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California Energy Commission

STAFF REPORT

Assessing Local Reliability in Southern California Using a Local Capacity Annual Assessment Tool: 2016 Update

California Energy Commission

Edmund G. Brown Jr., Governor

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California Energy Commission

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The spreadsheet modeling tool used in this analyses report is derived from tools developed by the California Public Utilities Commission, Energy Division. The report also uses, as inputs, the results of local capacity area studies using power flow modeling techniques conducted by the staff of the California Independent System Operator.

PREFACE

The California Energy Commission, California Public Utilities Commission, California Independent System Operator, and California Air Resources Board are working together to track energy resource development and electricity demand, and are identifying contingency mitigation options to assure electric system reliability in Southern California. The Energy Commission hosted workshops on this topic as part of the *2013 Integrated Energy Policy Report*, *2014 Integrated Energy Policy Report Update*, and the *2015 Integrated Energy Policy Report*. A workshop is scheduled as part of the *2016 Integrated Energy Policy Report Update*. The focus of this effort is local capacity requirements, or the amounts of in-area generation for 10 local areas in California needed to meet peak loads reliably. These requirements can be satisfied only by a restricted set of options compared to system reliability concerns. If needed, the mitigation measures developed in the plan will be available to guard against the adverse reliability impacts resulting from preferred energy resources, planned generation additions, or California Independent System Operator-approved transmission system upgrades not developing on schedule.

Decisions to implement specific mitigation measures will use appropriate decision-making processes of the implementing agency. Two types of mitigation measures are being developed: (1) short-term, once-through-cooling compliance date deferral for selected power plants, and (2) a conventional generator option. It is possible that other methods of addressing expected shortfalls in local capacity will be considered. The California Independent System Operator has also analyzed additional transmission alternatives if other resources fail to materialize.

Agency staff members are closely monitoring development of energy resources and expectations for future development that would be used to project whether local capacity requirements were likely to be satisfied, and if not, to recommend that one or more of the mitigation measures be triggered. Modeling tools that can provide annual projections are necessary to launch additional studies that could lead to a recommendation to trigger mitigation options in sufficient time to forestall contingencies from affecting reliability. This report describes the use of the Local Capacity Area Assessment Tool, a screening tool which focuses on the local capacity areas and selected subareas of Southern California impacted by the unplanned closure of the San Onofre Nuclear Generating Station and the closure of several large fossil-fueled power plants using *once-through cooling technology*.

This report updates a similar report published in 2015 as part of the *2015 Integrated Energy Policy Report* proceeding.

This report describes one facet of the overall contingency mitigation effort. Other reports and presentations elaborate the balance of the overall project.

ABSTRACT

This report describes analyses using a computer modeling tool developed by California Energy Commission staff that projects annual surpluses or deficits for energy resources versus local capacity requirements for several areas of Southern California. This tool uses as the baseline inputs the common body of assumptions developed for the California Public Utility Commission's 2014 Long-Term Procurement Plan rulemaking and the California Independent System Operator's *2015-16 Transmission Plan,* as well as the California Independent System Operator's power flow modeling study results estimating 2016, 2021, and 2025 local capacity requirements. This tool provides part of the analytic basis for determining that a future shortfall is likely and the patterns of such a shortfall, which are intended to be used by decision makers in deciding whether mitigation measures ought to be considered to resolve a contingency affecting local electric service reliability. Energy Commission staff reports on results for baseline assumptions, a sensitivity study examining the impact of uncertainty for key variables on an individual basis, and a scenario study examining the effects of multiple changes to the baseline assumptions. The analytic results provide a basis for recommendations for future efforts at the California Public Utilities Commission and the California Independent System Operator.

Keywords: Reliability, local capacity requirements, projections, electricity system requirements

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EXECUTIVE SUMMARY

This report provides the results of modeling to determine whether projected capacity meets or exceeds local capacity electricity requirements in several local capacity areas of Southern California. Each local capacity area is established by examining the set of transmission line segments between pairs of substations and calculating the maximum combined import capacity. Local capacity areas exist because the bulk transmission system cannot fully serve end-user load (electricity customer demand) under stressed conditions. Stressed conditions typically mean 1:10 peak load and two successive contingencies (generation and or transmission line outages). A 1:10 peak load represents a relatively extreme peak load that would only be encountered once in ten years. Local capacity requirements are an element of overall electric system reliability that describe the amount of generating capacity that must be available within the local area. Local capacity requirements are enforced through the resource adequacy process which requires that each load serving entity contract with its pro rata share of a local area's requirements using generation located in and available to the California Independent System Operator (California ISO) within the electrical boundaries of such local capacity areas.

A modeling tool developed by California Energy Commission staff projects electricity resource surplus or deficit on an annual basis from 2015 to 2025 for five local capacity areas or subareas within Southern California (Los Angeles Basin and San Diego). The 2016 update to this tool conforms projected baseline input assumptions to the package of inputs developed for the California Public Utility Commission's 2014 Long-Term Procurement Plan rulemaking and the California ISO's *2015-16 Transmission Plan,* as well as the California ISO's power flow modeling study results estimating 2016, 2020, 2021, and 2025 local capacity requirements. This tool is designed to assess whether surpluses or deficits can be expected for any of the intermediate years for which California ISO results are not available, or for sets of input assumptions not assessed by the power flow or stability studies.

Baseline results show projected deficits in two key areas--the West Los Angeles Basin subarea and the San Diego-Imperial Valley local capacity area. These deficits begin in 2021 and are linked directly to the retirement of once-through cooling generating facilities and insufficient development of power generation to replace the lost capacity. Sensitivity studies determine how much the results reduce or increase the surpluses or deficits found using alternatives for individual baseline assumptions. Similarly, scenarios defined as reasonable combinations of alternative packages of input assumptions can produce surpluses or deficits better or worse that those found using the baseline assumptions.

The baseline results suggest that the California ISO needs to continue conducting power flow and stability studies of credible contingencies of year 2021 for all of Southern

California. These sensitivity and scenario results suggest that close monitoring of many variables (peak demand load growth, expected savings from customer participation in energy efficiency programs, on-line date for new generation, retirement of cogeneration facilities, etc.) is necessary to assure that any projected deficits are detected sufficiently in advance that mitigation measures can be deployed in time to assure reliability. Given the reliance upon demand-side preferred variables, this monitoring recommendation falls particularly on the California Public Utilities Commission.

CHAPTER 1: Introduction

Southern California Reliability Project

Shortly following the June 2013 announcement by Southern California Edison Company (SCE) that it would retire the San Onofre Nuclear Generating Station (San Onofre) rather than repair the damaged steam generators, Governor Edmund Brown Jr. asked the energy agencies, utilities, and air districts to prepare a plan for the replacement of the power and energy that San Onofre had provided . The result of this effort was the *Preliminary Reliability Plan for Los Angeles Basin and San Diego*, prepared jointly by the technical staff of the involved agencies and utilities. The document was filed in the *2013 Integrated Energy Policy Report* docket and a presentation was made at a workshop hosted by the Energy Commission in September 2013.[1] Although the technical staff anticipated that the executive management of the energy agencies would finalize the document based on the draft and the comments made at the workshop, this did not occur. Nonetheless, certain implementation activities were initiated and an interagency team put in place that has met regularly since fall 2013. This team came to refer to its efforts as the Southern California Reliability Project (SCRP). The team members made presentations at an August 2014 workshop hosted by the Energy Commission as part of the *2014 Integrated Energy Policy Report Update* (*2014 IEPR Update*).[2] A similar workshop is planned as part of the *2016 Integrated Energy Policy Report Update* (*2016 IEPR Update*) proceeding.

Local Capacity Area Requirements

One of the key components of ensuring reliability in the Southern California region impacted by San Onofre is ensuring sufficient resources in the local capacity areas (LCA). Each LCA is established by examining the set of transmission line segments between pairs of substations and calculating the maximum combined import capacity. LCAs exist because the topology of the bulk transmission system does not allow peak load within such an area to be fully supported from resources anywhere in the balancing authority area because transmission lines would overload or voltage would be unstable. Each LCA must have sufficient generation located within the local area to meet peak load less the maximum import capacity of the transmission lines connected that area to the high-voltage transmission system . Local capacity requirements (LCR) describe the amount of generating capacity that must be available within the local area.

1 http://www.energy.ca.gov/2013_energypolicy/documents/#09092013.

2 http://www.energy.ca.gov/2014_energypolicy/documents/#08202014.

LCAs and the respective LCRs became a more visible element of electricity reliability planning when such local requirements became part of the resource adequacy program implemented by the California Public Utilities Commission (CPUC), California Independent System Operator (California ISO) and supported by the Energy Commission.[3]

Beginning in 2006, the California ISO began preparing annual assessments for each of the 10 local capacity areas for one- and five-year time horizons. One-year-ahead studies form the basis of local resource adequacy requirements that each load-serving entity must satisfy by contracting with enough generation to meet its share of total LCR requirement in the load pocket. The five-year-ahead study results were informational. The California ISO began conducting 10-year ahead LCR studies in support of the Assembly Bill 1318 (Pérez, Chapter 285, Statutes of 2009) project,[4] then for the CPUC in the 2012 Long-Term Procurement Planning (LTPP)/Track 4 proceeding. These studies have become a key element of the California ISO's annual transmission planning process.

