policy information, for example tracking greenhouse gas reduction goals, and reliability implications of existing and expected resource procurement policies.

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

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

H. 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.**

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[5] *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

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

[7] 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.

3 Planning Scope: Area & Time Frame

The following assumptions and scenarios are created specifically with regards to the loads served by, and the supply resources interconnected to, the CAISO-controlled transmission grid and the associated distribution systems.[8] The LTPP planning period forecasts 20 years out in order to study the impacts of major infrastructure decisions under consideration. The long term nature of resource planning is necessary given that resources procurement decisions typically take three to nine years until fruition. While detailed planning assumptions are used to create an annual loads and resources assessment in the first 10-year period (2016-2026), more generic long-term assumptions are used in the second 10-year period (2027-2036), reflecting the greater uncertainties associated with forecasting a more distant future.[9] Nonetheless, each LTPP cycle considers the shorter-term (present to 10 years out) implications that infrastructure policy decisions have in conjunction with the longer term (10 to 20 year out) implications that each decisions carries.

This document supersedes the previous versions of assumptions and scenarios in this proceeding.

4 Planning Assumptions

A description of assumptions is provided in this section. All values will be reported in the 2016 Scenario Tool, a spreadsheet developed by CPUC staff to quantitatively present the load and resource assumptions for each of the scenarios described in this document. The most recent version is 2016 Scenario Tool version 1.[10]

4.1 Demand-side Assumptions

4.1.1 Baseline, Incremental, and Managed Forecasts

The LTPP uses the CEC-adopted CED[11] as its "baseline" forecast. Demand-side assumptions are either embedded in the baseline forecast or consist of adjustments made to the baseline forecast. Incremental resource projections, such as AAEE,[12] are not embedded in the baseline forecast, but can be used to modify the baseline forecast to create a net or "managed" forecast. As an example, in the CED the CEC embeds an amount of energy

[8] The technical studies will model the entire Western Electricity Coordinating Council (WECC); this document describes the assumptions that should be used for the balancing areas located inside the CAISO service territory. For assumptions pertaining to the balancing authorities located outside of the CAISO service territory, use the latest TEPPC common case data.

[9] The updates incorporated in this document will also inform the 2016-17 TPP studies.

[10] The Scenario Tool to be used in conjunction with the 2016 LTPP assumptions and scenarios is being updated. It will be posted on the CPUC LTPP webpage.

[11] See the CED: California Energy Demand 2016-2026 Forecast, http://www.energy.ca.gov/2015_energypolicy/

[12] The AAEE projections: estimates of Additional Achievable Energy Savings, Supplement to California Energy Demand 2016-2026 Forecast, https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-05

efficiency representing current codes and standards and established energy efficiency programs. AAEE represents future expected energy and capacity savings from programs not yet established or funded; as such, AAEE is considered an incremental resource projection to the Energy Efficiency (EE) embedded in the CED. In addition to its "baseline" demand forecast, the CEC publishes managed load forecasts which embed different levels of AAEE assumptions.

For modeling purposes the CEC provides its AAEE savings projections at the transmission bus-bar level to the CAISO; this information offers AAEE locational specificity to the CAISO and is provided on yearly basis for the given TPP's 10-year planning horizon.

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 that these resources provide to the system. Reliability studies in transmission-constrained local areas depend on these demand-side resources being capable of providing capacity value within the electrical areas in which they are forecasted to be located; ideally, their capacity value and location would be forecasted at specific transmission-level bus-bar or substation locations so that they can offset local capacity requirements in these subareas. Historically, demand-side resource projections lacked the locational certainty needed to contribute to local reliability. Fortunately, the current CED set of forecasts, with its embedded demand-side resources and incremental AAEE projections, is increasingly incorporating greater locational certainty by providing impacts at the climate zone level for BTM resources. The CEC defines 15 climate zones in California.[13] Efforts are underway to further refine the locational certainty of all BTM demand-side resources, to the transmission substation level, so that the capacity benefit provided by these resources can be appropriately counted on as a potential alternative to local conventional generation. [14]

4.1.3 Load

The CEC's 2015 Integrated Energy Policy Report (IEPR), which includes the CED set of forecasts, serves as the source for the "managed demand forecasts;" it consists of a base load forecast coupled with several alternative AAEE projections (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

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[13] See p. 51 of http://www.energy.ca.gov/2013publications/CEC-200-2013-004/CEC-200-2013-004-V1-CMF.pdf

[14] For the past three TPP cycles, the CEC staff have developed load bus projections of AAEE peak savings to enable the CAISO to include these savings in its power flow studies. These "translations" of the approved AAEE projections, for use in the TPP, are not explicitly adopted by the CEC.

variants, for example, 1-in-2 weather year and 1-in-10 weather year. The 2016 LTPP Scenarios incorporate the "Mid" load case.

While the CED forecast use the best available information, they do not include all future expected activity. For example, the 2015 CED base forecast does not include the impact of the CPUC's recently adopted rate changes. Additionally, the 2015 CED does not incorporate changes expected to result from the adoption of Senate Bill 350, since the legislation was passed too late in the process to revise the 2015 CED forecasts.

The 2015 IEPR CED forecasts do account for the electrification of the transportation sector. However, development of policies that drive higher electrification growth is underway and may result in a different level of penetration of electric vehicles (EVs) across all vehicle types, including rail electrification, than what is embedded in the 2015 IEPR base load forecast. The CEC published the full, adopted, 2015 IEPR CED forecasts in January 2016.

For planning studies that utilize an 8760 hour load profile as input, the load profile should have annual peak and energy values consistent with the CED forecasts for the year being studied. The base load profile should be adjusted by using CEC-provided AAEE load shapes described in the following subsection. For planning studies that utilize a single historical year as the basis for 8760 hour load shapes, the historical year should match the year used in the TEPPC 2026 Common Case.[15]

4.1.4 Energy Efficiency

Energy efficiency forecasts are developed from the CEC's 2015 IEPR CED base forecasts and its supplemental AAEE projections. Each load case of the CED base forecasts contains an embedded EE component that will be paired with an AAEE projection 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 AAEE projections. 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 aspirational goals (e.g. emerging technologies). Depending on the type of planning study, finer granularity of EE savings projections may be required.

Some planning study types may utilize EE savings projections allocated at the transmission-level bus-bar, and/or daily and seasonal load-shape EE savings projections. The CEC is developing 8760 load shapes for AAEE that match to the aggregate AAEE projections documented as part of the revised demand forecast. This task was undertaken so that modelers will not have to make up their own hourly shape, or debit it from peak and annual energy, and then effectively apply the same shape to AAEE as they do for the base forecast. We require that modelers use these 8760 hourly load reduction values when submitting studies to the CPUC, CEC or the CAISO. Transmission and distribution loss-avoidance effects shall be accounted in all studies.

[15] The TEPPC 2024 Common Case used the year 2005 as the basis for load shapes because it reflected an average weather year. TEPPC is considering using 2009 as the basis for load shapes in the 2026 Common Case.

The 2015 IEPR 1-in-2 and 1-in-5 weather year, Mid-Baseline-Mid-AAEE forecasts, should be used for the CAISO's system and bulk reliability studies in the 2016-17 TPP cycle.[16] The 1-in-10 weather year, Mid-Baseline-Low-AAEE forecast should be used for local reliability studies. The Mid-Baseline-Low AAEE scenario is appropriate for local reliability studies given the difficulty of forecasting load and AAEE at specific locations.

In order to approximate the AAEE envisioned by SB 350, modelers should use the GWh and MW values listed in Table 1. Appendix A provides the basic approach behind the SB 350 AAEE forecast. Since our objective is not to prejudge the energy efficiency goals that may emerge from the CEC's SB 350 energy efficiency target setting efforts that will not be completed until late 2017, but rather, to develop adjustments to the 2015 IEPR baseline demand forecast for modeling purposes, we modified the preliminary approach included in the Draft A&S document after reviewing of the parties' comments and in consultation with the CEC. Our starting point is the 2015 IEPR version of AAEE because, as noted by the CEC, some of the savings included in the 2014 IEPR version of AAEE are embedded the adopted 2015 baseline demand forecast. Using the 2015 IERP version of the AAEE will therefore avoid double counting this embedded AAEE. The methodology used to derive a SB 350 AAEE forecast now extends the growth of AAEE beyond 2026 using a 3 percent growth rate; doing so reflects some experts' concerns that more rapid AAEE growth may not be warranted as being cost-effective. The CPUC staff will work with the CEC staff to develop, in a manner consistent with the CAISO-wide aggregate energy efficiency savings: (1) the specific hourly values appropriate to production simulation modeling, and (2) load bus modifiers appropriate to power flow modeling to be used as part of this revised SB 350 AAEE forecast.

[16] See the "Infrastructure Investment Scenario" included in section 5.1 "2016 Planning Scenarios."

Table 1: SB 350 AAEE Projection GWh and MW

	Energy (GWh)	Peak (MW)
2016	1,750	472
2017	3,581	854
2018	6,234	1,435
2019	8,521	1,964
2020	10,877	2,541
2021	13,642	3,205
2022	16,568	3,906
2023	19,809	4,691
2024	23,194	5,534
2025	26,815	6,447
2026	30,678	7,430
2027	33,034	8,001
2028	35,505	8,599
2029	38,094	9,226
2030	40,806	9,883

4.1.5 Solar Photovoltaics

The CED forecasts embed the impacts of programs such as the California Solar Initiative. As such, the Mid BTM PV assumption included in this document assumes no change to the BTM PV embedded in the Mid-demand IEPR forecast; the Mid-demand IEPR forecast incorporates a Mid-level assumption for installed PV capacity.

A High BTM PV assumption forecasts a high incremental penetration of BTM solar PV relative to the Mid assumption (i.e. Mid-level PV capacity). Due to the higher BTM PV penetration, the associated GWh impact of using this assumption effectively lowers the Mid-demand IEPR forecast. The High BTM PV assumption that is incremental to the Mid BTM PV assumption is created as follows:

> 1) Subtract the Mid-level PV capacity embedded in the Mid-demand IEPR forecast from the High-level PV capacity embedded in the Low-demand IEPR forecast.
>
> 2) Add the capacity differential in #1 to the Mid-level PV capacity embedded in the Mid-demand IEPR forecast.

The High BTM PV assumption should be adjusted for transmission and distribution loss avoidance and includes the expected Megawatts (MW) of output at Investor Owned Utility

(IOU) system peak and the expected GWh of annual energy production for each year of the 2016-2026 timeframe being studied.[17]

Although BTM PV is generally regarded as a demand-side resource, both the CED forecast-embedded BTM PV and any incremental amounts could be modeled as supply resources (e.g. as a non-dispatchable resource with a fixed annual energy profile) in resource planning models. Under this modeling convention, the corresponding demand forecast assumptions in the resource planning model would need to be adjusted upward to remove the impact of BTM PV resources, since BTM PV resources would be separately accounted for as a supply-side resource. The appropriate upward adjustment would require adding back the peak and energy reduction impact of the BTM PV resources to the demand forecast. Production cost modeling often uses this modeling convention (modeling BTM PV as supply resources). Power flow models, such as used in the CAISO's TPP transmission planning studies may or may not use this modeling convention.[18]

The BTM PV resource assumptions described above are forecasts of the installed AC output of these resources, and reflect estimates of capacity contribution during IOU peak periods and annual energy production. The capacity contributions of BTM PV resources during IOU peak periods in different load areas are calculated by multiplying installed AC capacity by the "peak impact factor." In order to calculate the BTM PV resources annual energy production one must multiply the BTM PV resource "capacity factor" by the MW of installed BTM PV resource capacity and multiply the result by 8760 hours. The table below summarizes the IOUs' peak impact factor and capacity factor that should be used in resource planning studies. These factors are derived from the embedded BTM ("self-generation") PV resource assumption for each of the three major IOUs.

Table 2: Small Solar PV Operational Attributes

Variable	**PG&E**	**SCE**	**SDG&E**	**Average of all 3 IOUs**
Peak Impact factor	0.353	0.383	0.385	0.369
Capacity factor	0.191	0.202	0.200	0.197

[17] These adjustments are calculated in the Scenario Tool; transmission and distribution losses can also be found in Table 3 below (Section 4.1.9)

[18] The CAISO is considering modeling BTM PV resources as supply-side resources in both production cost and power flow models in the coming year. The CAISO may also allocate BTM PV resources to transmission bus-bars in proportion to load for a given load area, but is also discussing with Participating Transmission Owners of the possibility of using a more refined method.

The physical configuration of BTM PV resources influences the shape of hourly generation profiles and has material impact on the outcome of resource planning studies that inform the TPP and the LTPP. Two important physical attributes are the PV mounting type and the DC-AC inverter loading ratio. For BTM PV resources, the Mid assumption for mounting type is fixed-tilt, south-facing. The ratio of panel capacity to inverter capacity is the "DC-AC inverter loading ratio;" a higher loading ratio tends to flatten or clip the production profile of a PV unit. Industry practice for PV installations has been to install a panel capacity larger than the inverter capacity in order to compensate for de-rate factors such as DC-AC conversions and losses and to maximize economic value. For BTM PV resources, the Mid assumption for DC-AC inverter loading ratio is 1.2,[19] which is consistent with the assumption used in the Transmission Expansion Policy Planning Committee (TEPPC) Common Case.[20]

Granular information on the location and physical attributes of installed BTM PV resources can be derived from public databases such as those found on the "Go Solar California" web portal.[21] However, CPUC staff believes the benefit of incorporating such granular information in LTPP modeling is small because the overall uncertainty in BTM PV aggregate installed capacity in the long term is a much larger driver of modeling results. Therefore CPUC staff defers consideration of this granular information to a future LTPP cycle.

As mentioned above, models such as hourly production simulation models need to model BTM PV as a supply resource with a fixed profile, rather than as a load reduction in order to account for the hourly shape of solar generation. The source of underlying irradiance profiles and method for creating 8760 hour generation profiles for BTM PV should be documented by the modeler. The 8760 hour generation profiles should also be consistent with the technical attributes described above: fixed-tilt, south-facing, and DC-AC inverter loading ratio 1.2. By building 8760 hour generation profiles according to the BTM PV installed AC capacity assumptions that are included in the Scenario Tool and which reflect the technical attributes specified in this subsection, the resulting annual energy production implied by the profiles may deviate slightly from the annual energy production forecasted by using the capacity factors in Table 2. We expect any such deviation to be small and direct modelers not to adjust the profiles to perfectly match the annual energy production forecast in the Scenario Tool; rather, modelers should match the installed capacity forecast in the Scenario Tool.

[19] For BTM PV technology assumptions, the RPS Calculator uses the default settings of the National Renewable Energy Lab's PV Watts tool, including DC to AC size ratio of 1.1, fixed-tilt, and azimuth south-facing.

[20] https://www.wecc.biz/TransmissionExpansionPlanning/Pages/Datasets.aspx

[21] https://www.californiasolarstatistics.ca.gov/

4.1.6 Combined Heat and Power

The CEC traditionally forecasts a "consumption" energy demand forecast and then subtracts onsite self-generation, such as behind-the-meter Combined Heat and Power (CHP) generation, in order to compute the net energy for load. As such, the default assumption for BTM CHP resources assumes no change from what the CED forecasts embed. The BTM CHP resource capacity that does not export to the grid will not be modeled as a supply resource; its impact will be implicitly modeled by virtue of being embedded in the CEC load forecast. Any CHP resource that serves both BTM load and exports to the grid (or in some cases which only exports to the grid) will have its export component (net of the capacity and energy used onsite) modeled as a supply resource, as described in Section 4.2.3.

4.1.7 Demand Response

The CED forecasts embed the impacts of load-modifying[22] demand response (DR) programs. These programs are generally non-event-based and/or tariff-based and include existing Time-of-Use (TOU) rates,[23] Permanent Load Shifting, and Real Time Pricing. Certain event-based, price-responsive programs are also embedded in the CED forecasts and include Critical Peak Pricing and Peak Time Rebate programs.[24]

There may also be additional DR impacts that need to be explored. For example, a future DR impact may come from defaulting residential customers to TOU rates.[25] Commission staff will collaborate with CEC's staff to facilitate the study of the default residential customer TOU rate impact in the next major CEC IEPR planning cycle.