LCR studies use power flow and stability modeling techniques to determine LCR results. These are highly labor-intensive and require great effort to set up and run. Accordingly, the number of specific cases with alternative sets of assumptions that the California ISO staff can assess is limited.

3 CPUC D.06-06-064, *Order Instituting Rulemaking to Consider Refinements to and Further Development of the Commission's Resource Adequacy Requirements Program*, June 29, 2006, http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/57644.PDF.

4 Assembly Bill 1318 requires the California Air Resources Board, in consultation with the Energy Commission, CPUC, California ISO, and the State Water Resources Control Board, to prepare a report for the Governor and Legislature that evaluates the electrical system reliability needs of the South Coast Air Basin.

CHAPTER 2: Method and Inputs

The Energy Commission developed a spreadsheet tool to support the overall contingency mitigation effort within the larger Southern California Reliability Project (SCRP). The tool is designed to project local capacity requirements versus available resources for each of five areas within Southern California annually to 2025. The tool provides an accounting of resources versus requirements, which might identify a year when resources no longer exceed requirements, for example, a shortfall is encountered. Standard planning assumptions developed by the CPUC and California ISO as part of LTPP or annual Transmission Planning Process (TPP) are used as the baseline assumptions. The effect of alternative assumptions, either as single-variable sensitivity studies or multivariable alternative scenarios, can be explored using the tool. This section will describe the method, baseline inputs, and two studies exercising the model. One study will examine the sensitivity of results to each variable and the other an assessment of alternative scenarios.

Method

The Energy Commission's local capacity annual assessment tool (LCAAT) is designed to supplement the in-depth power flow studies prepared annually by the California ISO. A key feature of this tool is embodied in the name—annual projections. The LCAAT closely replicates the results of local capacity requirements (LCR) that emerge from California ISO studies conducted for one- and five-year forward time horizons in its Local Capacity Technical Analysis (LCTA) studies, and the 10-year forward results prepared as part of recent cycles of the annual TPP. The LCAAT develops complementary results for the intervening years for which in-depth California ISO studies are not available. This year-by-year feature supports the purpose of the SCRP. The SCRP seeks to assure that electric service reliability is maintained in the areas of Southern California affected by the unplanned retirement of the nuclear units at San Onofre and the planned retirements of many fossil-fueled plants in response to the once-through cooling (OTC) policy adopted by the State Water Resources Control Board (SWRCB).[5] Although the OTC policy makes no explicit reference to retirements, the implementation plans submitted by the owners of the affected generating units have generally decided that making investments to satisfy the OTC policy is infeasible or not cost-effective. Retirement or retirement plus replacement are the general methods of complying with the OTC policy.[6] The LCAAT can also explore the consequences on

5 http://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/otc_2014.pdf.

6 http://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/powerplants/.

projected balance between resources versus requirements for a range of alternative assumptions different than those studied in-depth using power flow modeling techniques.[7] If expected resources fall short of the LCR, then policy makers need this information to determine whether and what contingency mitigation measures to trigger. The LCAAT is the analytic means to provide the look ahead needed to have adequate time remaining before the shortfall actually occurs to allow mitigation measures to be implemented effectively.

The LCAAT develops these annual projections for five areas within Southern California: the Los Angeles Basin (L.A. Basin), the West Los Angeles subarea within the L.A. Basin, the San Diego-Imperial Valley (SD-IV), the San Diego subarea, and the combined L.A. Basin/San Diego area most directly affected by the loss of San Onofre. Two areas are especially influenced by the loss of capacity from fossil-fueled OTC power plants. A capability to project future surpluses/deficits is critical to understanding how various mitigation measures might satisfy local capacity shortfalls.

LCAAT is implemented as an Excel® spreadsheet with multiple worksheets. As such, it is easy to operate, and input assumptions can be readily modified. This paper will document a sensitivity study that embodies 10 key variables for which there is substantial uncertainty about future assumptions. A separate scenario study assesses the consequence of selected packages of nonbaseline assumptions to identify how such alternative futures might affect the results for each region.

LCAAT is designed to project LCR in each of the five areas described, compute the total amount of resources expected to be available in such an area using standard capacity values for each resource, and thus determine in each future year whether there is a surplus or deficit of resources compared to requirements. Energy Commission uses net qualifying capacity values for each unit, which is the standard listing of the capacity of a power plant for use in satisfying resource adequacy requirements established by the CPUC and California ISO.[8]

Appendix A provides a generalized schematic of the information flows and associated sources within LCAAT.

Antecedents

The CPUC, California ISO, and Energy Commission have worked to develop tools conceptually similar to LCAAT to provide annual projections of LCA surpluses or

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7 Within some range around the baseline assumptions, the LCAAT results are probably equivalent to those using power flow modeling. Outside this range, then LCAAT's results may not be valid.

8 CPUC D.15-06-063, page 15, *Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2016 and 2017 Compliance Years*, June 25, 2015, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M152/K977/152977475.PDF.

deficits through time.[9] Such tools have long been considered an important means of evaluating the implications of OTC-based retirements of power plants throughout California. In particular, the fixed schedules established by the SWRCB for OTC facility retirements can raise questions about the timing of replacing these energy resources.

The CPUC has developed a "scenario tool" in the several LTPP rulemakings that was a useful starting point for the LCAAT since the CPUC staff had assembled an augmented net qualifying capacity list of resources for the entire California ISO balancing authority area and developed Excel logic that computed age-based retirements for several classes of resources.[10] This tool operates only on a California ISO balancing area authority level.

The CPUC 2014 LTPP Scenario Tool was modified by adding data attributing each generator to a local area or subarea, and the retirement logic was modified to perform these calculations for each of the areas within the LCAAT. Local capacity area and subarea requirements were added, and new display tables were constructed to understand results from the local capacity perspective. Numerous input assumptions, similar to those used in the CPUC's Scenario Tool, were added to enable accurate calculation of local capacity area results.

The 2016 version of the LCAAT is different from the 2015 version in that the baseline input assumptions were updated. The final year of analysis has been extended to 2025. The Eastern-Metro Subarea within the L.A. Basin has been dropped because California ISO studies no longer find this region to require separate treatment. In its place, results are prepared for the Eastern L.A. Basin subarea. The capability to examine the "peak shift" issue required developing a capability to both increase demand and decrease resource availability in a single sensitivity case.[11]

Inputs

The LCAAT draws upon most of the variables and specific assumptions developed by the CPUC in its biennial LTPP rulemaking.[12] Since these are also the basis for most of the variables important to power flow modeling by California ISO, there is close consistency between LCAAT inputs and those used in these planning processes.

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9 California ISO, *Overview of Load & Resource Scenario Study Tool for Use in Conjunction with Once-Through Cooling Reliability Assessments*, December 2010, for description of a prior tool developed, http://www.caiso.com/Documents/UpdatedLoadandResourceAnalysisScreeningToolDescription.pdf.

10 CPUC, Scenario Tool 2014, http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/ltpp_history.htm.

11 In addition to the mechanical implementation issues to implement "peak shift" as a sensitivity, extensive analysis of peak demand impacts and changes to expected resource performance was conducted offline.

12 Assigned Commissioner's Ruling, http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=88489746.

The LCAAT obtains LCR for each LCA from California ISO power flow studies released for one and five years forward as part of the LCTA reports submitted by the California ISO to the CPUC in the resource adequacy rulemaking, and for 10 years forward from the annual TPP report and appendices. These LCR values need to be adjusted in some instances to address changes in LCR stemming from new expectations of transmission upgrades affecting LCR, or other factors affecting local capacity requirements. Although, almost any change in input assumption within a power flow modeling study could result in a different LCR value, it is impractical for the California ISO to set up and run power flow studies for the many combinations of such assumptions. Thus, within a range, the LCAAT uses rules of thumb to adjust LCR values for the impact of alternative assumptions. For example, reductions from the base load forecast by energy efficiency, behind-the-meter (BTM) distributed generation (DG) (such as solar panels), and BTM energy storage are assumed to reduce local capacity requirements on a one-to-one basis. Each megawatt (MW) of net load reduction equals 1 MW of reduction in LCRs. Such adjustments are most prevalent for various demand-side preferred resources—energy efficiency, BTM energy storage, and BTM DG.[13] Comparable adjustments have also been assumed when new information about the scheduled in-service date for a transmission system upgrade differs from that assumed at the time of an LCR power flow study.

Projecting generating resources starts with a historical net qualifying capacity list developed jointly by the CPUC and California ISO each year as part of the resource adequacy proceeding. Existing resources are then tested in each future year to determine whether the resource has encountered the technology-specific lifetime, if it has retired or has been removed from the resource list for that year and future years. Should such a resource still be under contract to a load-serving entity, then retirement is delayed until the expiration date of the current contract.[14] Some resources—notably OTC fossil-fueled facilities—are retired when they meet the official OTC compliance date for that specific facility. New energy resources are added in two ways: (1) power plants large enough to be readily known and tracked through Energy Commission permitting or CPUC approval of a power purchase agreement; and (2) projections of renewable and DG resource portfolios as part of the biennial LTPP rulemaking.

Tracking large energy resources is more manageable because only those resources within a local capacity area are relevant for this model. Similarly, the subset of renewable and DG resources that are relevant to local capacity area studies is only a portion of all resources included within a Renewables Portfolio Standard (RPS) portfolio. Some challenges exist in translating the geolocational information about renewable and

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13 *Distributed generation* is power generated on the site of an end-use customer or by a connection to the distribution voltage system.

14 Such contract data are confidential, thus limiting public release of LCAAT and the detailed inputs.

DG projects projected by the CPUC staff's RPS calculator into local capacity areas and subareas.

For the numerous demand-side variables that affect load, efforts undertaken by the Energy Commission for additional achievable energy efficiency (AAEE) and by the CPUC for demand response for the California ISO's use in TPP power flow studies have been reused here.[15] SCE has provided LCA or specific substation for the demand-side preferred resources that it has proposed to the CPUC in A.14-11-007.[16] All the resources that San Diego Gas & Electric Company (SDG&E) will procure under CPUC D.14-03-040[17] are within the San Diego subarea, so no further geographic breakdown is needed.

Table 1 provides an overview of the source of key inputs that LCAAT uses to generate annual projections of surpluses or deficits of resources versus capacity requirements for each of the LCAs or subareas within LCAAT.

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15 *Demand response* provides wholesale and retail electricity customers with the ability to choose to respond to time-based prices and other incentives by reducing or shifting electricity use, particularly during peak demand periods, so that changes in customer demand become a viable option for addressing pricing, system operations and reliability, infrastructure planning, operation and deferral, and other issues. (See http://www.energy.ca.gov/glossary/glossary-d.html.)

16 CPUC, *Application of Southern California Edison Company (U338E) for Approval of its Energy Savings Assistance and California Alternate Rates for Energy Programs and Budgets for Program Years 2015-2017*, November 18, 2014, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M161/K951/161951995.PDF.

17 CPUC, *Application of San Diego Gas & Electric Company (U902M), Southern California Edison Company (U338E), Southern California Gas Company (U904G) and Pacific Gas and Electric Company (U39M) for Authority to Establish a Wildfire Expense Balancing Account to Record for Future Recovery Wildfire-Related Costs*, March 27, 2014, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M089/K383/89383322.PDF.

Table 1: Input Sources for LCAAT by Type

Type of Variable	Underlying Source	Projection Method
Demand		
Base Demand	CEC 2014 IEPR Update	1:10 peak forecast by local area/region
Planning Adjustments (AAEE, Demand Response, etc.)	CPUC 2014 LTPP Assumptions & Scenarios ACR	Reprocessing projections by substation to obtain local area values
Peak Increase From BTM PV Capacity	CEC staff analyses	Interim results using hourly modeling
Capacity Requirements		
Base LCR	ISO studies from 2016 and 2020 LCTA and 2015-16 TPP studies	Explicit for study years, interpolated for intervening years
Demand Adjustments	Various	Assumed to reduce LCR by user-defined parameter[18]
Transmission Adjustments	ISO project tracking, TPP studies, and private communication from ISO	Citations in various ISO studies and special requests by CEC staff to ISO transmission planning staff
Resources		
Base Year Projects	2015 Net Qualifying Capacity List	NA
Retirements		
General	2014 LTPP A&S ACR	Age-based retirement
OTC Adjustments	SWRCB	Compliance dates
Contract Terms	2016 contract database	Contract terms override age-based retirement
Additions		
Identifiable Projects	IOU PPAs	PPA details
Renewables/DG	RPS trajectory portfolio prepared for 2015-16 TPP	RPS calculator project output reprocessed to provide results by local capacity areas/eliminate duplicates
Surplus/(Deficit)	Calculated within LCAAT	Surplus/Deficit equal to resource total less adjusted LCR in each local area or subarea

Source: California Energy Commission staff

18 This parameter is set to a value of 1.0, but additional assessments are underway that may lead to a change.

Outputs

The LCAAT provides a requirements/resources summary table for each of the five areas. **Table 2** illustrates such results for the L.A. Basin for the baseline set of assumptions. Four "blocks" of related types of data exist within the summary table:

The top rows provide the baseline peak demand forecast and related adjustments by various demand-side measures. A base load forecast adjustment reflects nonspecific changes to the adopted Energy Commission demand forecast. AAEE is the principal energy efficiency assumption complementing the base Energy Commission peak load forecast. Demand-side power purchase agreement (PPA) results from SCE and SDG&E request for offer (RFO) under CPUC D.14-03-004 further reduce demand.

Gross LCRs show the gross amounts of capacity required in the area prior to the impacts of demand-side or transmission system upgrades, followed by the net LCRs.

A large block of data provides a resource summary by type of supply-side resource. Most demand response is included as a resource type rather than as a load modifier consistent with CPUC and California ISO practice. Storage additions in front of the meter can be taken from investor-owned utility (IOU) RFO results or for sensitivity/scenario purposes from the CPUC storage decision.

The final block is the resource versus requirement projection of surpluses or deficits. The surplus/deficit is calculated as total resource base less adjusted LCR base.

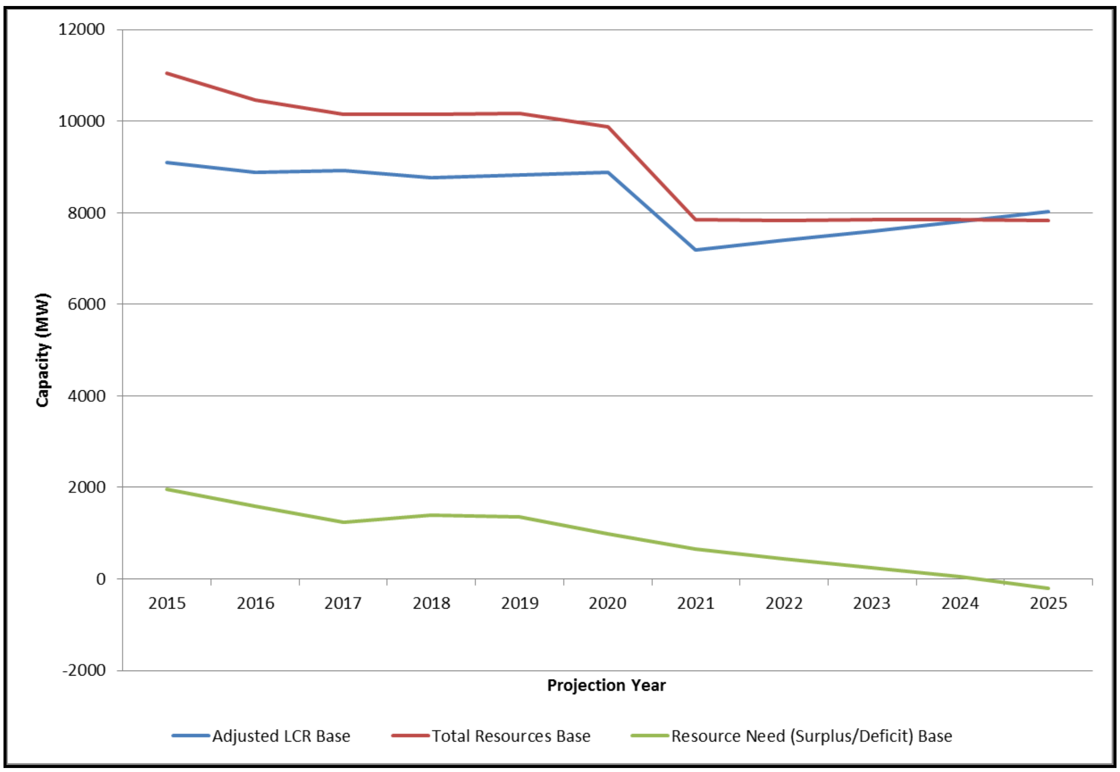
Various graphical presentations can be developed to show how principal variables change through time. **Figure 1** highlights a few key variables showing total resource base, adjusted LCR requirements and resource need (surplus/deficit). **Figure 1** should be read such that whenever total resource base is below adjusted LCR requirements, then a shortfall (deficit) would exist. As shown in **Table 2**, although there is a considerable loss of OTC generating resources between the summers of 2020 and 2021, the L.A. Basin still has a surplus that gradually disappears by the last projection year of 2025.