4.1.8 Energy Storage

Energy storage units shall be modeled as supply-side resources; therefore this document describes the planning assumptions for distribution-connected and customer-side storage, as well as transmission-connected storage, within the "Supply-side Assumptions" section.

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[22] See D.14-03-026 in the Demand Response Rulemaking, R.13-09-011, for further background on "load-modifying" and "supply-side" DR programs and the meaning of these terms with respect to DR resource attributes.

[23] The latest CED forecasts embed the impact of the TOU rates and periods existing in 2014, as they were forecast in the IOU's April 2015 load impact reports. These do include: (for residential customers) continuation of the TOU rates existing in 2014, with essentially no growth in participation – no default – and no late-shift in TOU periods; and (for non-res customers) mandatory TOU but no late-shift in TOU periods.

[24] DR programs whose impacts are *not* embedded in the CED forecasts include several event-based, price-responsive and reliability programs. Within the LTPP planning horizon, these programs shall achieve full integration into the CAISO wholesale market and therefore count as supply-side DR. Section 4.2.5 describes assumptions about DR treated as supply-side resources.

[25] The CED forecasts embed the impacts from existing TOU rates but do not include potential impacts from TOU rate changes being considered such as default TOU rates and shifting price periods/seasons.

4.1.9 Transportation Electrification

The CED Mid-demand case IEPR forecast includes a fairly aggressive transportation electrification assessment reflecting the best available California specific EV penetration information. This forecast, which is based on current policy trends, includes transportation electrification impacts that are expected by 2026. In CPUC staff's opinion, it is unlikely that an even higher transportation electrification scenario would materialize than what is already assumed in the Mid-demand case IEPR forecast. As such, the default transportation electrification assumption included in this document assumes no change to the transportation electrification assumption that is embedded in the Mid-demand IEPR forecast.

4.1.10 Avoided Transmission and Distribution Losses

Demand-side resource projections need to account for avoided transmission and distribution losses when calculating the balance of projected supply and demand. The table below specifies factors supplied by the CEC for accounting of avoided transmission and distribution losses. These factors are applied to the demand-side resource projections in order to determine the avoided supply-side generation replaced by the presence of demand-side resources.

Table 3: Factors to Account for Avoided Transmission and Distribution Losses

	PG&E	SCE	SDG&E
Peak, distribution losses only	1.067	1.051	1.071
Peak, transmission and distribution losses	1.097	1.076	1.096
Energy, transmission and distribution losses	1.096	1.068	1.0709

4.2 Supply-side Assumptions

All supply-side resource assumptions are solely for planning study purposes. Inclusion or exclusion of a specific project or resource in the planning cycle has no implications on existing or future contracts. To the extent a specific project or resource turns out to not be available, the planning study assumes an electrically equivalent resource will be available. All supply-side resources should be categorized as either a local resource (specific to a local area), a generic system resource, or a non-CAISO resource. At this time, no degradation of resource production is accounted for in these planning assumptions.

<u>Resource Representation in Planning Models</u>

A variety of planning studies can use the supply-side resource assumptions described by this document. Production simulation models should use the actual physical resource attributes of the supply-side (as well as demand-side) resource portfolios specified by this document. Power flow (load flow) and stability studies such as those used in the CAISO's TPP should continue current practices of translating actual physical resource attributes into expected resource output levels under the specific conditions being modeled in such studies.

For variable energy resources such as wind or solar energy resources, hourly production simulation models should use 8760-hour generation profiles for modeling production. The source of the underlying wind and irradiance profiles, and the method for creating the 8760-hour generation profiles, should be documented by the modeler. The 8760-hour generation profiles should also be consistent with the resource technologies and locations specified in the renewable resource portfolios described in Section 4.2.7 and (for solar PV) the specific technical attributes described in Section 4.2.8.

In the power flow (load flow) and stability studies typical of the CAISO's TPP, a required input is the expected output level of variable resources under the specific conditions being modeled, usually a specific time-of-day during a particular season. The CAISO has historically relied on one of two mechanisms for calculating the expected output level.

One mechanism uses the 8760 hour generation profiles for variable resources, described above; this mechanism requires extracting resource output levels corresponding to the time period being studied (e.g. peak, off-peak, partial peak, and light load base cases). The other mechanism relies on the historical Net Qualifying Capacity (NQC) of a variable resource (calculated in the Resource Adequacy proceeding using an exceedance methodology) as the basis for the expected output level from variable resources that share similar technological and locational attributes during the specific conditions being studied.

This document provides no additional guidelines for modifying the current modeling practices associated with the output levels of variable resources. The CPUC is actively considering the use of Effective Load Carrying Capability (ELCC) methods, which assigns capacity value to wind and solar resources. The ELCC could be used for system-wide studies that assess the reliability contribution of a resource over the course of an entire year. The Resource Adequacy proceeding will determine how the use of ELCC methods will inform NQC calculations for the purpose of system and/or local Resource Adequacy compliance. For 2016-17 TPP modeling purposes, the current Resource Adequacy exceedance methodology should continue to be utilized to model output levels of variable resources in the power flow (load flow) and stability studies typical of the CAISO's TPP.

<u>Capacity Representation In The Scenario Tool</u>

Simple annual load and resource tables, such as the Scenario Tool Excel workbook described by this document, are generally used as an illustrative assessment of system planning reserve margin up to 20 years into the future. The Scenario Tool stacks up the capacity of supply-side resources using the existing or expected NQC of a resource, or portfolio of resources, for the month of August (August is the usual month of system peak capacity needs). To the extent that NQC accounting methodologies change in the future, those changes should be reflected in subsequent LTPPs.

In the Scenario Tool load and resource table, the capacity representation of both existing and new renewable resources is replaced with the portfolio ELCC representation provided as an output of the RPS Calculator Version 6 and later. The simple annual load and resource table should use the ELCC methods to represent the contribution of renewable capacity toward maintaining system-wide reliability. Because the CPUC is expected to adopt ELCC methods for establishing the system-wide RA capacity value of variable resources in the near future, it is reasonable to also use these ELCC methods for an illustrative assessment of system planning reserve margin up to 20 years into the future. Historically, the Scenario Tool represented existing renewable capacity with its aggregate August NQC value, and new renewable capacity with an estimated NQC value generated by RPS Calculator Version 5 or earlier. RPS Calculator Version 6 and later does not produce such NQC estimates, but instead produces a single portfolio ELCC representative of both existing and new renewable resources for a given portfolio and year. In other words, the single portfolio ELCC represents all renewable resource types, in that portfolio, for that year. The ELCC representation changes from year to year as the portfolio adds (or retires) units through the years of the RPS Calculator's planning horizon. Thus, the 2016 Scenario Tool will remove the NQC representation of existing renewable resources and replace it with the portfolio ELCC representation of both existing and new renewable resources (which changes year to year) that the RPS Calculator Version 6 or later produces.

CPUC staff acknowledges that the above methodology is a crude estimate of reserve margin, which essentially stacks up the NQC values for non-renewable resources along with the ELCC values of an entire renewable portfolio. Nonetheless, it should be stressed that the ELCC values used in the Scenario Tool and the resulting planning reserve margins are illustrative. They are not intended to be used to forecast near-term ELCC values. Near-term ELCC values will be determined by rigorous modeling methods within the RA proceeding.

4.2.1 Existing Resources

In the 2016 Scenario Tool, the capacities of existing resources are represented by the monthly NQC values found in the 2016 Resource Adequacy compliance year NQC list. The CAISO and CPUC both publish these lists annually on their respective websites. As noted above when calculating a planning reserve margin, the Scenario Tool will represent the system-wide capacity value of both existing and new renewable resources using the yearly portfolio (cumulative) ELCC provided as an output of the RPS Calculator, version 6 and later. This means that in the planning reserve margin calculation, the NQC value of both existing and new renewable resources will be replaced with a portfolio ELCC-based representation that covers both existing and new renewable resources.

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.[26] 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/or (3) has begun construction. A power plant project that does not meet these criteria may be

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

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

Combined Heat and Power resources identified in this section export electricity to the grid.[27] The default projection for exporting CHP assumes that all retiring CHP resources less than or equal to 20 MW that are on the 2016 NQC list would be replaced on a one-to-one basis by similar CHP resources; CHP resources that are greater than or equal to 20 MW will be assumed to retire based on the same methodology used for non-OTC conventional generation reflected in the Scenario Tool.[28]

Exporting CHP resources will be modeled as follows. First, one half of the exporting CHP capacity of each CHP resource will be assumed to operate on a historic profile as reflected by its monthly values on the 2016 NQC list and should be modeled as non-dispatchable resources. Secondly, the remaining half of the exporting capacity of each CHP resource will be assumed to be resources that are dispatchable by the CAISO.

4.2.4 Energy Storage

CPUC Decision (D.)13-10-040 established a 2020 procurement target[29] of 1,325 MW of newly installed energy storage capacity within the CAISO planning area. Of that amount, 700 MW needs to be transmission-connected, 425 MW needs to be distribution-connected, and 200 MW needs to be customer-side-connected. Unless otherwise noted via the IOUs' energy storage Applications, CPUC staff has assumed that 40% of the megawatts associated with transmission-connected and distribution-connected projects will provide two-hour storage, 40% of these projects' megawatts will provide four-hour storage, and the remaining 20% will provide six-hour storage. For energy storage projects connected on the "customer-side" – that is, behind-the-meter – CPUC staff assumes that 50% of these projects' megawatts will provide two-hour storage and 50% will provide four-hour storage.

Additionally, D.13-10-040 allocated a portion of the 1,325 MW energy storage procurement target to each of the three major IOUs.[30] Energy storage that is operational after January 1, 2010 and no later than December 31, 2024 shall count towards the procurement target. The default planning assumption will continue to conservatively account for the expected

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27 The NQC list includes values for only that portion of the exporting CHP facility that is used to export. For example, if a CHP facility has a 100 MW capacity and 40MW of that capacity is dedicated to meet onsite energy consumption, the NQC list only reports NQC values associated with 60 MW of that facility.

28 That is, they are assumed retired based on a 40 year life cycle, or contract expiration date (whichever is furthest out).

29 The Decision specifies that resources must be online by 2024 so in the planning assumptions, target amounts are reached in 2024.

30 The CPUC also established an additional procurement target of 1% of load for ESPs and CCAs. The storage assumptions included herein do not include ESPs' or CCAs' storage resources.

contribution of operational flexibility and reliability capacity attained from the 1,325 MW energy storage procurement target. It is assumed that there will be no further growth in energy storage capacity targets, post 2024, beyond 1,325 MW.[31] Energy storage resources that are procured to satisfy a local capacity requirement also count towards satisfying the 1,325 MW energy storage target. Because such projects satisfy the local capacity RA requirement, they should be modeled as having a four-hour storage attribute; this assumption has been incorporated into the megawatts represented in Appendix B.

Assumptions about storage attributes and capabilities

The entire 1,325 MW energy storage target can provide energy services and should therefore be modeled as such in studies involving production cost simulations. Energy storage technology's ability to provide capacity and flexibility (load-following, ancillary services, etc.), however, depends on its visibility and controllability by the CAISO.

Transmission-connected energy storage will likely interconnect to the system near transmission substations and will, as a result, likely be visible and controllable by the CAISO. Therefore, the entire 700 MW target of transmission-connected energy storage is assumed to provide operational flexibility services to the grid; production cost modeling simulations should model it as such.

In regards to Resource Adequacy capacity used in power flow studies, all of the transmission-connected energy storage projects should be assumed to provide RA capacity – with the exception of two-hour storage facilities: only 50% of the MW associated with two-hour, transmission-connected, storage projects should be assumed to provide RA capacity. This exception reflects an assumed 50% derating of capacity value of two-hour storage needed to reflect these projects' ability to sustain maximum output for four-hours, per RA accounting rules.[32]

The ability of ***distribution-connected*** energy storage to provide capacity and flexibility to the grid carries more uncertainty, in part, because this technology is new to the market, and in part because current policy and the CAISO market is still being developed to

[31] Decision 16-01-032 allows the IOUs to satisfy some of their transmission and distribution domain targets through customer-connected projects, up to a "ceiling" of 200% of the existing customer domain targets. A SCE data request response on this topic indicated that SCE has storage in response to LCR requirement that in effect over-procured a cumulative amount of 95MW of customer-side storage – see Table 8. SCE's customer-side storage target is 85 MW; meaning that 85 MW can be allocated to other energy storage domains . Even after the permissible shift of 85 MW, SCE exceeds its 85 MW customer-side target by 10 MW. As such, the expected statewide energy storage is 1,335 MW, although for simplicity's sake our "Residual Energy Storage Procurement To Meet D.13-10-040 Targets (MW)." Table 6, is based on the adopted 1,325 MW target.

[32] For example, a storage project with 10 MWs of 2 hour storage would be considered 5 MW of RA capacity since it is assumed the project could sustain maximum output of 5 MW for four hours.

facilitate the participation of distribution-connected resources.[33] Therefore, the default assumption is that only 50% of the 425 MW of new distribution-connected energy storage will provide operational flexibility services to the grid.

In regards to RA capacity the following assumptions (unless otherwise stated in the IOUs' Applications) are made for all distribution-connected energy storage projects: 50% of the MW associated with these projects will provide RA capacity; similar to transmission-connected two-hour energy storage projects, the amount of RA capacity assumed for two-hour distribution-connected energy storage projects will be *further* derated by 50%, reflecting these projects' ability to sustain maximum output for four-hours.

Notwithstanding that SCE's 2014 LCR RFO resulted in 164 MW BTM storage (135 MW of which will provide "four-hour" storage capabilities,[34] enabling it to provide RA capacity), the ability of ***customer-side*** energy storage to provide RA capacity and flexibility carries even more uncertainty than distribution-connected storage. As such, we continue to make the conservative assumption that the *additional* customer-side energy storage projects the will be procured will not provide RA capacity or operational flexibility services to the grid.

Table 4: Decision 13-10-040 Energy Storage Target (MW)

Domain	Transmission-connected	Distribution-connected	Customer-side
Total Installed Capacity	700	425	200
Amount providing RA capacity in power flow studies	560	170	0
Amount providing flexibility	700	213	0
Amount with 2 hours of storage	280	170	100
Amount with 4 hours of storage	280	170	100
Amount with 6 hours of storage	140	85	0

[33] See CAISO's metering and telemetry options initiative; the Distributed Energy Resource Provider (DERP) initiative; the Energy Storage & Distributed Energy Resource (DERP) initiative; and the Flexible Resource Adequacy Criteria and Must Offer Obligations (FRACMOO) Phase 2.

[34] The remaining 29 MW consists of the "Ice Bear" project, a permanent load shifting thermal storage resource that, in power flows studies, should be modeled with a discreet negative load in the amount of -14.32 MW each at Johanna and Santiago 66kV bus.

Table 5: Total Energy Storage Procurement To-Date (Based On IOU Data Received In Early 2016)

Domain	Transmission-connected	Distribution-connected	Customer-side
SDG&E	60	6	13
SCE	0	132	180[35]
PG&E	60	21	0
Totals	**120**	**160**	**193**

Table 6: Residual Energy Storage Procurement To Meet D.13-10-040 Targets (MW)

Domain	Transmission-connected	Distribution-connected	Customer-side
Total Installed Capacity	580	265	7
Amount providing RA capacity in power flow studies	464	106	0
Amount providing flexibility	580	133	0
Amount with 2 hours of storage	232	106	4
Amount with 4 hours of storage	232	106	4
Amount with 6 hours of storage	116	53	0

In the CAISO's TPP Base local area reliability studies the transmission bus-bar identification numbers, names, etc., included in Table 7, Table 8 and Table 9, below, should be used for locational information regarding energy storage resources located in PG&E's,[36]

[35] SCE's customer-side storage target is 85 MW; meaning that, SCE procured 95MW more customer-side storage than needed to reach the target. Per energy storage rules, 85 MW of the over-procured MW can be allocated to other energy storage domains. Modelers should allocate 42.5 MW to each of the transmission and distribution domains.