Table 2: Illustrative Output for Each Area—Example for L.A. Basin Baseline Case

	Variables (Summer Peak MW)	Source	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
LA Basin													
	Base Load Forecast	2014 IEPR Up	21206	21418	21681	21956	22229	22517	22781	23031	23273	23493	23717
less	Load Forecast Adjustment (positive is a decrease)		0	0	0	0	0	0	0	0	0	0	0
less	AAEE	2014 IEPR Up	123	247	372	460	559	649	737	828	936	1044	1164
less	Preferred EE	SCE RFO	0	5	24	99	120	128	130	120	109	98	88
less	Preferred BTM Energy Storage	SCE RFO	0	0	25	163	169	172	170	172	172	172	172
less	Preferred BTM DG	SCE RFO	0	0	11	40	40	40	40	40	40	40	40
=	Managed Load Forecast		21083	21166	21250	21194	21341	21527	21703	21871	22017	22139	22252
	Gross Local Capacity Requirements		9460	9374	9985	10258	10203	10378	9062	9352	9658	9964	10283
less	T-system Upgrade Impacts		(240)	(240)	(640)	(740)	(500)	(500)	(800)	(800)	(800)	(800)	(800)
less	LCR Change from Demand Adjustments		(123)	(252)	(431)	(762)	(888)	(989)	(1078)	(1160)	(1256)	(1354)	(1464)
=	Adjusted LCR Base		9097	8882	8914	8756	8814	8889	7184	7392	7601	7811	8019
	OTC Non Nuclear	ScenTool	4153	3818	3818	3818	3818	2238	0	0	0	0	0
plus	OTC Nuclear	ScenTool	0	0	0	0	0	0	0	0	0	0	0
plus	Hydro	ScenTool	307	307	308	308	308	308	308	308	308	308	308
plus	Solar	ScenTool	22	22	22	22	22	22	22	22	22	22	22
plus	Wind	ScenTool	59	59	59	59	59	59	59	59	57	57	55
plus	Geothermal	ScenTool	0	0	0	0	0	0	0	0	0	0	0
plus	Biomass	ScenTool	97	97	97	97	97	97	97	97	97	97	97
plus	Cogeneration	ScenTool	712	712	712	712	712	712	712	683	683	683	652
plus	Pump	ScenTool	0	0	0	0	0	0	0	0	0	0	0
plus	Non OTC Peaker	ScenTool	1199	1154	1154	1154	1154	1154	1154	1154	1154	1154	1154
plus	Non OTC Thermal	ScenTool	4312	3992	3672	3672	3672	3672	3672	3672	3672	3672	3672
plus	Various and Unknown	ScenTool	33	33	33	33	33	33	33	33	33	33	33
plus	Incr. Peaker Additions	SCE RFO	0	0	0	0	0	0	98	98	98	98	98
plus	Incr. Thermal Additions	SCE RFO	0	0	0	0	0	1280	1280	1280	1280	1280	1280
plus	Incr. RPS Calc - Renew	14/15 Port	0	0	0	0	0	0	0	0	0	0	0
plus	Incr. RPS Calc - DG	14/15 Port	0	103	103	108	110	114	123	144	170	170	170
plus	Storage Additions	SCE RFO	0	0	0	0	0	0	100	100	100	100	100
plus	DR Program/Preferred DRCapability		164	167	169	177	180	182	185	182	182	182	182
=	Total Resources Base		11056	10463	10145	10158	10163	9870	7841	7830	7855	7855	7822
=	Resource Need (Surplus/Deficit) Base		1959	1580	1232	1401	1349	981	656	438	253	44	(197)

Source: California Energy Commission staff

Figure 1: Key Variables—Example for L.A. Basin Baseline



Source: California Energy Commission staff

CHAPTER 3: Baseline Results

The baseline results using the LCAAT stem from a package of input assumptions described generically in **Table 1**. Detailed results using the format of **Table 2** are provided in Appendix B for each of the six areas.

Table 3 provides a compact summary of the baseline results using the numeric resource surplus/deficit resulting from the comparison of resources versus requirements through time for each of the six areas

Table 3: Baseline Resource Surplus/Deficit by Area (MW)

AREA		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
LA Basin/San Diego Subarea		1813	1563	1373	1247	1286	1005	531	294	102	(132)	(400)
LA Basin		1959	1580	1232	1401	1349	981	656	438	253	44	(197)
West LA Basin Only (subset of LA Basin)		2365	2201	2128	2252	2154	1742	(411)	(532)	(617)	(727)	(836)
San Diego/Imperial Valley Area		603	1775	1933	1638	1730	1816	(73)	(92)	(100)	(124)	(151)
San Diego Sub-Area		(147)	(18)	141	(154)	(62)	24	(126)	(144)	(152)	(176)	(203)
Eastern LA Sub-Area (a subarea within LA Basin)		1908	1584	1380	1496	1611	1727	1068	970	870	771	639

Source: California Energy Commission staff

As noted, the negative values in 2025 closely match those provided by the California ISO in its 2015-16 TPP study results.[19]

The appearance of LCR shortfalls in 2021 is expected as December 31, 2020, is the date that major capacity reduction occurs when the remaining L.A. Basin OTC capacity must comply with SWRCB OTC policy. Of the original list, a considerable number of affected facilities have already complied by retiring.[20] The owner/operators of OTC power plants almost universally state that they intend to shut down existing facilities rather than attempt to retrofit the water intake structures for these power plants.[21] This date has been known since May 2010, when SWRCB adopted its OTC policy. The resources that have been authorized by the CPUC barely cover the minimum required, and when these are placed on the same accounting basis as resource adequacy, a shortfall occurs in the combined L.A. Basin/San Diego subarea affected by the San Onofre outage. This deficit grows slowly each year and reaches 400 MW by summer 2025.

19 California ISO, *2014-15 Board Approved Transmission Plan*, p. 147.

20 http://www.energy.ca.gov/renewables/tracking_progress/documents/once_through_cooling.pdf.

21 SWRCB, OTC, "Power Plants That Are Affected for Facility-Specific Letters," http://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/powerplants/.

A deficit appears only in 2025 in the L.A. Basin load pocket.[22] One of the key drivers contributing to the absence of a deficit in most years is the ramp-up in AAEE. The low-mid AAEE in the baseline assumptions ramps up more than 400 MW between 2021 and 2025. For the West Los Angeles subarea of the L.A. Basin (the area with the greatest concentration of old OTC facilities), the deficit appears in 2021 and steadily grows out to 2025. The Eastern L.A. Basin subarea has a substantial surplus in early years but suffers age-based retirements from old steam boiler plants like Etiwanda.[23]

Farther south, the SD-IV load pocket has a substantial surplus until 2021, when the LCR value increases dramatically. California ISO studies from the 2015-16 TPP continue to show linkage between L.A. Basin and San Diego as in past TPP cycles. The California ISO has identified thermal overloads that occur between Western L.A. and San Diego as power flows south once the 500 kilovolt Mesa Loop-In project brings greater amounts of power from the north and east into (and through) the coastal portions of SCE's transmission system. These regional studies suggest that more capacity in the entire SD-IV area must be available to the California ISO under the contingencies that have been assessed. Conversely, the San Diego subarea (the actual retail service area of SDG&E) has small surpluses or deficits until 2020, when deficits gradually start steady growth.

The need to solve West Los Angeles deficits with resources located in West Los Angeles subarea—only a portion of the overall combined area—may suggest that there is no ideal resource addition that minimizes the surplus for all areas. Additional resources may be needed in West L.A. and San Diego.

The baseline results for the combined L.A. Basin-San Diego subarea closely match the California ISO's studies for 2021 and 2025. In 2014-15 TPP studies for 2024, the California ISO reported a small deficit in 2024 that could be accommodated by "repurposing" demand response capability that it did not count in its baseline assumptions.[24] The California ISO uses repurposing to mean that the objectives and mechanisms of demand response programs are revised to match its requirements. For example, to shorten the time by which customer load reductions have been achieved.

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22 In calculating surplus or deficit, the California ISO carries over a subarea deficit to the larger area, so in its study, L.A. Basin shows a deficit in 2021 because the West L.A. subarea deficit is carried over to L.A. Basin. In LCAAT accounting, subarea deficits are not carried over to the local area, so the LCAAT shows a surplus in 2021 for the L.A. Basin even though it also shows a deficit in the West L.A. subarea. The LCAAT results for L.A. Basin show that a surplus of resources in the Eastern L.A. subarea is more than enough to overcome the deficit in West L.A. subarea, even though they are located poorly for solving problems in West L.A. subarea. Reviewing results for both load pocket and subareas is necessary to understand where resources should be located to eliminate projected deficits, whether using the California ISO reporting convention or the Energy Commission reporting convention.

23 Most steam boiler generating plants are along the coastline or within estuaries to use sea water for cooling. There are a few similar plants at inland locations that use other water sources than the ocean. These are not subject to the SWRCB's OTC policy, which is limited to power plants using ocean and estuarine water sources.

24 California ISO, *Board Approved 2014-15 Transmission Plan*, pp. 147-149. http://www.caiso.com/Documents/Board-Approved2014-2015TransmissionPlan.pdf.

The Energy Commission's LCATT analyses for 2024 were extremely close to the California ISO's results. However, the LCAAT showed that the deficit began as soon as summer 2021. The Energy Commission urged the California ISO to study 2021 in the balance of its 2015-16 TPP effort, and the resulting California ISO studies confirmed deficits in that earlier period. In this 2016 LCAAT analysis, having California ISO results for 2021 and 2025 provides firm endpoints that LCAAT matches.

Compared to the results obtained using the LCAAT with the package of input assumptions developed for the 2014-15 TPP, the following comparisons can be made:

- Combined L.A. Basin/San Diego and L.A. Basin results are more positive. Deficits found in the 2015 LCAAT study are not found in this new study.
- Deficits in the West L.A. subarea, SD-IV, and San Diego subarea are substantially worse. In particular, the SD-IV results are much worse because of the much higher LCR values that the California ISO found in its 2015/16 TPP studies compared to its 2014/15 TPP studies.