[36] PG&E explained the following in regards to the energy storage resources listed in the "PG&E Energy Storage Resources" table: "The majority of the projects listed did not have completed interconnection studies nor were they included in the CAISO Full Network Model at the time of offer submittal. The list has also not been confirmed with

Footnote continued on next page

SCE's and SDG&E's service territories. Appendix B includes an expanded version of these three charts, which assigns RA capacity, operational flexibility capacity and storage hours attributes (two, four, or six) to these projects; actual known RA capacity, operational flexibility capacity and hourly values pertaining to those projects for which the IOUs reported this information, are included.

<u>Summary: Energy Storage Assumptions Regarding RA, Flexibility and Depth/Duration used when project details are not know</u>

Transmission-connected energy storage projects:

- All megawatts count for RA except:
    - If the energy storage project has a two-hour depth then it is derated by 50% in order to convert it MW into the amount of capacity actually counting towards RA (since by RA rules output must be sustained for minimum four-hours)
- All megawatts are assumed to provide operational flexibility to the grid
- For those projects whose duration/depth information was unavailable, we assume that 40% of their cumulative total megawatts provide two-hour storage, 40% provide four-hour storage, and 20% provide six-hour storage

Distribution-connected energy storage projects:

- If the energy storage project was procured in order to satisfy a local capacity requirement (LCR), all of that capacity counts towards RA (because such capacity has to be at least four-hours depth/duration), but only 50% of this capacity is assumed to provide operational flexibility to the grid
- If the energy storage projects does not help satisfy a LCR, 50% of this capacity is assumed to count for RA, unless:
    - It only provides two-hour storage depth, in which case it is further derated by 50% in order to convert its capacity into an amount that can count towards meeting the RA obligation (since by RA rules output must be sustained for minimum four-hours)
- 50% of the megawatts, regardless of their RA contribution, are assumed to provide operational flexibility to the grid
- Energy Storage projects for which no duration/depth information was made available, we assume 40% of their cumulative total megawatts provide two-hour storage, 40% provide four-hour storage, and 20% provide six-hour storage

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the CAISO. Therefore the list is PG&E's current estimate of the nearest Transmission Point of Delivery / Receipt, nearest Resource ID, and nearest Bus ID, and should not be assumed to exactly denote the final bus-bar location."

Customer-connected energy storage projects:

- If the energy storage project fulfills a LCR procurement obligation, all of its capacity counts towards RA compliance (because such capacity has to be at least four-hours depth/duration), but none of this capacity is assumed to provide operational flexibility
- If an energy storage project does not help satisfy a LCR, none of its capacity is assumed to count towards RA compliance and none of this capacity is assumed provide operational flexibility, regardless of two, four, or six hour duration
- Energy storage projects for which no duration/depth information was made available, we assume 50% provide two-hour storage, 50% provide four-hour storage and 0% six-hour storage

It is reasonable to assume that cost-effectiveness requirements applicable to new storage capacity will lead to it being sited at the most optimal locations in order to allow these resources to help satisfy the local area reliability requirement. As CAISO staff identifies transmission constraints in the local areas in the current and future TPP technical studies they will also identify which transmission busses most optimally mitigate transmission constraints. Transmission, distribution and customer-side connected storage amounts providing capacity and flexibility identified in

Table 6 should be distributed among the transmission busses which most optimally mitigate transmission constraints within local reliability areas. As such, the identified transmission bus locations are potential development sites for storage and should help inform the procurement of storage resources necessary to meet the storage procurement target.

Table 7: Locational Information for PG&E's Energy Storage Resources

PG&E Energy Storage Resources						
Counterparty (Project Name)	**Point of Interconnection (POI)**	**Approximate Transmission Point of Delivery / Receipt**	**Approximate Nearest Resource ID (ResID)**	**Approximate Bus ID (BusID)**	**MW**	**Point of Connection**
Amber Kinetics (Energy Nuevo)	New 70 kV position in PG&E New Kearney Substation	New 70 kV position in PG&E New Kearney Substation	KERNEY_6_LD1	34480_KEARNEY _70.0_LD1	20	Transmission
Convergent (Henrietta)	Henrietta Distribution Substation (12kV)	Henrietta 70kV Substation	HENRTA_6_LD1	34540_HENRITTA_70.0_LD1	10	Distribution
Western Grid (Clarksville)	Clarksville 12kV Substation	Clarksville 115kV Substation	CLRKVL_1_LD1	32264_CLRKSVLE_115_LD1	3	Distribution
Hecate Energy (Molino)	Molino Transmission (69kV) Substation	Molino Transmission (69kV) Substation	MOLINO_6_LD1	31364_MOLINO _60.0_LD1	10	Transmission
NextEra Energy (Golden Hills)	Tesla Substation 115kV	Tesla Substation 115kV	TESLA_1_QF	33540_TESLA _115_GUM1	30	Transmission
Hecate Energy (Old Kearney)	Old Kearney 12kV Substation	PG&E New Kearney 70kV Substation	KERNEY_6_LD1	34480_KEARNEY _70.0_LD1	1	Distribution
Hecate Energy (Mendocino)	Mendocino 12kV Substation	Mendocino 60kV Substation	MENDO_6_LD2	31300_MENDOCNO_60.0_LD2	1	Distribution
Yerba Buena Pilot Battery Project	21kV Swift 2102 Feeder (into Swift 21kV Substation)	Swift 115kV Substation	SWIFT_1_NAS (not yet operational)	35622_SWIFT _115_GUNS	4	Distribution
Vaca Dixon Pilot Battery Project	Vaca Dixon 12 kV Substation	Vaca Dixon 115kV Substation	VACADX_1_NAS	31998_VACA-DIX_115_GUNS	2	Distribution

Table 8: Locational Information for SCE's Energy Storage Resources

SCE Energy Storage Resources

	Project	Storage MW	Product Type	Locational Information
LCR RFO 264 MW	Ice Bear	28.64	ES BTM PLS (customer-side)	N/A
LCR RFO 264 MW	AES	100	IFOM (distribution)	**Point of Interconnection:** 230kV bus at the Alamitos A-Bank Substation **Bus Name:** ALMITOSW **Bus Number:** 24007
LCR RFO 264 MW	Stem	85	ES BTM (customer-sde)	N/A
LCR RFO 264 MW	Hybrid Electric	50	ES BTM (customer-sde)	N/A

	Project	Storage MW	Product Type	Locational Information
ES RFO 16.3 MW	Stanton Energy Reliability Center	1.3	RA Only (distribution)	**Point of Interconnection:** Barre Substation **Bus Name:** BARRE **Bus Number:** 24201
ES RFO 16.3 MW	Western Grid	10	RA Only (distribution)	**Point of Interconnection:** Santa Clara Substation **Bus Name:** S.CLARA **Bus Number:** 24127
ES RFO 16.3 MW	Western Grid	5	RA Only (distribution)	

	Project	Grid Domain	MW in Plan	MW Actually Installed	A-Bank Substation	Bus Numbers at the 230kV used by TSP and CAISO
EXISTING SCE STORAGE APPROVED AS ELIGIBLE IN D.14-10-045	Tehachapi Storage	Distribution	8	8	Windhub 220/66	29407
EXISTING SCE STORAGE APPROVED AS ELIGIBLE IN D.14-10-045	Irvine Smart Grid-Community Energy Storage	Distribution	0.03	0.03	Santiago 220/66	24134
EXISTING SCE STORAGE APPROVED AS ELIGIBLE IN D.14-10-045	Irvine Smart Grid-Containerized Energy Storage	Distribution	2	2	Santiago 220/66	24134
EXISTING SCE STORAGE APPROVED AS ELIGIBLE IN D.14-10-045	Irvine Smart Grid-Residential ES Unit	Customer	0.06	0.06	Santiago 220/66	24134
EXISTING SCE STORAGE APPROVED AS ELIGIBLE IN D.14-10-045	Large Storage Test	Distribution	2	2	Barre 220/66	24016
EXISTING SCE STORAGE APPROVED AS ELIGIBLE IN D.14-10-045	Discovery Museum	Distribution	0.1	0.1	Villa Park 220/66	24154
EXISTING SCE STORAGE APPROVED AS ELIGIBLE IN D.14-10-045	Catalina Island	Distribution	1	1	N/A	N/A
EXISTING SCE STORAGE APPROVED AS ELIGIBLE IN D.14-10-045	V2G-LA AFB	Distribution	0.65	0.5	TBD	TBD
EXISTING SCE STORAGE APPROVED AS ELIGIBLE IN D.14-10-045	Self-Generation Incentive Program	Customer	10.9	9.66	TBD	TBD
EXISTING SCE STORAGE APPROVED AS ELIGIBLE IN D.14-10-045	Permanent Load Shifting	Customer	5.3	1.14	TBD	TBD
EXISTING SCE STORAGE APPROVED AS ELIGIBLE IN D.14-10-045	Home Batter Pilot	Customer	0.08	0	N/A	N/A
EXISTING SCE STORAGE APPROVED AS ELIGIBLE IN D.14-10-045	Distribution Energy Storage Integration 1	Distribution	2.4	2.4	Villa Park 220/66	24154

Table 9: Locational Information for SDG&E's Energy Storage Resources

Energy Division Data Request: Energy Storage Projects/Locational Information by Busbar			
Domain	**Project Name**	**Capacity**	**Bus ID Number**
Transmission	Lake Hodges Pumped Storage	40.00 MW	22603
Transmission	Hecate Bancroft	20.00 MW	22796
Domain	**Project Name**	**Capacity / kW**	**Bus Number at Transmission Substation to which Distribution Circuit Connects**
Distribution	Borrego Microgrid Yard- SES1	500	22084
Distribution	Pala Energy Storage Yard	500	22624
Distribution	Mission Valley- Skills Training Center	25	22496
Distribution	Clairemont	25	22136
Distribution	Poway	25	22668
Distribution	Borrego Springs CES	25	22084
Distribution	Borrego Springs CES	25	22084
Distribution	Borrego Springs CES	25	22084
Distribution	Century Park CES	50	22372
Distribution	Energy Inovation Center- Indoor	4.5	22136
Distribution	Energy Inovation Center- Outdoor	10	22136
Distribution	San Diego Zoo	100	22868
Distribution	UCSD MESOM	6	22864
Distribution	Suites at Paseo (SDSU Private Dormitories)	18	21008
Distribution	Del Lago Academy	100	22602
Distribution	Ortega Highway 1243 SES1	1000	22678
Distribution	Ortega Highway 1243 SES2	1000	22364
Distribution	Pala Energy Storage Yard SES	1000	22624
Distribution	Canyon Crest Academy	1000	22581
Distribution	Borrego Microgrid Yard- SES2	1000	22084
Distribution	Santa Ysabel Substation	6	22736
Distribution	Santa Ysabel Substation	30	22736
Domain	**Project Name**	**Capacity / MW**	**Nearest Bus ID Number**
Customer	SGIP/Non-SGIP Installed	6.66	TBD
Customer	SGIP/Non-SGIP In Progress	5.29	TBD
Customer	Permanent Load Shift Program	1.00	22864

All energy storage projects described here are 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.

Adjustments due to actual and expected storage projects

The 50 MW of storage that D.13-02-015 ordered SCE to procure, and the 25 MW[37] of storage that D.14-03-004 ordered SDG&E to procure, are assumed to count towards the D.13-10-040 storage procurement target; they should not be double counted.

The 40 MW Lake Hodges storage project located in the San Diego area counts as an existing resource assumption in the Scenario Tool. This project is assumed to satisfy a portion of SDG&E's share of the D.13-10-040 storage procurement target, and is reflected as doing so in Table 4.

4.2.5 Demand Response

Demand response (DR) programs whose impacts are not embedded in the California Energy Demand (CED) forecasts include several event-based, price-responsive and reliability programs. Within the LTPP planning horizon, these programs should achieve full integration into the CAISO wholesale market and therefore count as supply-side DR. Per Decision D.14-12-024, and reinforced by D.15-11-042, the Commission found that, as of January 1, 2018, DR programs must be fully bifurcated. DR programs must also be either fully integrated into the CAISO wholesale market (supply-side DR) or embedded in the CED forecasts (load-modifying DR), otherwise these programs will no longer have capacity value and thus will no longer receive resource adequacy credit.[38] As of December 2015, SCE has integrated most of its DR programs into the CAISO market, while PG&E and SDG&E have integrated smaller portions of their program portfolios. With the adoption of D.15-11-042, CPUC staff anticipates that the IOUs will integrate their DR programs into the CAISO market by the January 1, 2018 deadline.

The DR Load Impact Reports[39] filed with the CPUC on April 1, 2015, and other supply-side DR procurement[40] incremental to what is assumed in the Load Impact Reports, serve as the basis for the supply-side DR planning assumptions included herein. Transmission and distribution loss-avoidance effects shall continue to be accounted for when considering the load impacts that supply-side DR has on the system. The following table describes the total 2026 supply-side DR capacity assumptions, the details of which will be discussed in the remainder of this subsection.

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[38] That is, "supply-side" DR bids into the CAISO market and can receive resource adequacy credit, while "load-modifying" DR is embedded in the CED forecast and contributes by lowering the load forecast, thus lowering resource adequacy requirements.

[39] See Load Impact Report filings by each IOU on April 1, 2015, in R.13-09-011. PG&E also filed an amended report on June 12, 2015.

[40] Referring to procurement authorized by D.14-03-004 and DRAM, both described later in this subsection.

Table 10: Demand Response Supply-side Modeling Assumptions Summary

DR not embedded in IEPR demand forecast (values in MW):	PG&E	SCE	SDG&E	All IOUs	Assumed Market Participation	Assumed to respond within 30 minutes
IOU Load Impact Report DR in 2026 (a)						
BIP	246	611	1.5	859	RDRR	Yes
AP-I		66		66	RDRR	Yes
AC Cycling Res (b)	59	218	12.8	290	PDR	Yes
AC Cycling Non-Res	2	40	3.4	45	PDR	Yes
CBP	15	54	22.6	92	PDR	No
DBP	1	4	4.3	9	PDR	No
AMP (DRC)	101	93		194	PDR	No
Other procurement program DR						
SCE LCR RFO (c), post 2018		5		5	RDRR	Yes
DRAM (d) in 2016 only				40	PDR	No
DRAM in 2017 only				22	PDR[41]	No
DRAM in other years (e)				0		

Notes:

(a) Load Impact Report values are portfolio-adjusted August 2026 1-in-2 weather year condition ex-ante impacts at CAISO peak

(b) AC Cycling programs include Smart AC, SDP, and Summer Saver

(c) SCE LCR RFO refers to procurement authorized in D.14-03-004 with contract approved in D.15-11-041

(d) Demand Response Auction Mechanism is a 2-year pilot program of a maximum of one-year contracts

(e) For modeling purposes we assume capacity from existing programs described in the Load Impact Reports are a reasonable proxy for DR in 2026. It could turn out that by 2026, capacity from existing programs will be "retired" and "replaced" by significant growth in DRAM capacity.

In system resource planning studies, DR capacity based on the Load Impact Reports shall be counted using the portfolio-adjusted 1-in-2 weather year condition ex-ante forecast of

[41] Although the 2017 DRAM solicitation could include a mix of Reliability Demand Response Resource (RDRR) and Proxy Demand Resource (PDR), for modeling we will assume it is all PDR absent more definitive information.

monthly load impact at CAISO peak. This is consistent with the current DR capacity value calculation practice used in the CPUC's Resource Adequacy program. For the purpose of building load and resource tables in the Scenario Tool, DR capacity shall be counted using the portfolio-adjusted 1-in-2 weather year condition ex-ante forecast of August load impact at CAISO peak.

For planning models that require hourly impacts of DR, the aggregate DR capacity for a given hour is assumed to be the sum of the capacity of all DR programs that operate during that hour. The capacity of a DR program outside its operating hours is assumed zero. For DR programs described in the Load Impact Reports, CPUC staff assumes the average capacity during operating hours specified in Resource Adequacy accounting rules (1pm to 6pm) is representative of DR capacity for all of a given program's operating hours (which may include hours outside of 1pm to 6pm). For a DR program described by other procurement processes (e.g. SCE LCR RFO and DRAM in Table 10), the capacity procured is the hourly capacity to be modeled during that program's operating hours. CPUC staff intends to improve upon this coarse assumption of hourly DR capacity in future planning cycles. Developing temporally granular assumptions about future DR capacity at this time would embody a lot of uncertainty due to DR bifurcation and other program changes happening within the DR proceeding (R.13-09-011).

For planning models that require assumptions about how DR would be expected to dispatch, DR is assumed to be available at times of system stress, subject to program operating constraints but not limited to the operating hours specified in the Resource Adequacy accounting rules. Near-term studies, such as one or two years ahead, may reasonably model DR operating constraints based on the current tariffs associated with each program.[42] Longer-term studies (e.g. more than five years ahead) should model DR operating constraints based on full integration into the CAISO market, implying that DR participates in the CAISO market using either the Proxy Demand Resource (PDR) or Reliability Demand Response Resource (RDRR) CAISO market constructs.[43] In the interest of ensuring comparability between studies conducted by different parties, CPUC staff recommends that modeling the expected dispatch of DR participating as PDR or RDRR use the following conventions:

- DR assumed to participate as RDRR[44]
    - shall trigger when market prices are $950/MWh

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[42] To access IOU demand response tariffs please click on the following links.
PG&E: http://www.pge.com/en/mybusiness/save/energymanagement/index.page
SCE: https://www.sce.com/wps/portal/home/business/savings-incentives/demand-response/
SDG&E: http://www.sdge.com/save-money/demand-response/overview

[43] See http://www.caiso.com/participate/Pages/Load/Default.aspx

[44] Based on RDRR attributes described here:
http://www.caiso.com/Documents/ReliabilityDemandResponseResourceOverview.pdf

  - shall be dispatched for no more than 15 events and/or 48 hours total for June through September
  - shall be dispatched for no more than 15 events and/or 48 hours total for January through May and October through December
  - shall be consistent with other operating attributes specified by the RDRR construct, e.g. minimum load curtailment and run times
- DR assumed to participate as PDR [45]
  - shall trigger when market prices are $100/MWh
  - shall be dispatched for no more than 30 events and/or 120 hours total for the whole year
  - shall be consistent with other operating attributes specified by the PDR construct, e.g. minimum load curtailment and run times

Any party conducting Local Capacity Reliability Area planning studies must also make certain assumptions about available DR capacity under the grid conditions being studied. The CAISO conducts two types of planning studies related to Local Capacity Reliability Areas: Long-term Local Capacity Requirement (LCR) studies that study 10 years ahead and are conducted within the CAISO's annual Transmission Planning Process,[46] and Local Capacity Technical (LCT) Studies that study 1-5 years ahead and are used to inform the CPUC's Local Resource Adequacy requirements.[47] In these studies, the CAISO considers whether resources physically located within a Local Capacity Reliability Area can respond to a "first contingency".[48] In the most recent long-term LCR study, CAISO only counted DR resources physically located in Local Capacity Reliability Areas that can help re-position the system within 30 minutes after a first contingency.[49]

The Resource Adequacy Rulemaking R.14-10-010 is currently considering whether to change Local Resource Adequacy rules in order to create a requirement regarding how quickly DR resources that are physically located in Local Capacity Reliability Areas would need to respond in order to count as Local RA capacity. The CPUC's Resource Adequacy accounting rules currently have no requirement related to "first contingencies" or response

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[45] It is difficult to know in advance if these specific modeling conventions for RDRR and PDR will result in models the produce realistic dispatches of DR. Modelers may use some discretion in adjusting trigger price and event or hour caps in order to achieve realistic dispatches of DR. Any adjustments must be transparently documented and shared with all parties.

[46] http://www.caiso.com/Documents/RevisedDraft2015-2016TransmissionPlan.pdf

[47] http://www.caiso.com/informed/Pages/StakeholderProcesses/LocalCapacityRequirementsProcess.aspx

[48] The terms "first contingency" and "second contingency" were described in decision D.14-03-004, and the May 21, 2013 revised scoping ruling found here: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M065/K202/65202525.PDF

[49] The 30 minute requirement is based on meeting NERC Standard TOP-004-02

times for a resource to count as Local Resource Adequacy capacity. If a new methodology is approved by the CPUC in 2016 it should be used as the basis for counting resources that meet Local Capacity Requirements in future LTPP cycles.

Based on current program forecasts, CPUC staff estimate that in 2026, throughout the CAISO area, 1265 MW of DR would be available to count towards Local RA capacity and meet LCR needs – to the extent that the DR is physically located within Local Capacity Reliability Areas. CPUC staff developed the 1265 MW estimate by aggregating DR programs included in the Load Impact Reports that can deliver load reductions in 30 minutes, or less, from customer notification (which amounts to 1260 MW) with DR specifically procured to meet local reliability needs (5 MW). CPUC staff used the Load Impact Reports' August 2025 portfolio-adjusted 1-in-2 weather year condition[50] ex-ante forecast of load impact coincident with CAISO system peak, and assumed that the 2025 projection can be used as a proxy for 2026. DR specifically procured to meet local reliability needs is the 5 MW of DR that was procured pursuant to SCE's LCR RFO (approved, by D.15-11-041).[51] This 5 MW is assumed to be incremental to the 935 MW[52] of 30-minute-responsive DR in SCE's territory as calculated from the Load Impact Reports.

In addition to DR specified in the Load Impact Reports and DR procured through SCE**'s** LCR RFO**,** the CPUC has approved 40 MWs of DR contracts for system RA capacity procured through the pilot Demand Response Auction Mechanism (DRAM) for deliveries from June 1, 2016 through the end of 2016. A second auction will run in the spring of 2016 for deliveries starting January 1, 2017 through the end of 2017, for a mixture of system, local and flexible RA capacity. That auction has not yet occurred, so studies needing to make an assumption about DRAM capacity in 2017 should assume the minimum procurement target of 22 MW is procured and that the DRAM capacity will be used for system RA capacity. Note that at this time the pilot DRAM program is structured for contracts with lengths of up to one year, so long term planning assumptions can make no reasonable statement about expected long-term DRAM capacity. Therefore, CPUC staff continues to assume that the bulk of DR capacity expected to be present in the long term is best approximated by the DR projections in the Load Impact Reports. In the long term it may be

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[50] Note that although Local Capacity Requirement assessments study 1-in-10 year weather conditions, we assume DR capacity based on 1-in-2 year weather ex-ante impacts because this is currently the basis of the Qualifying Capacity value given to DR for both system and local Resource Adequacy compliance purposes.

[51] Note that the CAISO's recently proposed Business Practice Manual (BPM) change (https://bpmcm.caiso.com/Pages/ViewPRR.aspx?PRRID=854&IsDlg=0) calls into question whether the DR procured to meet local reliability needs through SCE's LCR RFO will be counted by the CAISO as eligible to meet local reliability needs. This is because the CAISO's proposed BPM change imposes a 20 minute response time on local DR resources as opposed to the 30 minute response time assumed in D.14-03-004 which authorized SCE's LCR RFO and D.15-11-041 which approved the DR resource.

[52] 935 MW = 611 MW of base interruptible + 66 MW agricultural pumping + 218 MW residential ac cycling + 40 MW non-residential ac cycling

possible that the capacity from existing DR programs described in the Load Impact Reports will be "retired" and "replaced" by significant growth in DRAM capacity.

For technical studies that require modeling DR capacity at individual transmission-level bus-bars, DR capacity should be allocated to bus-bar using the method defined in D.12-12-010, or to specific bus-bar locations provided by the IOUs. CPUC staff expects that the IOUs will provide updated bus-bar allocations to the CAISO for use in the 2016-17 TPP. The bus-bar locations also help determine which portion of aggregate 30-minute-responsive DR capacity within an IOU planning area is physically located within a Local Capacity Reliability Area.[53]

Given the uncertainty as to the DR amount that can be relied upon for mitigating first contingencies, the CAISO's 2014-15 and 2015-16 TPP Base Local Capacity Reliability Area studies examined two scenarios: one consistent with the 2012 LTPP Track 4 DR assumptions and one consistent with the 2014 LTPP DR assumptions of available 30-minute-responsive DR. CPUC staff expects that a similar two scenario approach will be used in the 2016-17 TPP; that is, the CAISO would study one scenario assuming a base level of DR capacity[54] to meet first contingencies, followed by a second scenario assuming full availability of the 30-minute-responsive DR described in Table 10 above – to the extent that DR is physically located in the Local Capacity Reliability Area being studied.

4.2.6 Over-supply and Over-generation

Testimony submitted in the 2014 LTPP Proceeding highlighted the potential for fairly significant amounts (400-900 GWh) of renewable over-supply by 2024 under a business-as-usual case, with the highest likelihood of a renewable over-supply conditions occurring in the March through May timeframe. These modeling efforts addressed the over-supply by curtailing renewable generation when prices reached the CAISO bid floor of-$300, or by allowing unlimited exports. CPUC staff has noted that economic curtailment has the potential to mitigate over-supply conditions that could otherwise lead to over-generation events. Economic curtailment clauses are a recent addition to standard IOU Power Purchase Agreements (PPAs) and allow the generation resource to be bid into the market, rather than to be self-scheduled; such clauses therefore enable that particular resource to be curtailed in the market when it is economically efficient to do so, as opposed to the previous, self-scheduled contractual model, where generated energy from renewables was accepted at any price point and could only be curtailed by an out of market action by the CAISO. Dispatching renewable curtailment at prices less negative than -$300 would more accurately reflect system operations.

[53] The CAISO noted that DR eligible for inclusion in the TPP must be allocated to bus-bars and must be a CAISO integrated resource, meaning that resource is mapped to specific PNodes.

[54] The CAISO has received updated information from SCE that increases the base level of DR capacity to meet first contingencies from what was assumed in previous TPP cycles. This is described in the CAISO's Draft 2016-2017 Transmission Planning Process Unified Planning Assumptions and Study Plan, p. 27 (http://www.caiso.com/Documents/Draft20162017StudyPlan.pdf.)

A CPUC staff analysis of economic curtailment provisions in IOU RPS contracts indicates that 80 GWh of pre-paid curtailment will be available in 2016. Moreover, if all RPS facilities with economic curtailment provisions are paid to curtail 100% of their output, they could collectively reduce 2070 GWh of generation in the months of March through May, during the hours of 8am-6pm, which is the timeframe when the potential for over-supply is forecast to be highest.

For the 2026 study year, the amount of pre-paid curtailment is forecasted to increase to 200 GWh, and total available economic curtailment in March through May of 2026 is forecasted to be 12,600 GWh.[55] Nonetheless, it should be noted that curtailing renewable resources runs contrary to the State's climate goals, and potentially increases the cost of RPS compliance by requiring the procurement of replacement generation during other times of the year.

As such, CPUC staff recommends that the LTPP planning assumptions be modified to assume that over-supply conditions are resolved by economic curtailment when production cost simulation modelling indicates it is economically efficient to do so. However, the Commission should utilize pre-paid curtailment as a tool of first choice, as it is an asset ratepayers have already paid for, before considering investment in additional resources to provide flexibility. The 80 GWh and 200 GWh of pre-paid curtailment available in 2016, and 2026, respectively, should be included as the minimum estimate (e.g. low-case) of available curtailment.
Economic and pre-paid curtailment should be integrated into CAISO system-wide production cost simulations with the following values:

[55] This is for illustrative purposes only. There is no expectation that any renewable resource would be curtailed 100% of the time.

Table 11: Pre-Paid Curtailment Amounts and Values by Year

Year	Quantity Available (GWh)	Value ($) / MWh
2016	80	-$10
2017	120	-$10
2018	142	-$10
2019	160	-$10
2020	194	-$10
2021	200	-$10
2022	200	-$11
2023	200	-$12
2024	200	-$13
2025	200	-$14
2026	200	-$15

Table 12: Economic Curtailment Amounts and Values by Year

Year	Quantity Available March 1st- May 31st, 8am- 6pm (GWh)[56]	Value ($) / MWh
2016	1990	-$25
2017	3031	-$25
2018	4072	-$25
2019	5113	-$25
2020	6155	-$25
2021	7195	-$25
2022	8236	-$25
2023	9279	-$25
2024	10318	-$25
2025	11359	-$25
2026	12400	-$25

4.2.7 RPS Portfolios

Overview

Plausible future portfolios of renewable resources for planning purposes are generated using the Renewable Portfolio Standard (RPS) Calculator, version 6.2. The RPS Calculator is a publicly vetted spreadsheet-based tool. It simulates how load serving entities (LSEs) in CAISO's balancing authority area could procure renewable resources in future years in order to meet their annual RPS compliance targets. Since the RPS Calculator is designed to provide input into CAISO's Transmission Planning Process (TPP), the renewable resources

[56] If additional curtailment beyond the amount of available economic curtailment for a given year in the March-May, 8am-6pm timeframe, is required, it should be valued consistent with the CAISO's current practice of -$300/MWh.

that may be needed for LSEs outside of CAISO to meet their own RPS targets are not represented in the RPS Calculator's output portfolio.

Background: 2016 LTPP

In the 2016 LTPP CPUC staff intends to use the RPS calculator to generate a set of portfolios that represent some plausible, and yet significantly different, outcomes. The RPS portfolios are not designed to test the range of RPS outcomes or to test the optimal RPS portfolio. Rather, they are selected to align with the LTPP scenarios and to facilitate the examination of the variables addressed by these scenarios. With this intent in mind, the six proposed RPS portfolios to be used in the 2016 LTPP studies are: a portfolio that is fully-deliverable; a portfolio that incorporates energy-only projects to reach the RPS target; a portfolio that will be used in the 2016-17 TPP studies; a portfolio that incorporates 3000 MW of wind resources from Wyoming; a portfolio that is fully-deliverable but that incorporates a Mid-AAEE trajectory (as appose to an SB 350 AAEE trajectory); and a portfolio which incorporates a reduced net export constraint of 5000 MW. These portfolios are further described in the "RPS Portfolio Selection" subsection, below.

The RPS Calculator can be used to generate a wide range of renewable resource portfolios depending on the input assumptions and the model settings that are utilized. The model settings include the RPS target being modeled and the timeframe for meeting such target; deliverability status of the projects in the supply curve from which the calculator can select; whether or not new projects that are located outside of California may be selected; and land-use restrictions within California. Input assumptions include the forecasted load data (e.g. Low, Mid or High); existing and expected resources; resource and transmission costs; and demand side management assumptions. As such, a portfolio that includes a high amount of AAEE (which effectively lowers demand), for instance, would result in a smaller RPS portfolio (in terms of MW or GWh of renewable resources) than a portfolio that combines a lower amount of AAEE. The latest version of the RPS calculator can be found on the "RPS calculator homepage" of the CPUC website here:
http://www.cpuc.ca.gov/RPS_Calculator/

The RPS Calculator's Portfolio Generation Process

The RPS Calculator creates renewable portfolios using an iterative process to select generic renewable resources and potential transmission upgrades needed to meet a particular RPS target in a specified future year. In order to generate an RPS portfolio, the RPS Calculator starts with base set of resources consisting of approved power purchase agreements (PPAs) and utility owned generation (UOG). The base set of renewable resources includes both existing resources currently in operation ("existing resources") and planned resources under contract that have not yet come online ("commercial resources").[57]

[57] The CAISO determined how much transmission capacity, in different zones throughout its balancing authority area, was available for use by new generation resources as of 1/13/2016. Those renewable resources that were expected to be online by that date based on contract information provided by LSEs are considered "existing

Footnote continued on next page

Next, a renewable net short (RNS) is calculated as the difference between approved generation (both existing and commercial) and the annual RPS target. In order to fill the RNS, a large set of potential renewable resources located throughout California and the WECC region ("generic" or "proxy" resources) are compared against each other using a calculation that includes several different cost and value elements. The cost and value elements in the RPS Calculator are similar to those in the Net Market Value (NMV) framework used in the "least cost, best fit" (LCBF) evaluation process required for procurement in the Commission's RPS proceeding. The NMV of each generic renewable resource is calculated as the sum of the following components: (a) resource cost; (b) transmission cost; (c) integration cost; (d) curtailment cost; (e) energy value; and (f) capacity value. A supply curve of renewable resources is developed by ranking each of the generic projects by their NMV.