Finally, for the 2016 LCAAT projections, the relatively small deficits in some local areas could easily be covered by "repurposing" demand response to make it useful to the California ISO, as the California ISO assumed in its 2015-16 TPP studies, or by adding other energy resources that have been authorized by the CPUC but not yet acted upon by SCE; for example, additional storage amounts that the CPUC directed in D.13-10-040. There are uncertainties in other assumptions that could drive the results in the opposite direction; for example, to worsen the baseline surplus/deficit projections in one or more areas. Chapter 4 describes a sensitivity study that evaluated the range that might occur for key input variables, an alternative set of projections for each variable, and the results of using these alternative inputs in LCAAT to determine impacts of surpluses/deficits. Some of these variables (such as base load forecast growth) reflect inherent uncertainties that cannot be controlled through policy, while others (such as AAEE) are generally thought to be influenced by policy-maker decisions that shape program design and thus the degree of customer participation through time.

CHAPTER 4: Assessing the Range Around Baseline Results Using Sensitivity and Scenario Studies

Alternative input assumptions to those selected for the baseline could increase or decrease the projected amounts or pattern of energy generation surpluses/deficits in one or more local areas. To gain a more complete understanding of the range of possible results, the Energy Commission performed sensitivity and alternative scenario assessments.

This section describes the specific values used to test sensitivity for each key variable, the increase or decrease of the alternative assumption relative to the baseline assumption, and some background for the variables.

Variable-Specific Sensitivity Cases

As with any planning tool, there are uncertain variables with future assumptions. Baseline assumptions are generally consistent with the CPUC 2014 LTPP assumptions or those used by the California ISO in its 2015–16 TPP. A set of sensitivity cases was developed to test the impacts of alternative assumptions for a limited set of variables.

Key variables tested are the following:

- Demand-side variables
    - Vintage of load forecast
    - AAEE
        - AAEE case
        - Success in achieving peak load savings
    - Peak shift impact on peak demand forecast
- Supply-side variables
    - Demand response effectiveness
    - Storage (integrated forward market only)
    - Transition of qualifying facilities (QFs) to wholesale generators
    - Peak shift impact on qualifying capacity (QC) of supply-side solar resources

Each variable tested in the sensitivity study was assessed using LCAAT with all other assumptions and parameters set at baseline values making these tests single-variable sensitivities. The discussion provides an overview about each variable intended to summarize issues giving rise to uncertainty about future projections.

Load Forecast

The baseline demand forecast is the mid-case 1:10 peak demand forecast without AAEE adopted in the *2014 IEPR Update*.[25] This demand forecast incorporates the impacts of committed energy efficiency programs, expected growth of rooftop photovoltaic (PV), load-modifying demand response programs, and other policies. Like any demand forecast, it is subject to uncertainties. The Energy Commission prepares and adopts annual demand forecasts in support of CPUC LTPP rulemaking and for various California ISO transmission planning proceedings.

Two sensitivities have been assessed for this project: (1) the *IEPR* cycle from which the demand forecast is derived; and (2) hypothetical growth higher than the mid-case normally used for planning. The increment of load for the first of these sensitivities is derived from the difference between the *2014 IEPR Update* baseline assumption and the *2015 IEPR* adopted mid-case (both using the mid-case base forecast without AAEE demand reductions). The latter is being assessed by the California ISO as part of the 2015–16 TPP cycle, so this sensitivity essentially presages the results of what will become the "baseline" for LCAAT when the next cycle of input assumption updates is made.[26]

A lower level of load growth provides an understanding of the extent to which lower load forecasts than those adopted by the Energy Commission affect the assessment of local capacity results of the LCAAT. **Table 4** compares the *2014 IEPR Update* versus the *2015 IEPR* 1:10 weather peak demand projections for each of the areas in LCAAT. All areas have substantially lower peak demand forecasts in the newer Energy Commission forecasts. All else being equal, these lower demand forecasts would likely result in smaller deficits or larger surpluses in the areas evaluated using the LCAAT, because previous California ISO studies have demonstrated that power flow modeling generally increased LCR requirements by about the same amount as load is increased; for

25 AAEE is subtracted from the baseline loads at the power flow modeling step so that the geographic distribution of the effects on local capacity area requirements can be modeled more accurately than if it were subtracted at the climate zone/regional level.

26 The California ISO released its LCTA reports for 2017 that use the adopted *2015 IEPR* peak demand forecast as an input into power flow modeling. Additional changes made by the California ISO mean that those results are not directly comparable to the LCAAT results using the 2015–16 TPP cycle of analyses. The California ISO's 2026 assessment of LCRs is forthcoming in November 2016 (preliminary) and February 2017 (final) as part of the 2016–17 TPP effort. Once these results are available, the entire package of assumptions for the LCAAT will be updated.

example, a 1:1 relationship.[27] In the current LCAAT model, the Energy Commission assumes that this relationship is symmetric; for example, load reductions **reduce** LCRs by a comparable amount.

Table 4: Comparing *2014 IEPR Update* and *2015 IEPR* Peak Demand Forecasts (MW)

	Area	**2017**	**2021**	**2025**
2015 IEPR	Total SCE TAC Area	25244	25295	25498
	L.A. Basin Subtotal	20144	20098	20141
	West L.A. Subarea	11905	11878	11903
	East L.A. Basin	8239	8220	8238
	San Diego	4920	4926	4969
2014 IEPR Update	Total SCE TAC Area	26696	28012	29145
	L.A. Basin Subtotal	21681	22781	23717
	West L.A. Subarea	12814	13464	14017
	East L.A. Basin	8868	9317	9700
	San Diego	5453	5698	5850
Increment (2015 IEPR-2014 IEPR)	Total SCE TAC Area	-1453	-2717	-3648
	L.A. Basin Subtotal	-1537	-2683	-3576
	West L.A. Subarea	-909	-1586	-2113
	East L.A. Basin	-629	-1098	-1463
	San Diego	-533	-772	-881

Source: California Energy Commission staff

Alternatively, higher growth sensitivity reflects slightly higher growth that could occur in one or more specific regions of Southern California. **Table 5** provides base and incremental values assuming peak load forecasts growth 0.5 percent per year faster than those adopted in the *2014 IEPR Update*. Over the forecast periods, this means 2021 peak loads would be 3.5 percent higher in 2021 than the base forecast and 5.5 percent higher in 2025 than in the baseline forecast. This is roughly one-half of the difference between the mid and high cases prepared by Energy Commission demand forecasting

27 California ISO, *Board Approved 2014 – 2015 Transmission Plan*, Appendix E, pp. 76-77. http://www.caiso.com/Documents/AppendixEBoardApproved2014-2015TransmissionPlan.pdf.

staff in the past two *IEPR* cycles. The difference is assumed to be zero in 2015 and to grow linearly by 0.5 percent annually. There are many explanations that could create this outcome; for example, committed energy efficiency savings not persisting as long as assumed, higher usage per customer reflecting more intensive electricity-using habits than assumed in the Energy Commission's demand forecasts, higher penetration of electric cars and the impact on loads at peak times, and so forth. Such phenomena are included within Energy Commission's demand forecasts and the incremental impacts, shown in **Table 5**, are only a portion of the possible range that could encompass the base and low-/high-case alternatives prepared by Energy Commission. Since the Energy Commission prepares these forecasts each year, however, there is a limited amount of error than can compound through time.

Table 5: Incremental Peak Load for High Growth Sensitivity (MW)

	Area	**2017**	**2021**	**2025**
2014 IEPR Update	Total SCE TAC Area	26696	28012	29145
	L.A. Basin Subtotal	21681	22781	23717
	West L.A. Subarea	12814	13464	14017
	East L.A. Basin	8868	9317	9700
	San Diego	5453	5698	5850
Increment for Higher Growth Assuming 1.02 Ratio by Year 2024	Total SCE TAC Area	27230	28573	29728
	L.A. Basin Subtotal	22115	23237	24191
	West L.A. subarea	13070	13733	14297
	East L.A. Basin	9045	9504	9894
	San Diego	5562	5812	5967

Source: California Energy Commission staff

Additional Achievable Energy Efficiency Planning Assumptions

The Energy Commission, CPUC, and California ISO have adopted as a planning practice the use of a "mid-low" set of AAEE projections for local capacity studies. In contrast, the agencies have agreed that the California ISO should use a "mid" set of AAEE projections for other transmission planning studies. The rationale for this difference is the sensitivity of local capacity study results to the precise location of load reductions and the inability of the energy efficiency program planning to assure that general purpose energy efficiency programs will achieve any specific geographic pattern of customer participation and/or results. An effort like SCE's Preferred Resource Pilot is required to assure participation in targeted locations.

To assess the sensitivity of LCAAT to the higher level of savings in the mid AAEE case compared to the low-mid AAEE case, **Table 6** identifies an increment of savings by location from use of the mid AAEE case. Generally, the L.A. Basin areas all increase the same percentage, the San Diego area increases at a larger percentage than the L.A. Basin areas, and the combined area increases slightly more than the L.A. Basin alone.