Finally, the least-cost resources are selected from the renewable supply curve to fill the renewable net short for that year. The selected "generic" resources are added to the set of approved resources to create a new portfolio. The net short and resource selection process then repeats itself for each year of the simulation until the specified future year is reached.

Resource costs change over time due to technological innovation, financing, and tax policies. The resource composition of the existing portfolio also affects NMV of potential resources in the supply curve by changing the curtailment costs, capacity value, and energy value based on how much energy and capacity is already being provided by existing renewable resources throughout the year. As a result, the order of resources in the supply curve changes in each annual iteration of the procurement simulation based on the cumulative mix of resources that were selected the previous years. In this way, RPS Calculator selects not just the "least cost" resources, but those resources that offer the "best fit" given what is already present in the portfolio at the time the new resources are selected.

The RPS Calculator includes the ability to model the procurement of transmission upgrades in order to enable access to renewable resources in areas that have transmission constraints. Transmission upgrades are only triggered when the NMV of the bundle of resources that would be served by the upgrade, including the cost of the upgrade, is superior to any alternatives. The RPS Calculator uses one of two user-selectable options to further evaluate whether or not to trigger transmission upgrades. Under the "FCDS only"[58] option, the RPS Calculator triggers transmission upgrades such that all selected generic

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resources" in the RPS Calculator. Renewable resources that were expected to be online after that date are considered "commercial resources."

[58] "Full Capacity Deliverability Status"

resources have sufficient transmission capacity to be fully deliverable. Under the "FCDS & EO"[59] option, RPS Calculator triggers upgrades only when the net value of fully deliverable resources, accounting for the capacity value and transmission upgrade costs, is greater than the net value of energy only resources without transmission costs.

Inter-Agency Collaboration
The RPS Calculator relies, in part, on data developed by CEC and CAISO as inputs. Critical inputs generated by the CEC include load forecasts, energy efficiency forecasts, and BTM solar PV forecasts represented in the 2015 IEPR. The RPS Calculator also relies on CEC to provide information about renewable resources owned or contracted by POUs in CAISO territory. The RPS Calculator relies on input from CAISO to represent the available transmission capacity in different areas throughout the state, the limits on the amount of energy-only generation that may be added in different areas without triggering significant amounts of curtailment, and the costs and capacity of certain transmission upgrade projects.

The SuperCREZ[60] boundaries used by the RPS Calculator to divide generic resource potential throughout the state into areas that represent similar transmission constraints and upgrade costs were developed in consultation with CAISO.

RPS Portfolio Selection
Six portfolios have been specified to support the 2016 LTPP scenarios:

1) A portfolio reflecting a California energy future that could comply with SB 350 mandates while analyzing the impacts this mandate will have on reliability concerns, operational flexibility and transmission needs and over-supply conditions resulting from a greater amount of renewable penetration. This portfolio will be modeled as being "fully-deliverable"; that is, its resources will receive a capacity payment, in addition to an energy payment.

[59] "Energy Only"

[60] CREZ: "Competitive Renewable Energy Zones"

Table 13: RPS Calculator Assumptions for Default Portfolio

Category	Assumption
Test year	2026
RPS Percent	43.3% (on path to 50% by 2030)
RPS Deliverability	Fully Deliverable
Geography	WECC-wide
Load	2015 IEPR Mid
AAEE	2 x 2015 IEPR Mid-AAEE interpolated to 2026
Behind-the-meter PV	2015 IEPR Mid
DCPP	Retired in 2024/25
Net Exports Constraint	Mid Assumption (2000 MW)

2) An "Energy-Only" portfolio helps grid planners study the consequences of complying with SB 350 mandates while optimizing existing transmission infrastructure. The Energy-Only portfolio will also help grid planners to analyze the impacts this mandate will have on reliability concerns, operational flexibility and transmission needs and over-supply results. This portfolio incorporates existing renewable projects, but will fill the RNS by selecting generic projects on a LCBF basis from: a) renewable projects that receive an energy payment but that will not receive a capacity payment; and b) fully-deliverability generic projects, which receive both energy and capacity payments.

Table 14: RPS Calculator Assumptions for an Energy-Only Portfolio

Category	Assumption
Test year	2026
RPS Percent	43.3% (on path to 50% by 2030)
RPS Deliverability	Fully Deliverable & Energy Only
Geography	WECC-wide
Load	2015 IEPR Mid
AAEE	2 x 2015 IEPR Mid-AAEE interpolated to 2026
Behind-the-meter PV	2015 IEPR Mid
DCPP	Retired in 2024/25
Net Exports Constraint	Mid Assumption

3) A portfolio that gives added weight to Wyoming wind helps grid planners examine the impacts that a scenario that incorporates a lot of out-of-state resources may have on over-supply conditions and the resulting costs and benefits analysis relative to the portfolio used in the Default Scenario. This portfolio pre-selects 3,000 MW of Wyoming wind and adjusts the rest of the generic portfolio accordingly.

Table 15: RPS Calculator Assumptions for Out-Of-State Wind Portfolio

Category	Assumption
Test year	2026
RPS Percent	43.3% (on path to 50% by 2030)
RPS Deliverability	Fully Deliverable
Geography	WECC-Wide
Required	3000 MW Wyoming wind
Load	2015 IEPR Mid
AAEE	2 x 2015 IEPR Mid-AAEE interpolated to 2026
Behind-the-meter PV	2015 IEPR Mid
DCPP	Retired in 2024/25
Net Exports Constraint	Mid Assumption

4) A portfolio reflecting the increased RPS target pursuant to SB 350, but not reflecting the increased AAEE mandate per this same Senate Bill. This portfolio helps planners identify reliability concerns, operational flexibility and transmission needs and over-supply resulting from less aggressive AAEE forecasts and a higher RNS. This portfolio will be modeled as being "fully-deliverable"; that is, its resources will receive a capacity payment, in addition to an energy payment.

Table 16: RPS Calculator Assumptions With Mid-AAEE Forecast

Category	Assumption
Test year	2026
RPS Percent	43.3% (on path to 50% by 2030)
RPS Deliverability	Fully Deliverable
Geography	WECC-wide
Load	2015 IEPR Mid
AAEE	2015 IEPR AAEE Mid
Behind-the-meter PV	2015 IEPR Mid
DCPP	Retired in 2024/25
Net Exports Constraint	Mid Assumption

5) A portfolio reflecting that the Net Export constraint is increased to 5000 MW in order to reflect electric grid coordination over a larger geographic area which can facilitate the transfer of excess renewable energy.

Table 17: RPS Calculator Assumptions For Interregionalization

Category	Assumption
Test year	2026
RPS Percent	43.3% (on path to 50% by 2030)
RPS Deliverability	Fully Deliverable
Geography	WECC-wide
Load	2015 IEPR Mid
AAEE	2 x 2015 IEPR Mid-AAEE interpolated to 2026
Behind-the-meter PV	2015 IEPR Mid
DCPP	Retired in 2024/25
Net Exports Constraint	High Assumption (5000 MW)

6) A portfolio to be used in the 2016-17 TPP studies; CPUC Staff recommends reusing the "33% 2025 Mid-AAEE" RPS trajectory portfolio used in the 2015-16 TPP studies. It is a fully-deliverable portfolio which was developed using the old RPS calculator, version 5.0.

4.2.8 Technical Attributes of Solar PV projects

The physical configuration of solar PV projects influences the shape of their hourly generation profiles and has material impact on the outcome of resource planning studies that inform the LTPP. Two important physical attributes are the mounting-type and the DC-AC inverter loading ratio. Mounting-type includes the following:

- Fixed-tilt: stationary panels tilted, south-facing
- Tracking, 1-axis: panels track the sun on a single axis from East to West
- Tracking, 2-axis: panels track the sun on a dual axis (these projects are rare)[61]

The ratio of panel capacity to inverter capacity is the DC-AC inverter loading ratio and a higher ratio tends to flatten or clip the production profile of a PV project. Industry practice for PV installations has been to install a panel capacity larger than the inverter capacity to compensate for de-rate factors such as DC-AC conversions and losses and to maximize economic value. The aggregate assumptions for mounting-type and inverter loading ratio (ILR) for all future studies within the 2016 LTPP proceeding shall be consistent with the values in Table 18.

[61] Dual-axis tracking solar PV projects represent a tiny portion of tracking projects CAISO-wide, just 12 MW of capacity out of over 5,600 MW of IOU-contracted projects. For simplicity, the tables in this section treat dual-axis projects as if they were single-axis projects.

Table 18: Contracted Solar PV Capacity (MW) & Capacity-Weighted Average ILR, By Mounting-Type

	PG&E	SCE	SDG&E
Fixed-tilt capacity	2,043	876	395
Fixed-tilt ILR	1.26	1.24	1.29
Tracking capacity	1,406	3,334	938
Tracking ILR	1.28	1.31	1.29

Table 18 summarizes the IOU-contracted solar PV capacity (as of June 2015) for each of the three major IOUs and the capacity-weighted average inverter loading ratio separated by mounting-type.[62] "IOU-contracted" means the project has a CPUC-approved power purchase contract and it can be an existing online project or a project still under development. Because these projects have a CPUC-approved power purchase contract, their physical attributes are known and the projects are likely to be completed successfully.

For planning purposes, studies need to assume a mounting-type and inverter loading ratio for "generic" projects. The trends of mounting-type and inverter loading ratio in the most recent IOU-contracted projects can be used as a proxy for the likely physical attributes of "generic" projects. Table 19 below categorizes IOU-contracted projects by online year and identifies the amount of each mounting-type by capacity and percentage of total capacity.

[62] This data was aggregated from individual project data obtained from the CPUC Energy Division's RPS Contract Database (formerly known as Project Development Status Reports), June 2015 vintage, and data request responses from each IOU that provided physical attribute information for all IOU-contracted projects. Projects that were from these two data sources are either existing online projects or projects in development that are assumed to meet the criteria for "commercial" projects in the RPS Calculator. Some of these projects are in fact IOU-owned. The aggregated data does not identify market-sensitive information about individual solar PV projects.

Table 19: Contracted Solar PV Capacity (MW) Grouped By Mounting-Type & Online-Year

	any year	%	2014 or later	%	2015 or later	%
PG&E						
Fixed-tilt	2,043	59%	1,560	61%	176	17%
Tracking	1,406	41%	1,000	39%	831	83%
SCE						
Fixed-tilt	876	21%	836	21%	525	15%
Tracking	3,334	79%	3,215	79%	3,040	85%
SDG&E						
Fixed-tilt	395	30%	17	3%	17	7%
Tracking	938	70%	552	97%	225	93%
3 IOUs						
Fixed-tilt	3,315	37%	2,414	34%	718	15%
Tracking	5,678	63%	4,767	66%	4,097	85%

The newest projects (online in 2015 or later) tend to consist of tracking mounting-types. Based on this trend, "generic" projects selected by the RPS Calculator shall be assumed 15% fixed-tilt and 85% tracking.[63] There does not appear to be a clear difference in inverter loading ratios for newer vs. older projects. Therefore, "generic" projects shall be assumed to have inverter loading ratios similar to the capacity-weighted average of all IOU-contracted projects. Table 20 below summarizes the mounting-type and inverter loading ratio assumptions for "generic" (i.e. not yet contracted) projects. The percentage represents the share of all generic solar PV projects.

[63] Note that this subsection intends to override certain technical attributes of generic solar PV assumed by the RPS Calculator on the basis that trends in solar PV procurement are likely better indicators of the technical attributes of generic solar PV that would be realized in future procurement. This is partly because the RPS Calculator makes some simplifying assumptions about solar PV attributes in order to complete its calculations in a timely manner.

Table 20: Generic Solar PV Project Mounting-Type & ILR Assumptions

	PG&E	SCE	SDG&E
Fixed-tilt % share	15%	15%	15%
Fixed-tilt ILR	1.26	1.24	1.29
Tracking % share	85%	85%	85%
Tracking ILR	1.28	1.31	1.29

It is expected that technical modelers, especially those conducting production cost simulations, need to create 8760 hour annual energy profiles for bulk solar. Profile creation requires three key types of information: an 8760 hour solar irradiance profile varying by location, project installed capacity and location, and the technical attributes of each project. Solar irradiance data can be sourced from public datasets such as National Renewable Energy Laboratory's Solar Prospector[64] or Solar Integration National Dataset Toolkit.[65] Project installed capacity and location are provided by the RPS portfolio created by the RPS Calculator. Again, the technical attributes of bulk solar PV projects are specified by Table 18 and Table 20, above.

However, there is a potential for the annual energy outcome predicted by the RPS Calculator to be different from the annual energy profiles created by technical modelers and incorporating the technical attributes specified above. This is because the RPS Calculator uses simplified weather and technical attribute assumptions[66] to develop its RPS portfolio that meet a certain annual energy target and satisfy the desired RPS requirement (e.g. 50%). For consistency purposes the following method is adopted:

> Leave the installed capacity provided by the RPS portfolio unchanged. Create the annual energy profiles incorporating the technical attributes specified in this section and use those profiles as inputs to production cost simulations. This may result in annual energy outcomes somewhat different from what the RPS Calculator predicted (e.g. annual RPS energy percentage ended up at 48% or 52% instead of 50%).

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[64] http://maps.nrel.gov/prospector

[65] http://www.nrel.gov/electricity/transmission/sind_toolkit.html

[66] http://www.cpuc.ca.gov/RPS_Calculator/

Technical modelers are expected to document all details about how they create 8760 hour annual energy profiles for bulk solar, and how the profiles are used in technical studies (e.g. production cost simulations).

4.2.9 Nuclear Retirements

PG&E has not clearly stated if it will complete the relicensing process for Diablo Canyon Power Plant (DCPP); and if PG&E completes the relicensing process, it is not clear whether all licenses and permits will be approved. Additionally, it is not clear that PG&E will be willing to retrofit the plant's cooling technology if the State Water Resources Control Board's policy on cooling water intake structures requires a retrofit of DCPP as a condition for its continued operation.

As a default assumption in the 2016 LTPP, it is assumed that DCPP Unit 1 will be retired on November 2, 2024 and that Unit 2 will be retired on August 20, 2025.[67] An alternate assumption is that both DCPP units are relicensed and remain in operation through this LTPP forecast period.

4.2.10 Once-Through-Cooled Technology Retirements

The default assumption is that power plants using once-through cooling (OTC) technology retire according to the current State Water Resources Control Board (SWRCB) OTC compliance schedule, or sooner, per generation owners' latest implementation plans submitted to the SWRCB.

Moss Landing

The original compliance date for Moss Landing under the OTC compliance schedule was December 31, 2017. However, a settlement agreement signed by Dynegy (the owner of Moss Landing) and the SWRCB staff in October, 2014 extended this compliance date to December 31, 2020 for Units 1 and 2 and Units 6 and 7. This OTC amendment, per the settlement agreement, was approved by the SWRCB on April 7, 2015 and is now in effect. Nonetheless, the path to compliance for all of these units remains unclear. The plant's ownership stated its intent to install technology on Units 1 and 2 which will allow them to continue operating. Therefore, staff assumes that by December 31, 2020 Units 1 and 2 will be successfully retrofitted and that Units 6 and 7 will retire.

4.2.11 Renewable and Hydro Retirement Assumptions

Retirement assumptions are based on a facility's age as a proxy for determining a facility's remaining operational life. Operational history will not be considered in this planning cycle. 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

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[67] See "State Nuclear Profiles" page of the U.S. Energy Information Administration website http://www.eia.gov/nuclear/state/california/

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 a facility's age carry a wide range of uncertainty. As a default assumption, renewable and hydro resources are assumed to be on a "Low" level retirement schedule. If a facility announces a specific retirement date, that date will override these assumptions.

Table 21: Retirement Assumptions

Resource Type	Levels Of Assumed Retirement		
	"Low"	"Mid"	"High"
Solar/Wind	No retirement date	25 years	20 years
Other Renewable	No retirement date	40 years	25 years
Hydro	No retirement date	70 years	50 years

4.2.12 Other Retirement Assumptions

Retirement assumptions are also based on facility age as a proxy for determining a facility's operational life. Similarly to renewable and hydro retirement assumptions, the operational history of non-renewable/hydro facilities will not be considered in this planning cycle. A "Low" level of retirement assumes that "Other" resource types stay online unless there is an announced retirement date. A "Mid" level assumes a retirement schedule based on resource age of 40 years or more. A "High" level assumes a retirement schedule based on resource age of 25 years or more. Facilities which have an existing contract that runs beyond their assumed retirement age shall instead be assumed to operate until the expiration of the contract. Thus, a 38 year old facility in the "Mid" level that has a three year contract should be assumed to retire at 41 years once that contract expires. Commission staff will periodically request confidential procurement data from the utilities to screen for such facilities. "Other" includes all resources whose retirement assumptions are not explicitly described above – for example, peaker and cogeneration facilities. The default assumption for planning studies is a "Mid" level of retirement for "Other" resources.

"Cold shutdowns" or "Mothballed" Facilities

Generator owners that announce they will shut down their facilities, but which do not send notifications of retirement,[68] will be treated as follows: we will assume that, if economic conditions merit, these facilities could be made operational. As such, they will be considered existing resources, subject to the retirement rules.

Long Beach Peakers

From a technical and operational perspective, the Long Beach peaker plants can remain in operation at least through 2025 due to recent refurbishments. These peaker plants' economic lifespan, however, depends on whether this facility can successfully re-contract once its current contract expires in 2017. The planning assumptions in studies informing D.14-03-004 and the 2015-16 CAISO TPP assumed that the Long Beach Peakers would retire at the end of its current contract. In contrast, the retirement assumption specified in the Rulings on 2014 LTPP planning assumptions dated March 4, 2015 assumed that the Long Beach Peakers would remain online at least through 2025. The 2016 LTPP planning assumptions now assume that the Long Beach Peakers will retire by December 31, 2047, which is a date based on the year (2007) these peakers were refurbished and our "Mid" level 40 year lifespan assumption.

4.2.13 Imports and Exports

For the purposes of load and resource tables, i.e. the Scenario Tool, the default value for imports shall be based on the CAISO Available Import Capability for loads in its control area. This import capability is equal to the CAISO Maximum Imports minus Existing Transmission Contracts (ETCs) outside its control area, and is published on its website annually.[69] For 2016 the total import capability is calculated at 11,665MW.[70] In the Scenario Tool, the 11,665 MW value is used throughout the LTPP planning horizon. An alternative assumption is historical expected imports as calculated by the CEC.[71]

Technical planning studies require a more nuanced approach to accounting for imports. In the 2010 and 2012 LTPP studies the CAISO used a tool to calculate California statewide, and CAISO area maximum imports. That tool calculated import limits for each scenario being studied based on inertia changes in the Southern California Import Transmission

[68] As with what has happened when Calpine announced it would not operate the Sutter Energy Center Plant for the rest of 2016.

[69] 2016 Import Capability Assignment Process Steps 6 and 7; found here: http://www.caiso.com/FASTSearch2/Pages/allresults.aspx?k=import%20capability%20step%206

[70] For the source of the 11,665 MW of total import capability, look for "2016 Import Allocations" under "Import Allocation" here: "https://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx Click on "Step 6: 2016 Assigned and Unassigned RA Import Capability on Branch Groups".

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

(SCIT) area due to increased penetration of renewable resources and retirement of generation resources with inertia. The CAISO will update this tool and use it for the LTPP studies envisioned by this document.

For technical planning studies requiring information about infrastructure, resources, and loads outside of the CAISO area, the Transmission Expansion Policy Planning Committee (TEPPC) 2026 Common Case dataset should be used.

In regards to exports, the LTPP planning assumptions have historically been silent on the potential quantity of exports. The CAISO has, in the past, imposed a modeling constraint of "no net exports;" this reflects historical practice. As the system moves forward with regionalization efforts, however, further work is required to establish appropriate assumptions on the potential exports in different planning futures. In the 2016 LTPP, zero net exports will be deemed as the Low-case; 2000 MW of net exports will be considered the Mid-case; and 5000 MW of net exports will be incorporated as the High-case. The net export constraint assumed by modelers should be set at the Mid-case in all but the Interregional Coordination Scenario. For the Interregional Coordination Scenario the net export constraint should be set at the High-case.

4.2.14 Regional Generation Requirement and Frequency Response Constraints

In previous LTPP studies using production cost simulation models, a regional generation requirement constraint was imposed. This was modeled as a requirement for at least 25 percent of load to be met by generation from local resources within specific geographic areas in California. This constraint served as a crude proxy for ensuring sufficient local generation was online to supply both frequency response and the ability to respond to contingencies. Given recent infrastructure upgrades including new peaker resources in Southern California that enhance the ability to respond to contingencies, the 25 percent regional generation requirement constraint is removed. However, the need to supply sufficient frequency response must still be met, and this will be modeled by a new constraint in production cost simulation models that would ensure each balancing area can meet its obligations under the new NERC BAL-003-1 frequency response standard. According to the NERC BAL-003-1 standard and the CAISO's Frequency Response Stakeholder Process, the CAISO's current frequency response obligation is 258 MW/0.1 Hz, which can be interpreted to mean that the CAISO balancing area must have 752 MW of headroom at all times.

For consistency across different studies using production simulation models, modelers are directed to implement constraints to represent the CAISO balancing area's compliance with NERC BAL-003-1 as follows:

1. 50% of the headroom requirement (376 MW) is assumed to be met by hydro resources (excluding pumped hydro storage). However, no modeling constraint will be imposed on hydro. This is based on CAISO's operational experience that hydro can respond to under-frequency at any time without imposing explicit constraints on hydro operations.

2. 50% of the headroom requirement (remaining 376 MW) is assumed to be met by storage (excluding pumped hydro storage) and/or online combined cycle resources.
    a. Storage units assumed to provide flexibility services (as described in the storage assumptions section of this document) are allowed to meet the headroom requirement on a MW-for-MW basis, up to the available storage headroom.
    b. Combined cycle units can provide 0.08 MW toward the headroom requirement for each MW of online capacity, up to the available combined cycle unit head room.
3. Geothermal and nuclear typically operate at full load and are assumed to not contribute towards meeting the frequency response obligation.
4. The headroom requirement applies for all 8760 hours of the typical one-year production cost simulation model.

4.2.15 Existing Procurement Authorizations

Planning Assumptions Made With Pending Applications Data

Decision 15-11-041 approved the results of SCE's Local Capacity RFO (A.14-11-012) for the Western LA Basin pursuant to D.13-02-015 and D.14-03-004.

A Decision addressing SCE's Local Capacity Requirements RFO (A.14-11-016) for the Moorpark is expected to be issued this year; the projects that would help satisfy Moorpark's LCR are those with "location": Big Creek/Ventura and "Goleta" illustrated in Table 22.

SDG&E filled 500 MW of its 800 MW Track 4 LCR authorization via its power tolling agreement with Carlsbad Energy Center LLC. The complete set of planning assumptions for existing LCR procurement authorizations are specified in Table 22, below, and should be used in the 2016 LTPP studies. These assumptions should also be utilized to inform CAISO TPP studies.

Table 22: Procurement Assumptions With Approved and Pending Applications

Decision	Capacity (MW)	Assumed online	Location	Description
Approved: D.15-11-041	640	2020	Alamitos, Long Beach	Combined cycle gas turbine
Approved: D.15-11-041	644	2020	Huntington Beach	Combined cycle gas turbine
Approved: D.15-11-041	98	2020	Stanton	Peaker turbine
Approved: D.15-11-041	124	2020	W. LA Basin (Procured via SCE's LCR RFO)	Energy efficiency
Approved: D.15-11-041	5	2018	W. LA Basin (Procured via SCE's LCR RFO)	Demand response
Approved: D.15-11-041	38	2018	W. LA Basin (Procured via SCE's LCR RFO)	Distributed generation solar PV
Approved: D.15-11-041	135	2018	W. LA Basin (Procured via SCE's LCR RFO)	Battery storage – BTM
Approved: D.15-11-041	29	2020	W. LA Basin (Procured via SCE's LCR RFO)	Thermal storage – BTM PLS
Approved: D.15-11-041	100	2021	Long Beach (Procured via SCE's LCR RFO)	In-front-of-the-meter Battery storage – transmission-connected
Pending: A.14-11-016	6	2020	Big Creek/Ventura (Moorpark Sub-Area)	Energy efficiency
Pending: A.14-11-017	6	2018	Big Creek/Ventura (Moorpark Sub-Area)	Distributed generation solar PV
Pending: A.14-11-018	262	2020	Puente, Big Creek/Ventura (Moorpark Sub-Area)	Peaker gas turbine
Pending: A.14-11-019	0.5	2018	Goleta (Moorpark Sub-Area)	In-front-of-the-meter Battery storage transmission-connected
Approved: D.14-02-016	300	2016	Pio Pico site	Peaker gas turbine
Approved: D.15-11-041	500	2018	Encina site (Carlsbad)	Peaker gas turbine
Authorized / Pending	25	2019	San Diego	Battery storage – transmission-connected
Pending: A.6-03-014	18.5	2018	San Diego	Energy efficiency
Pending: A.6-03-014	20	2019	San Diego	Energy Storage

Note that the 264 MW (100 MW + 35 MW + 29 MW) of energy storage projects included in Table 22 also counts toward achievement of the storage procurement target in D.13-10-040 and are therefore counted in Table 8. These 264 MW are shown here is listed for completeness, but should not be modeled twice (double counted). Also note that the table above does not encompass the entirety of SDG&E's existing LCR procurement authorizations. Pursuant to D.15-05-051, SDG&E's residual procurement authority limited to preferred resources or energy storage, was revised to 300 MW. On March 30, 2016 SDG&E filed an Application (A.16-03-014), seeking approval of a 20 MW energy storage contract and 18.5 MW of EE projects. Assuming SDG&E's Application is approved, SDG&E's remaining preferred resource authorization is 261.5 MW.

Since the portfolio of resources necessary to meet SDG&E's authorization has not been determined, power flow studies should exclude the authorized but unprocured energy capacity. To the extent power flow studies identify an LCR need, the remaining 261.5 MW of authorized LCR procurement need should be considered first before authorizing new resources.

The energy efficiency, demand response, and distributed generation resource assumptions listed in Table 22 above represent incremental LCR procurement and are therefore assumed to be incremental to the other energy efficiency, demand response,[72] and distributed generation assumptions described earlier in this document.

<u>Interaction of LCR procurement and storage target</u>

Some of the storage projects included in the applications that would fill existing LCR procurement authorizations are assumed to satisfy the D.13-10-040 storage procurement target; these storage projects are noted in Table 22. Technical studies shall not double count these resources. Table 5 in the Energy Storage section (4.2.4) of this document does not include any adjustment to reflect how existing LCR procurement authorizations are assumed to satisfy the D.13-10-040 storage procurement target. The Scenario Tool illustrates the available capacity from assumed LCR procurement and reconciles how some of this LCR procurement satisfies a portion of the storage procurement target.

SCE's share of the D.13-10-040 storage procurement target for customer-side storage is 85 MW. However, the CPUC via D. 15-11-041 approved SCE contracts to procure 164 MW[73] of customer-side storage via its LCR procurement Application. This results, combined with other customer-side storage procurement, in SCE exceeding its customer-side storage target (per D.13-10-040) 95 MW. Table 6, Residual Energy Storage Procurement, has been adjusted to reflect the impact of LCR procurement, to date. Technical studies should therefore assume that SCE's share of the D.13-10-040 storage procurement target for customer-side storage is completely filled by its proposed LCR procurement. Note that all of the 164 MW of customer-side storage represented by SCE's LCR application should count as capacity in power flow studies because this storage is expected to be procured specifically to satisfy local capacity requirements – this supersedes the general assumption

[72] The "5 MW 2019 W. LA Basin Demand response" project included in Table 22 is the same 5 MW of incremental DR described in section 4.2.5 and should therefore not be double counted.

[73] These 164 MW include the Ice Bear (28.64 MW project) and two "Hybrid Electric, stern" (85 MW + 50 MW) projects. See Table 8.

described in the Energy Storage section that customer-side storage would not be able to provide capacity in power flow studies.

SCE's share of the D.13-10-040 storage procurement target for transmission-connected storage is 310 MW. However, SCE proposes to procure about 100 MW of transmission-connected storage in its LCR procurement applications. Therefore technical studies should assume that SCE's share of the D.13-10-040 storage procurement target for transmission-connected storage is partly filled by its proposed LCR procurement of 100 MW and the remaining share of the storage procurement target is 210 MW.

SDG&E's share of the D.13-10-040 storage procurement target for transmission-connected storage is 80 MW. After accounting for existing project Lake Hodges, the remaining share is 40 MW. Note that all of the 25 MW of transmission-connected storage represented by SDG&E's required LCR procurement, per D.14-03-004, should count as capacity in power flow studies because this storage is expected to be procured specifically to satisfy local capacity requirements.

4.3 Other Assumptions

4.3.1 The Second Planning Period

Planning studies which target years within the second planning period (2027-2036) will use simplified planning assumptions. Generally, these assumptions reflect extrapolation of the approaches of the first planning period.

- Net (managed) load growth will be extrapolated using the average, annual compound growth rate from the prior period. Only the net load will be extrapolated (i.e. the forecast load, after demand side adjustments such as AAEE), rather than extrapolating individual load or demand assumptions. The formula for calculating the growth rate
is…

$$GrowthRate = \left(\frac{NetLoad_{2026}}{NetLoad_{2016}} \right)^{\frac{1}{(2026-2016)}} - 1$$

…where Net Load is the gross load forecast minus AAEE. This annual growth rate is then applied to the 2026 Net Load to calculate the Net Load for 2027-2036.

- 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 renewable resources) will be calculated based on known and planned additions for all scenarios.
- Imports will be assumed to remain constant from the 2026 value through the second planning period.

- Dispatchable DR will be assumed to remain constant from the 2026 value through the second planning period.
- BTM PV is extrapolated beyond 2026 using a logarithmic trend line, as described in the "IncSmallPV Extrapolated" of the Scenario Tool.

4.3.2 Deliverability

Resources can be modeled as Energy-Only or Fully-Deliverable. The CAISO's TPP, for purposes of identifying needed policy-driven transmission additions, uses renewable resource portfolios provided by the CPUC that historically require full-deliverability. As an alternative to full deliverablitity and in order to better allow for analysis of options for providing additional generic capacity, in Energy-Only portfolios any additional resource will only be assumed to be Deliverable if it meets one of two criteria:

(1) Fits on the existing transmission and distribution system,[74] including minor upgrades,[75] or new transmission approved by both CAISO and CPUC, or

(2) It is a baseload or flexible resource.[76]

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 that were used in the 2014 LTPP proceeding shall be used for the 2016 LTPP proceeding.

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[74] For this purpose, "fits" refers to the simple transmission assumptions listed in the "CAISO_Tx_Inputs" tab of the RPS Calculator. Staff shall collaborate with the CAISO to update these transmission assumptions and apply them to the resource portfolios.

[75] Minor upgrades do not require a new right of way.

[76] 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.14-10-010. 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.

Natural Gas

The CEC's Natural Gas Reference Case as put forward in the 2015 IEPR shall be used as the base for calculating natural gas prices. 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

The GHG price forecast as put forward in the 2015 IEPR Natural Gas Market Assessment: Outlook report, to be published in December 2015 by the CEC, shall be used as the base for calculating GHG prices.

5 Planning Scenarios

5.1 2016 Planning Scenarios

The scenarios included herein are numbered in priority order. It is assumed that not all scenarios will be modeled due to resource constraints.

1. Default Scenario
2. Default Scenario – with Mid AAEE "sensitivity"
3. Deliverability (Energy-Only) Scenario
4. High BTM PV Scenario
5. TOU Rate Scenario
6. Interregional Coordination Scenario
7. Renewables Providing Operational Flexibility Scenario
8. Out-of-state Wind Scenario
9. Infrastructure Investment Scenario

Unlike previous LTPP cycles, Commission staff does not propose a trajectory scenario for the 2016 LTPP. The recent approval of SB 350 has made the trajectory of State policy clear on a broad basis, but additional development on specific modeling inputs is needed before a true trajectory scenario can be developed. Instead, staff recommends adopting a Default Scenario that can be used to test modeling inputs and provide information for the development of a trajectory scenario at a later date. The Default Scenario, however, should not be regarded as representing the Commission staff assessment of the most probable California energy future; rather, the Default Scenario should be considered as analogous to a "control group" of assumptions reflecting existing programmatic and energy policies that we will use to compare and contrast the differences between it and the other scenarios. These differences, which in most scenarios result from a change in just one variable, are described below.