Table 6: AAEE Planning Assumption Sensitivity by Area and Subarea (MW, With Distribution Losses)

	Area	2017	2021	2025
2014 IEPR Update (low mid case)	Combined L.A. Basin/San Diego Subarea	490	983	1565
	L.A. Basin Subtotal	372	737	1164
	West L.A. subarea	280	543	854
	East L.A. Basin	118	245	401
	San Diego	118	245	401
2014 IEPR Update (mid case)	Combined L.A. Basin/San Diego Subarea	294	590	939
	L.A. Basin Subtotal	223	442	699
	West L.A. subarea	168	326	513
	East L.A. Basin	71	147	241
	San Diego	71	147	241
Increment 2014 IEPR Update (mid – low-mid)	Combined L.A. Basin/San Diego Subarea	196	393	626
	L.A. Basin Subtotal	149	295	466
	West L.A. subarea	112	217	343
	East L.A. Basin	47	98	160
	San Diego	47	98	160

Source: California Energy Commission staff

Realizing Energy Efficiency Savings Projections

AAEE is an important factor affecting LCR results because it reduces load, but also because the distribution across substations may be different than that of baseline loads. For example, the programmatic emphasis of AAEE is utility retrofit programs and the impacts of building and appliance standards. The industrial and agricultural sectors have much less emphasis in AAEE projections than do baseline load forecasts. Agricultural load is relatively unimportant for local capacity area studies because it takes place mostly outside the L.A. Basin and almost entirely outside the West Los Angeles subarea, but there are high concentrations of industrial load at some substations and little or no industrial load at other substations. In its local capacity studies, the California ISO incorporates AAEE savings distributed to substations according to a pattern developed by Energy Commission staff; thus, cases with AAEE projections shift power flows compared to cases without AAEE. [28]

The LCAAT cannot test the impacts of alternative AAEE distributional patterns within a local capacity area unless a full power flow study is completed. However, the LCAAT can assess the impact of different amounts of AAEE distributed in the same proportions as in full power flow studies—reflecting the basic uncertainty of whether end-use customers will engage in energy efficiency programs at the level now being assumed in agency planning studies.

Table 7 provides the *2014 IEPR Update* vintage of AAEE projections. AAEE ramps up over time, and more than 1,100 MW are assumed in the L.A. Basin and 400 MW in San Diego by 2025. These AAEE projections assume continuation of IOU retrofit programs, Energy Commission Title 20 Appliance Standards upgrades, and Energy Commission Title 24 Building Standard upgrades through time. A recently published CPUC report more thoroughly documents actual savings found from IOU programs for programs implemented in 2010 through 2012.[29] Among the results found from intensive evaluation, measurement, and verification (EM&V) studies is that peak savings per unit of energy savings are below the level assumed in developing the AAEE projections. Table 1 of that report shows that peak load impacts versus energy savings are substantially below the values assumed in the CPUC's adopted goals. Net evaluated savings achieved 844 MW, whereas gross goals assumed 1,537 MW, which is a 45.1 percent shortfall. This is the same rationale as was used in the 2015 LCAAT study because no subsequent evaluated savings results for 2013 to 2015 energy efficiency programs is yet available at the time of the 2016 study.

To assess the impact of this facet of AAEE uncertainty, a sensitivity case was designed that assumes a reduction in all future years of 40 percent of future expected AAEE peak load savings for the mid-low AAEE case.[30] This sensitivity assumes the same level of

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28 Power flow modeling techniques are used by the California ISO and by transmission system developers to simulate how power might actually flow on the transmission system. Various contingencies are defined that would stress elements of the system by overloading specific transmissions lines, or affect the ability of the system to maintain voltage stability. Loads and adjustments to loads, such as AAEE projections, must be defined at the level of high-voltage substations, if not with greater granularity, to be accurate about these estimates of power flow.

29 CPUC, *2010-2012 Energy Efficiency Annual Progress Evaluation Report*, March 2015.

30 *Peak load savings* are all that is relevant in local capacity studies. By design, August peak LCR values are the basis for year-round requirements in load-serving entities as part of the resource adequacy program.

effort is undertaken with the same success in getting retail customers to achieve energy savings, but fewer peak load savings occur as a result. This could occur because program participants “take back” some of the energy savings at peak conditions through increased comfort levels, differences in the mix of measures resulting in less on-peak load reductions than assumed in AAEE projections, or other similar reasons. **Table 7** provides the assumed peak load reductions of this 40 percent shortfall.

Table 7: AAEE Realization Sensitivity (MW)

	Area		**2017**	**2021**	**2025**
2014 IEPR Update	Combined L.A. Basin/San Diego Subarea		490	983	1565
(low mid case)	L.A. Basin Subtotal		372	737	1164
	West L.A. subarea		280	543	854
	East L.A. Basin		118	245	401
	San Diego		118	245	401
Sensitivity	Combined L.A. Basin/San Diego Subarea		294	590	939
(60% of Baseline)	L.A. Basin Subtotal		223	442	699
	West L.A. subarea		168	326	513
	East L.A. Basin		71	147	241
	San Diego		71	147	241
Increment	Combined L.A. Basin/San Diego Subarea		196	393	626
(40% Reduction)	L.A. Basin Subtotal		149	295	466
	West L.A. subarea		112	217	342
	East L.A. Basin		47	98	160
	San Diego		47	98	160

Source: California Energy Commission

Southern California Edison Request for Offer Preferred Resources

Under the direction provided in CPUC D.14-03-004, SCE conducted an all-source RFO and submitted a package of preferred resource PPAs to the CPUC for approval.[31] SCE acquired five types of preferred resources in this RFO:

- Energy efficiency
- Energy storage BTM
- Renewable distributed generation BTM
- Demand response
- Energy storage projects connected on the utility side of the meter

Demand response and energy storage in front of the meter are treated in LCAAT as a supply resource, but the first three items are treated as load modifiers.

There were three issues with the numerous small contracts SCE submitted to the CPUC for approval in November 2014. First, will these projects be approved? Second, if approved, will projects be developed on the schedule assumed? Third, for the projects that are developed, how will they perform in terms of summer peak load reductions?

The CPUC resolved the first by approving the majority of the PPAs and rejecting a few. The project development and performance questions remain. The structure of the contracts that SCE has with the project developers reveals some uncertainty about results—the contracts call for a minimum delivery of 50 percent of the nominal capacity reductions. Within the portfolio of proposed PPAs, only energy efficiency projects have some short contract terms. For energy efficiency PPAs with short contract terms (4 to 6 years), Energy Commission assumed that measure savings would decay at a rate of 10 percent per year following the end of the contract period. No other category of program had such short-term contracts, so there is no comparable reduction for energy storage or distributed generation following completion of the contract term.

Table 8 provides two sets of projections: (1) baseline projections, a summary of the capacity development patterns assuming all contracts are approved and that all contracts are successfully developed on the schedule submitted to the CPUC; and (2) a sensitivity projection, in which not all of the contracted resources will be approved or, if approved, develop to the full contracted capacity. The value of 0.72 is obtained as the product of two assumptions: (1) only 90 percent of projects will be approved; and (2) of the projects approved, only 80 percent of the contracted capacity will be achieved. Clearly, many other assumptions could be made.

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31 SCE submitted its proposed PPAs to the CPUC in November 2014 as Application 14-11-012.

Table 8: SCE RFO Preferred Resource Performance Patterns (MW, With Losses, by Type)

	Contract Amount	2016	2020	2024
Baseline				
EE	124	5	128	95
ES BTM	164	0	172	172
Renewable DG BTM	38	0	40	40
Total	326	5	340	307
Sensitivity (0.72 of Baseline)				
EE	124	4	92	68
ES BTM	164	0	124	124
Renewable DG BTM	38	0	29	29
Total	326	4	245	221
Increment				
EE		1	36	27
ES BTM		0	48	48
Renewable DG BTM		0	11	11
Total		1	95	86

Source: California Energy Commission staff

The results of **Table 8** are modest in comparison to other variables; therefore, in the 2016 update of the LCAAT, this sensitivity was not exercised although the LCAAT retains the capability to assess these impacts on area-specific surpluses or deficits.

Demand Response Effectiveness

An important input assumption is the level of demand response in each of the load pockets, subareas, and the overall L.A. Basin/San Diego combined area. Although the CPUC has prepared projections of demand response that approximate existing program capabilities and requested that the California ISO use these in its transmission planning, the California ISO has asserted that only demand response in the southern Orange County area and only those programs capable of providing a response within 20 minutes are effective in addressing the contingency consequences they find drive local capacity values in the combined area.[32] By filtering existing demand response

32 CPUC, Comments of the Staff on the 2014-15 TPP Draft Unified Assumptions and Study Plan Posted February 20, 2014, http://www.caiso.com/Documents/CPUCCommentsDraft2014-2015StudyPlan.pdf.

capabilities for the subset that are “fast” and “effective,” the resulting amounts are much smaller than the full capability of existing programs operated by SCE and SDG&E. The LCAAT uses California ISO assumptions as the baseline input but can compute the consequences of three alternative sets of demand response assumptions.

Table 9 shows the CPUC’s projected demand response capabilities, the subset that the California ISO believes are both “fast” and “effective” for various regions, and a moderate amount that is halfway in between. **Table 9** values exclude the 75 MW of demand response that SCE procured through its 2014 RFO, since the CPUC in D.15-11-041 did not approve these contracts.[33]

Storage

Storage is one of the variables in which there is a difference between CPUC 2014 LTPP assumptions and California ISO 2015–16 TPP study assumptions. Since the California ISO LCR values are based on the California ISO’s own assumption about the penetration of storage resources, they were adopted as the baseline input assumptions for the LCAAT.