The nine scenarios use one of six RPS portfolios and will test the overall impact that they have on GHG reduction and system reliability measures. The development and testing of the optimal RPS portfolio(s) will occur concurrently with the 2016 LTPP.

1. Default Scenario

What this scenario helps us study: The Default Scenario serves as a control scenario to which other scenarios will be compared and contrasted. The Default Scenario incorporates existing programmatic and energy policies, adjusted to preliminarily reflect the proposed changes mandated by SB 350. The actual program changes and/or implementations necessary to reflect the SB 350 mandates are not available at this time.

Why this scenario is worthwhile to study: Other scenarios can be compared and contrasted to the Default Scenario, shedding light on the impacts that certain variables – while holding all (or most other) things constant – have on the procurement and/or transmission planning study results.

How this scenario will be created: The Default Scenario incorporates key inputs and assumptions that will also be reflected in the other 2016 LTPP Scenarios. For example, four key demand and supply side inputs and assumptions in the Default Scenario are:

1) The 1-in-2 year peak weather Mid case 2015 IEPR demand forecast.

2) The doubling of the AAEE in the Mid-Baseline Mid-AAEE by 2030, interpolated to 2026.

3) A 43.3% RPS portfolio in 2026 (on path to 50% RPS by 2030).

4) Diablo Canyon Power Plant (DCPP) is offline in 2024/25.

Regarding the rest of the supply-side resource assumptions, this scenario assumes the default assumption for conventional resource additions, storage, dispatchable demand response programs and energy imports and exports. The Default Scenario further assumes a low level of renewable and hydro facility retirement and a Mid-level retirement for other resource types while accounting for existing procurement authorizations.

Table 23: Default Scenario Assumptions

Category	Assumption
Test year	2026
Load	2015 IEPR Mid
AAEE	2 x 2015 IEPR[77] AAEE Mid by 2030, interpolated to 2026
RPS Percent	43.3% (on path to 50% by 2030)
RPS Mix	WECC-wide
RPS Deliverability	Fully deliverable
DCPP	Retired in 2024/25
Local Frequency Constraints	NERC BAL-003-1 standard
Generation Fleet	CPUC NQC list
Gas Retirements	Retire at 40 years (unless under contract)
Gas Additions	CPUC/MUNI-approved contract
Behind-the-meter PV	2015 IEPR Mid
Demand Response	CPUC forecast
Combined Heat and Power	NQC + 2015 IEPR Mid
Net Export Constraint	Mid assumption (2000 MW)

Summary

Table 24 below summarizes how scenarios #2 - #9 differ from the Default Scenario by describing each scenario's distinct input variable and RPS portfolio.

Table 24: Potential Scenarios For Modeling In The 2016 LTPP

#	Scenario	Variable change	RPS portfolio
1	Default	Not Applicable	Default
2	Default sensitivity	AAEE	43.3% RPS, lower forecasted AAEE
3	Deliverability (Energy-Only)	Energy-Only RPS	43.3% RPS, energy-Only
4	High BTM PV	BTM PV load (Commission staff forecast)	Default
5	TOU Rate	Load curves	Default
6	Interregional Coordination	Net export, hurdle-rates, BA boundaries, frequency response constraint	Default
7	Renewables Providing Operational Flexibility	Modeling of renewables	Default
8	Out-of-state Wind	3000 MW of Wyoming wind	43.3% RPS, wind
9	Infrastructure Investment	Renewable portfolio	33% RPS

NOTE: "Commission staff forecast" indicates that staff would perform internal analysis in order to develop input variables.

[77] The preliminary SB 350 AAEE calculation will be based on the 2015 IEPR CED forecast; see section 4.1.4.

2. Default Scenario – AAEE sensitivity

What this scenario helps us study: This scenario will help planners study the results of a Default Scenario "sensitivity" that assumes a lower level of AAEE, and consequently, a higher load than that which is assumed in the Default Scenario.

Why this scenario is worthwhile to study: When compared to the Default Scenario, the results of this sensitivity scenario can provide valuable information regarding the impacts that lower levels of AAEE have on the need for flexible resources and GHG emissions. This is an important variable to study given the uncertainty of how much cost-effective AAEE can be realized beyond the amount adopted in the 2015 IEPR Mid-AAEE[78] forecast, and the uncertainty of how natural gas[79] and fuel-switching[80] technologies could impact AAEE amounts needed to comply with the SB 350 AAEE mandate.

How this scenario will be created: This Default Scenario "sensitivity" incorporates the same key inputs and assumptions as the Default Scenario with the exception of to AAEE assumption. Instead of "doubling of the AAEE in the Mid-Baseline Mid-AAEE by 2030, interpolated to 2026", it uses the adopted 2015 IEPR Mid-AAEE savings.

3. Deliverability (Energy-Only) Scenario

What this scenario helps us study: The Deliverability (Energy-Only) Scenario for the 2016 LTPP includes a 43.3% RPS portfolio by 2026 that consists of some renewable resources that are "energy-only,"[81] enabling us to explore the optimality of such portfolio relative to one that is fully-deliverable.

Why this scenario is worthwhile to study: This portfolio will enable the CPUC and the CAISO to better understand how the existing transmission infrastructure can be optimized while still reaching 50% RPS by 2030. Current practice in California maintains that new resources are made fully-deliverable, providing resource adequacy value to the system. The CAISO forecasts that there is sufficient transmission capacity on the system to reach the 33% RPS target while maintaining full deliverability on the system; however, it is

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[78] The Mid-AAEE savings assumption includes impacts from future updates to building codes, appliance standards and utility efficiency programs implemented after 2015.

[79] Calpine's comments to the draft A&S document made the point that "…the energy efficiency savings to meet the SB 350 goals could come from reduced natural gas usage. SB 350 allows required energy efficiency savings to be achieved through either reduced electricity or natural gas usage."

[80] SCE's comments to the draft A&S document argue that "AAEE may increase electricity demand through fuel-switching programs."

[81] The energy from energy-only resources flows to load centers only if sufficient capacity exists on a given transmission line.

unclear whether there is sufficient transmission capacity to accommodate 50% RPS by 2030 that is full-deliverable. Energy-only renewable resources could present a viable (and perhaps less expensive) alternative for reaching the State's GHG goals. The RPS calculator (in comparing energy-only vs. fully deliverable futures) shows that energy-only can affect the geographic distribution of generic renewable resources across the state and across the WECC (e.g., it shifts resources toward areas where existing transmission capacity is available). In other words, energy-only resources could impact the need for new flexible resources, system resources, and transmission capacity. When compared and contrasted to the Default Scenario, the Deliverability (Energy-Only) Scenario will also shed light on congestion issues that the grid operator might face in the event that an energy-only path is chosen to reach the 50% RPS target.

How this scenario will be created: New renewable resources (mainly those that are forecasted to satisfy the 33% to 43.3% tranche of this portfolio) will be modeled as energy-only resources that do not receive a resource adequacy payment. The RPS portfolio used in the Deliverability (Energy-Only) Scenario will be created by running the new RPS calculator version 6.2.

4. High BTM PV Scenario

What this scenario helps us study: In the High BTM PV Scenario the CPUC will consider the impacts that a higher amount of BTM PV – relative to what is included in the Mid-case IEPR demand forecast – have on costs, emissions, over-generation, and operational flexibility in CAISO's control area.[82]

Why this scenario is worthwhile to study: BTM PV resources have the potential to decrease the overall load served in the CAISO service territory, thereby reducing the need to procure electric resources, including utility-scale renewable resources. At the same time, increasing amounts of PV could escalate over-supply conditions and create (or exacerbate) operational flexibility issues.

How this scenario will be created: The High BTM PV Scenario will be created by: replacing the Default BTM PV assumption with the High BTM PV assumption. The default RPS portfolio is not changed.

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[82] Continued growth in PV adoption will likely reduce demand for utility-generated power at traditional peak hours to the point where the hour of peak utility demand is pushed back to later in the day. This means that future PV peak impacts could decline significantly as system performance drops in the later hours. This possibility has not been incorporated into the demand forecast through CED 2015, and such an adjustment to PV peak impacts could significantly affect future peak forecasts.

5. TOU Rate Scenario

What this scenario helps us study: The CPUC will utilize this scenario to consider the potential changes in the daily and seasonal load shapes resulting from significant changes in retail rates tariffs. Modeling these load shape changes helps planners assess the potential impacts that retail rate changes have on costs, emissions, over-generation, and ramping needs in CAISO's control area. Retail rate changes that will be modeled include defaulting residential customers to TOU rates, residential rate tier compaction,[83] and shifting TOU price periods.

Why this scenario is worthwhile to study: Policies that modify daily and seasonal load shapes and shift electric demand to time periods in which abundant renewable energy production exists have the potential to lower costs, emissions, and over-generation concerns for grid operations, with minimal infrastructure investment. Policies that shift electric demand may also interact with other grid integration measures, such as providing additional incentive to procure energy storage or to target energy efficiency measures at periods of the day when the cost of energy is high.

How this scenario will be created: The TOU Rate Scenario will be created by developing an 8760 hour load profile that is aligned with the 2015 IEPR peak and energy managed forecast. This load profile will be further adjusted to reflect the estimated impacts that the retail rate changes – specifically measures that default residential customers to TOU rates, redefined TOU price periods, and collapsed residential rate tiers – have on the load profile. A supplemental analysis included in the 2015 IEPR[84] (which is not part of the IEPR base case or managed forecast) presents six scenarios of estimated impacts from various retail rate changes that are incremental to the 2013 IEPR vintage of the California forecast. We propose using "Scenario 5" as described in the 2015 IEPR supplemental analysis, which includes TOU price period changes recommended by the CAISO and "conceptual" rates proposed by Commission staff designed to accommodate high renewable resource penetration. The "Scenario 5" load profile adjustment will need to be updated and aligned with the 2015 IEPR vintage of the California peak and energy forecast, and be further adjusted for AAEE and BTM PV impacts. The 8760 hour load profile will only be created for the target study year of 2026.

[83] Default TOU is scheduled for 2019. Tier compaction is ongoing, but should be completed in 2019.

[84] In a supplemental report, titled: "Joint Agency Staff Paper on Time-Of-Use Load Impacts".

6. Interregional Coordination Scenario

What this scenario helps us study: The CPUC will use this scenario to explore the impacts of improved interregional coordination, including full integration, between the CAISO and neighboring balancing authority areas.

Why this scenario is worthwhile to study: Electric grid coordination over a larger geographic area typically increases the diversity of both the load and the resources available to serve that load. Electric grid coordination can facilitate the economic and reliable transfer to external areas of excess low or zero marginal cost renewable energy that in some hours exceeds needs in the current CAISO footprint. If the ISO balancing authority area expands or even if coordination is greatly enhanced without full balancing authority expansion, this could change reliability and policy-related needs as well as economic opportunities – in ways that significantly impact CPUC-administered resource procurement programs. By proactively studying an appropriate informative scenario with expanded interregional coordination we can understand how implementation of key planning objectives may change (e.g., 50% RPS, low-carbon grid and various reliability needs). It would be especially timely to study enhanced coordination in the 2016 LTPP, as several utilities in the West have recently announced their intention to participate in the CAISO's Energy Imbalance Market (EIM), and PacifiCorp is considering full integration into an expanded ISO, with all that this entails. Furthermore, SB 350 expresses the Legislature's intent for the CAISO's scope to expand beyond California in order to promote the development of more efficient western electricity markets, to the extent it benefits California ratepayers.

How this scenario will be created: Modeling an expanded interregional coordination scenario involves decreasing or removing modeled non-physical constraints on energy and capacity exchanges between the current CAISO balancing area (BA) and neighboring balancing areas. It can imply combining existing balancing areas into fewer, larger balancing areas, which further implies optimized commitment and dispatch of resources to meet load over larger areas and optimized procurement of ancillary services over larger areas. The "expanded interregional coordination" scenario defined here is designed to be reflective of full integration between the current CAISO BA and the PacifiCorp BA, and continued expansion of the EIM to include several western BAs. This requires the following key adjustments to the model:

1. Change the model's BA boundaries for CAISO and PacifiCorp into one larger combined "CAISO plus PacifiCorp" BA, which implies several changes:

    a. Define the "net export constraint " to apply to the border of the one larger combined BA. Internal to the new combined BA, no such constraint applies anymore.

    b. Remove hurdle (wheeling) rates (charges) between the original CAISO and PacifiCorp BAs.

c. Ancillary services are procured from within the new combined BA.

d. Contingency (spin and non-spin) reserve requirements are recalculated based on the new combined BA coincident peak. This means overlaying the 8760 load profiles for the original CAISO and PacifiCorp BAs and finding the new coincident peak. The new total contingency reserve requirement may be lower given that the new combined coincident peak is expected to be lower than simply summing the CAISO coincident peak and the PacifiCorp coincident peak. In addition, the provision of contingency reserves can now be shared over a larger area. Thus, if there are oversupply conditions in California, then the bulk of contingency reserves could be procured from outside California (but of course still within the new combined BA).

e. Similarly, regulation and load-following reserve requirements are recalculated based on the composite load, wind, and solar profiles over the new combined BA. The provision of regulation and load-following reserves are likewise now shared over the new combined BA.

f. The frequency response constraint is recalculated to apply to the new combined BA, consistent with the methods and assumptions described in the CAISO's frequency response stakeholder process.[85] According to NERC BAL-003-1, each BA's frequency response obligation is based on its share of the total generation and load of the Western Interconnection. The new combined BA frequency response obligation is larger, but the pool of resources that can provide headroom to meet the obligation is also larger. We estimate that the frequency response headroom constraint for the new combined BA is 961 MW, which is the sum of the individual constraints for the original CAISO (752 MW), PacifiCorp East (147 MW), and PacifiCorp West (62 MW).

2. Change the "net export constraint" for the new combined CAISO plus PacifiCorp BA from the (default) mid assumption of 2000 MW to the high assumption of 5000 MW. This is intended to represent impact from an expanded EIM with participation from several western BAs, and further market coordination between the new combined CAISO plus PacifiCorp BA and other western BAs.

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[85] See details in: http://www.caiso.com/Documents/DraftFinalProposal_FrequencyResponse.pdf

3. The GHG adder modeled at flows coming into California will remain unchanged from other scenarios.

7. Renewables Providing Operational Flexibility Scenario

What this scenario helps us study: The CPUC will use this scenario to evaluate the system impacts of a flexible RPS fleet that can provide ramping up and/or down capacity (i.e. regulation, spinning reserves and load-following).

Why this scenario is worthwhile to study: Currently gas-fired electric generators are kept online so that the system operators can ramp these resources up or down in order to balance the system's electrical demand and supply. However, running gas-fired generators in order to balance the grid while reducing renewable output results in higher GHG emissions, which runs contrary to the State's RPS and GHG emission reduction targets. The Union of Concerned Scientists (UCS) recently found that reaching the 50% RPS target while utilizing zero or low GHG tools to provide operational flexibility (which include flexible operation of RPS generators) reduces the electric sector's GHGs by 20% relative to using existing "peaker" gas-fired resources for operational flexibility.[86] UCS's description of this more ideal electric system reliability paradigm could be realized by changing renewable procurement practices, modifying compensation to include other products besides kWh produced, requiring renewable generators to install control equipment, and by supporting/enabling the ability of renewable resources to participate in CAISO markets.

How this scenario will be created: In order to study the Renewables Providing Operational Flexibility Scenario, modeling conventions need to reflect the assumption that renewable generators may also ramp up and/or down as needed to maintain reliability.

8. Out-of-state Wind Scenario

What this scenario helps us study: The CPUC will use the Out-of-state Wind Scenario to study the impact that additional out-of-state wind resources have on CAISO's control area. This scenario will not model any of the changes included in the Interregional Coordination Scenario.