To develop sensitivity assumptions to explore the implications of larger storage amounts, the storage procurement decision made by the CPUC in fall 2013 was the starting point.[34] D.13-10-040 does not allow customer storage values to affect compliance with transmission or distribution values, so the amounts of BTM storage acquired by SCE in its 2014 all-source RFO that exceed the customer storage target in D.13-10-040 do not offset required transmission or distribution storage targets. Further, two-hour storage does not count for resource adequacy, so the proportions of two-hour storage established in the refreshed scenarios and assumptions included in the Assigned Commissioner’s Ruling of the 2014 LTPP rulemaking[35] were used to discount the remaining storage target values for use in the LCAAT sensitivity assessment.[36] SDG&E was also provided a “credit” for the two Lake Hodges units totaling 40 MW of its 80 MW transmission-level target.

33 CPUC D.15-11-041 found that six of the NRG contracts, totaling 70 MW, do not constitute demand response and fail to constitute preferred resources under D.13-02-015 and D.14-03-004 because they rely upon behind-the-meter natural gas-fired generation and are therefore inconsistent with the state’s loading order preferences. A seventh contract for 5 MW lacked full information, but the CPUC conditionally approved the contract, provided that SCE submitted the missing information within 45 days.

34 CPUC D.13-10-040, Table 2, page 15.

35 CPUC R.13-12-010, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M147/K780/147780118.PDF.

36 CPUC, 2014 LTPP, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M147/K780/147780118.PDF.

Table 9: Alternative Demand Response Program Capability Projections by Area (MW, With Loss Credit)

	2014	2020	2024
Effective Projections			
Combined L.A. Basin/S.D. Area	180	197	203
L.A. Basin	162	177	182
West L.A. (Effective)	162	177	182
West L.A. (Less Effective)	0	0	0
Eastern-Metro Subarea	0	0	0
Eastern Subarea Balance	0	0	0
San Diego Subarea	18	21	21
Moderate Demand Response Capability Projections			
Combined L.A. Basin/S.D. Area	482	527	542
L.A. Basin	464	507	521
West L.A. (Effective)	162	177	182
West L.A. (Less Effective)	165	180	185
Eastern-Metro Subarea	126	137	141
Eastern Subarea Balance	12	13	13
San Diego Subarea	18	21	21
Full Capability Projections			
Combined L.A. Basin/S.D. Area	784	857	882
L.A. Basin	767	837	861
West L.A. (Effective)	162	177	182
West L.A. (Less Effective)	329	360	370
Eastern-Metro Subarea	251	275	282
Eastern Subarea Balance	24	26	27
San Diego Subarea	18	21	21

Source: California Energy Commission staff

Table 10 summarizes the original cumulative targets that must be operational by 2024, adjustments and the LCAAT baseline assumptions, a revised cumulative target after such adjustments, and the remaining increment of D.13-10-040 that was tested as a sensitivity case.[37]

Table 10: Comparison of Baseline and Sensitivity Projections for Storage in 2024 (MW)

IOU Area	Storage — Point of Interconnection	Original Cumulative Target	Existing Resource Adjustments	LCAAT Baseline Assumptions	Revised Cumulative Target	Increment for LCAAT Sensitivity[38]
SCE	Transmission	310	0	100	210	165
	Distribution	185			185	148
	Customer	85	0	162	0	0
	Subtotal SCE	580	0	262	395	313
PG&E	Transmission	310			310	244
	Distribution	185			185	148
	Customer	85			85	64
	Subtotal PG&E	580	0		580	456
SDG&E	Transmission	80	40	25	15	12
	Distribution	55			55	44
	Customer	30	0	100	0	0
	Subtotal SDG&E	165	40	125	70	56
IOU Total	Transmission	700	40	125	535	422
	Distribution	425	0	0	425	340
	Customer	200	0	262	85	64
	Total – All IOUs	**1,325**	**40**	**387**	**1,045**	**825**

Source: California Energy Commission staff

Renewables Portfolio Standard Portfolio

Although utility plans for compliance with statutory mandates to achieve 33 percent of applicable energy using renewable generation by 2020 are well along, there is still uncertainty about the portfolios that will ultimately develop. In the 2015 LCAAT study, a sensitivity that tested the local capacity area implications of the two portfolios

37 Storage values for 2025 were extended from 2024 values.

38 The increment for LCAAT sensitivity incorporates an adjustment for the two-hour discount for resource adequacy purposes.

prepared by the CPUC's Energy Division (CPUC/ED) and forwarded jointly by the CPUC and Energy Commission to the California ISO for use in the 2014–15 TPP.[39]

Table 11 provides an overview of the two portfolios for areas of interest in Southern California for 2024. Several important things can be seen from **Table 11**. There are essentially no central station renewables in any area of interest except SD-IV. Compared to load, central station renewables capacity in the L.A. Basin load pocket or associated subareas is very small. Central station renewables are a higher proportion of load in the SD-IV load pocket, but the renewable projects are almost entirely in the Imperial Valley, not in the more populated San Diego subarea. Furthermore, the difference between the two portfolios is mainly in DG, not in supply-side renewables, and that this difference is numerically important in L.A. Basin and West Los Angeles subarea. It is not an important difference for either of the two San Diego areas. Unfortunately, the DG differences between these two scenarios were artificially inserted by CPUC/ED and do not reflect the operation of the portfolio generating tool itself.

Since the 2015 LCAAT study was analyzed, Senate Bill 350 (de León, Chapter 547, Statutes of 2015) was signed by Governor Brown, and the issues before the electricity industry are compliance with an RPS mandate of 50 percent by 2030. CPUC/ED has developed a new generation of RPS calculator, which is evolving. No new RPS portfolios were transmitted by the CPUC and Energy Commission for the 2016-17 TPP process; instead, the same RPS portfolios developed for earlier cycles were offered for study again.[40] The Renewable Energy Transmission Initiative (RETI) 2.0 process[41] is attempting to create additional environmental/land-use analysis parallel to the *Desert Renewable Energy Conservation Plan* studies to guide future renewable development.[42]

Because existing RPS portfolios have limited relevance to local capacity area analyses and there are no new RPS portfolios, no sensitivity for RPS development patterns was assessed for the 2016 LCAAT study.

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39 CPUC and Energy Commission, Joint Transmittal Letter Dated February 27, 2014, http://www.caiso.com/Documents/2014-2015RenewablePortfoliosTransmittalLetter.pdf

40 CPUC, R.15-02-020, ALJ Ruling, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M159/K360/159360237.PDF.

41 RETI 2.0 is an open, science-based process that will explore the abundant renewable generation resources in California and throughout the West, consider critical land use and environmental constraints, and identify potential transmission opportunities that could access and integrate renewable energy with the most environmental, economic, and community benefits. http://www.energy.ca.gov/reti/index.html.

42 Energy Commission, RETI 2.0 documents, http://www.energy.ca.gov/reti/reti2/documents/.

Table 11: Comparison of RPS Portfolios by Area in 2024 (MW)

Net Qualifying Capacity	33% Trajectory Mid-AAEE	33% High DG + DSM	Difference
L.A. Basin			
DG	222	904	682
Central Station Renewables	14	7	-7
West L.A. Basin			
DG	209	785	576
Central Station Renewables	0	0	0
Eastern L.A. Basin			
DG	13	119	106
Central Station Renewables	14	7	-7
San Diego-Imperial Valley			
DG	78	86	8
Central Station Renewables	399	399	0
San Diego			
DG	78	86	8
Central Station Renewables	0	0	0

Source: California Energy Commission staff

Transition of Cogeneration Qualifying Facilities to Wholesale Generators

In D.10-12-035, the CPUC adopted the "Qualifying Facility and Combined Heat and Power Settlement Agreement," which resolved outstanding disputes between utilities and QFs and established a new combined heat and power (CHP) procurement program through 2020.[43] D.10-12-035 provides for an orderly transition from the existing QF program as a federal jurisdiction standard-offer pricing model under the Public Utility Regulatory Policies Act to a new QF/CHP program under state jurisdiction using a market-based approach for pricing.[44] Through a sequence of utility CHP RFOs, the utilities were to procure CHP competitively using market-based pricing. The settlement

43 A *qualifying facility* is a cogenerator or small power producer that, under federal law, has the right to sell its excess power output to the public utility. http://www.energy.ca.gov/glossary/glossary-q.html.

44 CHP plants less than or equal to 20 MW are eligible for two programs with different energy pricing terms: the Assembly Bill 1613 Export Feed-in Tariff (Blakeslee, Chapter 713, Statutes of 2007) and the standard offer contract approved in the QF/CHP Settlement with short-run avoided cost pricing. CHPs larger than 20 MW are subject to competitive procurement and may (but do not automatically) receive compensation for exports at short-run avoided cost.

agreement was also written to promote new, lower greenhouse gas- (GHG) emitting CHP facilities and encourage the repowering, operational changes through utility-prescheduling, or retirement, of existing, higher GHG-emitting CHP facilities in an effort to optimize the state's existing CHP as a GHG emissions reduction strategy.

The utilities have made progress in meeting the interim goals of the program, and new program goals have been set in D.15-06-028 to provide regulatory certainty to the CHP community. Though new program goals have been set, not all parties agree, and some feel there is uncertainty surrounding the viability of existing CHP plants. As contracts end, CHP facilities face the uncertainty of being able to recontract. The utilities no longer have the must-take obligation under the Public Utilities Regulatory Policies Act of 1978 (PURPA) for large facilities greater than 20 MW.[45] Those plants able to recontract may repower or convert to a utility prescheduled facility in which the power plant converts baseload generation to utility-controlled, dispatchable generation. Other options available to CHP facilities are to obtain a new PPA, sell into the wholesale market, shut down, or stop exporting. One of the potential outcomes is that a CHP plant is unable to recontract and shuts down, and the owner installs a boiler and buys power from the local utility. This scenario puts upward pressure on demand while decreasing the generating supply. Facilities, whose thermal host steam needs are declining, may also shut down, putting further downward pressure on the generating supply. All parties agree on one issue—the existing cohort of inefficient, high GHG-emitting facilities, including those that use coal, petroleum coke, or diesel, is expected to retire or repower.