Why this scenario is worthwhile to study: This scenario will help shed light on the costs and benefits of accessing out-of-state wind to reach the State's RPS and GHG goals. Wind generated in Wyoming has a different production profile than wind resources in California. This scenario will help system planners examine if incorporating these resources reduce, or increase, over-supply conditions in California and understand the necessary adjustments needed for flexibility resources under such conditions. In addition, this

[86] Available online at: www.ucsusa.org/California50RPSanalysis

scenario will help system planners explore the amount (if any) of transmission infrastructure needed to deliver Wyoming wind to California.

How this scenario will be created: It will be modeled to reflect 3,000 MW of Southern Wyoming wind resources being deliverable to California. The RPS portfolio incorporated in this scenario will be produced by running the new RPS calculator version 6.2.

9. Infrastructure Investment Scenario

What this scenario helps us study: This scenario will be provided to the CAISO as the base-case to be used in the 2016-17 Transmission Planning Process (TPP) studies.[87]

Why this scenario is worthwhile to study: The renewable resources portfolio plays an integral role when modeling the electric system. The CAISO and the CPUC have a memorandum of understanding under which the CPUC provides a renewable resource portfolio for CAISO to analyze in the CAISO's annual TPP. The TPP analyzes the transmission system and determines the need for new transmission resources to ensure system reliability and meet policy goals (such as 50% RPS by 2030 target). This scenario updates critical operational variables of the transmission system but does not forecast an increase in renewable resources beyond the 33% goal used in previous trajectory scenarios.

CPUC and CAISO staff believe that it would be inappropriate to plan significant transmission expansion investments to access increased renewable resources before the CPUC has fully analyzed alterative renewable portfolios and selected a preferred course of action for infrastructure investment enhancements. If a fully-deliverable portfolio consisting of a RPS percentage greater than 33% is studied by the CAISO as part of its "base-case" TPP scenario, such a portfolio would likely result in a CAISO assessment indicating that new transmission capacity is needed to bring renewable energy, beyond the 33% RPS threshold, to market. We do not want to generate a renewable portfolio that might trigger new transmission investment, until more information is available.

Similarly, a new 33% RPS portfolio generated by the updated RPS calculator would be based upon increasing customer generation and declining IEPR load forecasts and

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[87] The CAISO authorizes new transmission infrastructure based on studies of the Base-Case scenario; via reply comments on the Draft Assumptions and Scenarios document CAISO stated: "The CAISO strongly supports staff's recommendation to use the 33% RPS portfolios for the 2016-17 transmission plan. Changing the portfolios used to plan the 33% RPS goals at this point will cause the CAISO to revisit already approved transmission solutions designed to meet the 33% RPS goal. This would in turn cause serious industry uncertainty regarding the state of already approved transmission solutions.

therefore could be based upon a lower RPS net short than the RPS portfolio used in the 2015-16 TPP. Such a portfolio might not support currently approved transmission projects that will be needed to reach 50% RPS goals. We do not want to generate a renewable portfolio which forces the CAISO to reexamine previously approved transmission investment decisions until more information is available.

Submitting the Infrastructure Investment Scenario for the CAISO to study as part of the 2016-17 TPP therefore ensures that the CAISO study results will reflect known transmission needs, not transmission needs based on speculative renewable portfolios. On a practical level, transmission capacity exists to interconnect additional renewable projects without major new transmission expansion. Nevertheless, a new RPS portfolio – even one that models a 33% RPS target – could still lead to a CAISO finding that new transmission capacity is necessary if such portfolio is sufficiently different than the 33% RPS portfolios previously studied.

How this scenario will be created: This scenario uses the same RPS portfolio that was supplied by Commission staff to the CAISO for the 2015-16 TPP, the "33% 2025 Mid AAEE" trajectory portfolio,[88] without updates. Therefore, the Infrastructure Investment Scenario has a different RPS percentage than the other scenarios. Other variables such as load and retirement dates (but not the retirement dates of renewable resources) will be updated to match the Default Scenario AAEE sensitivity.[89] As a result, the renewable GWh energy value contained in the Infrastructure Investment Scenario could exceed 33% of forecast demand.

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[88] See section "4.2.7 RPS Portfolios for the 2015-16 TPP" of "Attachment 2" (found here: PDF) from the "Assigned Commissioner's Ruling on updates to the Planning Assumptions and Scenarios for use in the 2014 Long-Term Procurement Plan and the California Independent System Operator's 2015-2016 Transmission Planning Process" (found here: PDF).

[89] As such, the managed load forecast will be based on the 2015 IEPR mid-demand, mid-AAEE. Diablo Canyon Power Plant (DCPP) should be modeled as being off-line by 2026 in the Infrastructure Investment Scenario. We assume that DCPP Unit 1 will be retired on November 2, 2024 and that Unit 2 will be retired on August 20, 2025.

Appendix A

	2015 IEPR AAEE Savings (GWh) Mid Base-Mid AAEE	"Doubling" Factor	SB 350 Projection (GWh)
2016	1,750	1	1,750
2017	3,581	1	3,581
2018	5,789	1.076923	6,234
2019	7,385	1.153846	8,521
2020	8,838	1.230769	10,877
2021	10,432	1.307692	13,642
2022	11,966	1.384615	16,568
2023	13,554	1.461538	19,809
2024	15,076	1.538462	23,194
2025	16,600	1.615385	26,815
2026	18,128	1.692308	30,678
2027	18,672	1.769231	33,034
2028	19,232	1.846154	35,505
2029	19,809	1.923077	38,094
2030	20,403	2	40,806

Note: *2015 IEPR* AAEE Projections extrapolated at 3 pecent per year from 2026 to 2030.

	2015 IEPR AAEE Savings (MW) Mid Base-Mid AAEE	"Doubling" Factor	SB 350 Projection (MW)
2016	472	1	472
2017	854	1	854
2018	1,332	1.076923	1,435
2019	1,702	1.153846	1,964
2020	2,064	1.230769	2,541
2021	2,451	1.307692	3,205
2022	2,821	1.384615	3,906
2023	3,209	1.461538	4,691
2024	3,597	1.538462	5,534
2025	3,991	1.615385	6,447
2026	4,390	1.692308	7,430
2027	4,522	1.769231	8,001
2028	4,658	1.846154	8,599
2029	4,797	1.923077	9,226
2030	4,941	2	9,883

Appendix B

PDG&E's Energy Storage Projects Locational Information by Busbar & Attributes (MW)

Counterparty (Project Name)	Point of Interconnection (POI)	Approximate Transmission Point of Delivery / Receipt	Approximate Nearest Resource ID (ResID)	Approximate Bus ID (BusID)	MW	Point of Connection	Total Installed Capacity	Amount providing RA capacity in power flow studies	Amount providing flexibility	Amount with 2 hours of storage	Amount with 4 hours of storage	Amount with 6 hours of storage
Amber Kinetics (Energy Nuevo)	New 70 kV position in PG&E New Kearney Substation	New 70 kV position in PG&E New Kearney Substation	KERNEY_6_LD1	34480_KEARNEY_70.0_LD1	20	**Transmission**	20	16	20	8	8	4
Convergent (Henrietta)	Henrietta Distribution Substation (12kV)	Henrietta 70kV Substation	HENRTA_6_LD1	34540_HENRITTA_70.0_LD1	10	**Distribution**	10	4	5	4	4	2
Western Grid (Clarksville)	Clarksville 12kV Substation	Clarksville 115kV Substation	CLRKVL_1_LD1	32264_CLRKSVLE_115_LD1	3	**Distribution**	3	1.2	1.5	1.2	1.2	0.6
Hecate Energy (Molino)	Molino Transmission (69kV) Substation	Molino Transmission (69kV) Substation	MOLINO_6_LD1	31364_MOLINO_60.0_LD1	10	**Transmission**	10	8	10	4	4	2
NextEra Energy (Golden Hills)	Tesla Substation 115kV	Tesla Substation 115kV	TESLA_1_QF	33540_TESLA_115_GUM1	30	**Transmission**	30	24	30	12	12	6
Hecate Energy (Old Kearney)	Old Kearney 12kV Substation	PG&E New Kearney 70kV Substation	KERNEY_6_LD1	34480_KEARNEY_70.0_LD1	1	**Distribution**	1	0.4	0.5	0.4	0.4	0.2
Hecate Energy (Mendocino)	Mendocino 12kV Substation	Mendocino 60kV Substation	MENDO_6_LD2	31300_MENDOCNO_60.0_LD2	1	**Distribution**	1	0.4	0.5	0.4	0.4	0.2
Yerba Buena Pilot Battery Project	21kV Swift 2102 Feeder (into Swift 21kV Substation)	Swift 115kV Substation	SWIFT_1_NAS (not yet operational)	35622_SWIFT_115_GUNS	4	**Distribution**	4	1.6	2	1.6	1.6	0.8
Vaca Dixon Pilot Battery Project	Vaca Dixon 12 kV Substation	Vaca Dixon 115kV Substation	VACADX_1_NAS	31998_VACA-DIX_115_GUNS	2	**Distribution**	2	0.8	1	0.8	0.8	0.4
						Totall	81	56.4	70.5	32.4	32.4	16.2

SCE's Energy Storage Projects Locational Information by Busbar & Attributes (MW)

	Project	Storage MW	Product Type	Locational Information			Total Installed Capacity	Amount providing RA capacity in power flow studies	Amount providing flexibility	Amount with 2 hours of storage	Amount with 4 hours of storage	Amount with 6 hours of storage
LCR RFO 264 MW	Ice Bear	28.64	ES BTM PLS (customer-side)	N/A			28.64	28.64	0	0	28.64	0
	AES	100	IFOM (distribution)	**Point of Interconnection:** 230kV bus at the Alamitos A-Bank Substation **Bus Name:** ALMITOSW **Bus Number:** 24007			100	100	50	0	100	0
	Stem	85	ES BTM (customer-sde)	N/A			85	85	0	0	85	0
	Hybrid Electric	50	ES BTM (customer-sde)	N/A			50	50	0	0	50	0
ES RFO 16.3 MW	**Project**	**Storage MW**	**Product Type**	**Locational Information**								
	Stanton Energy Reliability Center	1.3	RA Only (distribution)	**Point of Interconnection:** Barre Substation **Bus Name:** BARRE **Bus Number:** 24201			1.3	0.52	0.65	0.52	0.52	0.26
	Western Grid	10	RA Only (distribution)	**Point of Interconnection:** Santa Clara Substation **Bus Name:** S.CLARA **Bus Number:** 24127			10	4	5	4	4	2
		5	RA Only (distribution)				5	2	2.5	2	2	1
EXISTING SCE STORAGE APPROVED AS ELIGIBLE IN D.14-10-045	**Project**	**Grid Domain**	**MW in Plan**	**MW Actually Installed**	**A-Bank Substation**	**Bus Numbers at the 230kV used by TSP and CAISO**						
	Tehachapi Storage	Distribution	8	8	Windhub 220/66	29407	8	3.2	4	3.2	3.2	1.6
	Irvine Smart Grid-Community Energy Storage	Distribution	0.03	0.03	Santiago 220/66	24134	0.03	0.012	0.015	0.012	0.012	0.006
	Irvine Smart Grid-Containerized Energy Storage	Distribution	2	2	Santiago 220/66	24134	2	0.8	1	0.8	0.8	0.4
	Irvine Smart Grid-Residential ES Unit	Customer	0.06	0.06	Santiago 220/66	24134	0.06	0	0	0.03	0.03	0
	Large Storage Test	Distribution	2	2	Barre 220/66	24016	2	0.8	1	0.8	0.8	0.4
	Discovery Museum	Distribution	0.1	0.1	Villa Park 220/66	24154	0.1	0.04	0.05	0.04	0.04	0.02
	Catalina Island	Distribution	1	1	N/A	N/A	1	0.4	0.5	0.4	0.4	0.2
	V2G-LA AFB	Distribution	0.65	0.5	TBD	TBD	0.65	0.26	0.325	0.26	0.26	0.13
	Self-Generation Incentive Program	Customer	10.9	9.66	TBD	TBD	10.9	0	0	5.45	5.45	0
	Permanent Load Shifting	Customer	5.3	1.14	TBD	TBD	5.3	0	0	2.65	2.65	0
	Home Batter Pilot	Customer	0.08	0	N/A	N/A	0.08	0	0	0.04	0.04	0
	Distribution Energy Storage Integration 1	Distribution	2.4	2.4	Villa Park 220/66	24154	2.4	0.96	1.2	0.96	0.96	0.48
						Total	312.46	276.632	66.24	21.162	284.802	6.496

SDG&E's Energy Storage Projects Locational Information by Busbar & Attributes (MW)

Domain	Project Name	Capacity MW	Bus ID Number	Total Installed Capacity	Amount providing RA capacity in power flow studies	Amount providing flexibility	Amount with 2 hours of storage	Amount with 4 hours of storage	Amount with 6 hours of storage
Transmission	Lake Hodges Pumped Storage	40	22603	40.00	40.00	40.00	0.00	0.00	40.00
Transmission	Hecate Bancroft	20	22796	20.00	20.00	20.00	0.00	20.00	0.00
Domain	**Project Name**	**Capacity / MW**	**Bus Number at Transmission Substation to which Distribution Circuit Connects**						
Distribution	Borrego Microgrid Yard- SES1	0.5	22084	0.50	0.20	0.25	0.20	0.20	0.10
Distribution	Pala Energy Storage Yard	0.5	22624	0.50	0.20	0.25	0.20	0.20	0.10
Distribution	Mission Valley- Skills Training Center	0.025	22496	0.03	0.01	0.01	0.01	0.01	0.01
Distribution	Clairemont	0.025	22136	0.03	0.01	0.01	0.01	0.01	0.01
Distribution	Poway	0.025	22668	0.03	0.01	0.01	0.01	0.01	0.01
Distribution	Borrego Springs CES	0.025	22084	0.03	0.01	0.01	0.01	0.01	0.01
Distribution	Borrego Springs CES	0.025	22084	0.03	0.01	0.01	0.01	0.01	0.01
Distribution	Borrego Springs CES	0.025	22084	0.03	0.01	0.01	0.01	0.01	0.01
Distribution	Century Park CES	0.05	22372	0.05	0.02	0.03	0.02	0.02	0.01
Distribution	Energy Inovation Center- Indoor	0.0045	22136	0.00	0.00	0.00	0.00	0.00	0.00
Distribution	Energy Inovation Center- Outdoor	0.01	22136	0.01	0.00	0.01	0.00	0.00	0.00
Distribution	San Diego Zoo	0.1	22868	0.10	0.04	0.05	0.04	0.04	0.02
Distribution	UCSD MESOM	0.006	22864	0.01	0.00	0.00	0.00	0.00	0.00
Distribution	Suites at Paseo (SDSU Private Dormitories)	0.018	21008	0.02	0.01	0.01	0.01	0.01	0.00
Distribution	Del Lago Academy	0.1	22602	0.10	0.04	0.05	0.04	0.04	0.02
Distribution	Ortega Highway 1243 SES1	1	22678	1.00	0.40	0.50	0.40	0.40	0.20
Distribution	Ortega Highway 1243 SES2	1	22364	1.00	0.40	0.50	0.40	0.40	0.20
Distribution	Pala Energy Storage Yard SES	1	22624	1.00	0.40	0.50	0.40	0.40	0.20
Distribution	Canyon Crest Academy	1	22581	1.00	0.40	0.50	0.40	0.40	0.20
Distribution	Borrego Microgrid Yard- SES2	1	22084	1.00	0.40	0.50	0.40	0.40	0.20
Distribution	Santa Ysabel Substation	0.006	22736	0.01	0.00	0.00	0.00	0.00	0.00
Distribution	Santa Ysabel Substation	0.03	22736	0.03	0.01	0.02	0.01	0.01	0.01
Domain	**Project Name**	**Capacity / MW**	**Nearest Bus ID Number**						
Customer	SGIP/Non-SGIP Installed	6.66	TBD	6.66	0.00	0.00	3.33	3.33	0.00
Customer	SGIP/Non-SGIP In Progress	5.29	TBD	5.29	0.00	0.00	2.65	2.65	0.00
Customer	Permanent Load Shift Program	1	22864	1.00	0.00	0.00	0.50	0.50	0.00
			Total	79.42	62.59	63.24	9.06	29.06	41.29

(END OF APPENDICES)