A sensitivity that captures the uncertainty surrounding CHPs as they transition from CHP QFs under PURPA to wholesale generators under the new state CHP program can be conducted using a change to the retirement assumption for CHP. **Table 12** presents the retirement assumptions for the baseline case and a sensitivity case for CHP. The baseline retirement assumption in the LCAAT is based on the CPUC Assigned Commissioner's Ruling detailing assumptions and scenarios for use in the 2014 LTPP and 2014–15 TPP[46] and used a 40-year life span assumption for conventional generators and cogeneration (not including OTC facilities that are assumed to retire on schedule with SWRCB compliance dates) in the mid-level assumption. In this sensitivity, the retirement assumption is changed to 35 years for cogeneration. The LCAAT allows testing of varying retirement assumptions for different technologies. Changing thermal technologies retirement assumption to 35 years does not affect the L.A. Basin local area

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45 PURPA is federal legislation that, among other things, requires utilities to buy electric power from private "qualifying facilities" at an avoided cost rate. This avoided cost rate is equivalent to what it would have otherwise cost the utility to generate or purchase that power themselves. Utilities must further provide customers who choose to self-generate a reasonably priced backup supply of electricity. http://www.energy.ca.gov/glossary/glossary-p.html.

46 R.13-12-010 Commissioner Picker Ruling, released February 27, 2014, available online at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M088/K489/88489746.PDF.

during the period assessed here. **Table 13** presents the impact to cogeneration or CHP by using a 35-year retirement assumption, which shows that 428 MW more capacity is retired by 2024 in the L.A. Basin.

Table 12: Assumed Lifetimes for Generating Technologies (Years)

Technology	Lifetime in Years	
	Base Case	CHP Sensitivity
Biomass	40	40
Cogeneration	40	35
Geothermal	40	40
Hydro	70	70
Peaker	40	40
Pump	50	50
Solar	25	25
Thermal	40	40
Wind	25	25

Source: CPUC, 2014 LTTP, ACR dated March 3, 2015

Table 13: CHP Capacity Retired Assuming Alternative Technology Lifetimes (MW)

MW Cogeneration Retirement by Local Area	Lifetime 40 Years		Lifetime 35 Years		Difference in Computed Retirements using 35-40 year Life	
	2020	2025	2020	2025	2020	2025
L.A. Basin	0	60	60	182	60	122
W L.A. Basin	0	29	29	96	29	67
Eastern Metro	0	31	31	86	31	55
San Diego	0	10	0	78	0	68

Source: California Energy Commission staff

Peak-Hour Shift

Peak-hour shift results from BTM rooftop PV systems satisfying different amounts of BTM consumption across the hours of the day. This offset of purchases from the grid is largest in the early afternoon, diminishes as the day wears on, and rapidly drops off near sunset. This shift can result in grid-supplied system peaks at a later hour of the day and at a higher level than have been included within Energy Commission's demand forecasts to date. Preliminary staff analyses released at the June 23, *2016 IEPR Update* demand forecast workshop confirm that this phenomenon exists but is more complex than utilities have suggested. The availability of hourly projections for AAEE savings is another source of load reduction that varies from hour to hour and that may shift system peak. Irregular electric vehicle charging is yet another factor. Energy Commission proposes to examine the impacts of peak-hour shift on increasing load **and** decreasing available generation from central station solar systems in the local capacity area.

Energy Commission staff conducted analyses to determine the change in peak demand for the SCE and SDG&E service areas.[47] A seven-day period surrounding the actual September 2015 peak days of SCE and SDG&E was examined initially. After reviewing results, some days were dropped from further consideration because they were weekends and holidays. The remaining days, even though they immediately surround the annual peak day, reveal considerable daily variation. Using accurate hourly BTM PV production profiles reveals that peak day loads are a function of the interaction between complex customer behavior affecting load and solar production variability from weather/cloud cover.[48] Assuming the same patterns of weather and customer behavior that occurred on these days in September 2015 can be projected into the future, this analysis shows considerable variation among these days.

Table 14 provides the day-specific peak load increases for SDG&E for 2020 and 2026. Four days beginning September 8 were evaluated using actual SDG&E hourly system load data and hourly BTM PV production derived from SDG&E's BTM residential PV load research sample. Hourly consumption was projected forward to 2020 and 2026 on an hourly basis. From this peak day shape, the impact of BTM rooftop PV capacity projected for each year was subtracted from each hour. The consumption load forecast less the impact "on peak" of the BTM PV capacity yields a peak forecast similar to the method used to develop the *2015 IEPR* peak demand forecasts. These are the rows of **Table 14** highlighted in yellow. An alternative method subtracted from the hourly consumption forecast an hourly BTM PV profile estimated for 2020 or 2026 using the capacity ratio of Energy Commission's *2015 IEPR* demand forecast applied to the shape for that day from the 2015 SDG&E BTM PV load research sample. These lines are highlighted in red. The increase in peak value for each day by using the hourly BTM PV shape method less the results using the *2015 IEPR* method and the average of three highest peak days are shaded in blue. For SDG&E, the peak load increase in 2020 averages 5 MW, while it averages 84 MW in 2026. As expected, the impact on peak load is much larger in 2026 than 2020 since there is a considerable increase in BTM PV capacity in Energy Commission's *2015 IEPR* demand forecast. Energy Commission staff

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47 Change in peak demand here means comparing peak values developed using the method for the *2015 IEPR* demand forecast (assumes 40 percent of BTM rooftop PV capacity is the solar output at the 2015 observed hour of utility system peak) with a method that assumes the 2015 utility hourly load profile can be scaled into the future using annual energy consumption ratios and from this "consumption load" is subtracted an hour-specific BTM PV production profile obtained from data for each utility.

48 SDG&E provided its load research sample of residential behind-the-meter rooftop photovoltaic systems to Energy Commission's Energy Assessments Division staff in April 2016.

excluded from this averaging the negative peak load increment for September 11, since in both methods the projected peak load for this day was much lower than the other days assessed. The right-hand column of **Table 14** identifies the final values that were used in the peak-shift sensitivity case for 2020 and 2026. In the LCAAT itself, the intermediate years were linearly interpolated between 2020 and 2026.

Table 15 shows the analysis and final peak load increases used for SCE. **Table 15** is formatted exactly like **Table 14**, but two days in 2020 did not move a shift in the peak hour between the two methods. When the method using hourly BTM PV production data finds a shift in the hour of peak, this can be explained by the hourly consumption forecast dropping faster from the 2015 hour of peak than the BTM solar PV production profile drops off. When this is the case, the hour of peak will not change, although the amount of the peak can change. For September 8 and 9, the 2020 analysis shows modest increases in the hourly method compared to the method used in the *2015 IEPR* peak demand forecast. These days are shaded in lavender. Finally, for SCE, **Table 15** shows that all four days assessed were used to compute the average peak load increase because they had similar final peak loads. The increments for each day and the average used in LCAAT are shaded in blue.

Table 14 and **Table 15** also show the shift in the hour of the peak, as well as the amount of peak load shift. The shift in hour of peak is critical to understanding the supply-side consequences of the peak shift phenomenon. These peak hour shifts can be visualized using **Figure 2** through **Figure 5**. For SCE, **Figure 2** and **Figure 3** show no appreciable shift in hour of peak by 2020 but a one-hour shift by 2026. For SDG&E, **Figure 4** and **Figure 5** show a one-hour shift by 2020 and a two-hour shift by 2026.

The consequences of these shifts in SCE and SDG&E system peak hour, blended with any corresponding shift in peak hour for PG&E, will determine overall California ISO-wide issues for determining appropriate capacity value for central solar and wind resources. Of more direct interest in the context of the LCAAT analyses are the implications for renewable energy resources within the portions of the SCE and SDG&E service areas that are within local capacity areas. The LCAAT baseline summary tables in Chapter 3 reveal that only negligible amounts of solar and wind capacity are within the L.A. Basin or related subareas. Similarly, only one supply-side solar facility is within, or planned for, the San Diego subarea of the SD-IV local capacity area. However, a large amount of supply-side solar capacity is counted as part of the SD-IV local capacity area. Thus, for this LCAAT sensitivity analysis, Energy Commission focused on the dozen or so supply-side solar PV projects connected in SD-IV.[49]

49 According to production data submitted by the California ISO to the Energy Commission, 12 central station solar renewable facilities generated in SD-IV during some or all of calendar 2015. Some had reached full capacity prior to 2015, while others operated commercially during the building of project capacity to the ultimate project capability.

The Energy Commission believes that the peak hour shifts require examination of the consequences on renewable generation in later hours of the day than the current protocol for determining QC. The official protocol uses hourly data for hour ending (HE) at 2 p.m. through 6 p.m. (HE14-HE18) to compute QC values from actual hourly generator output data.[50] Using actual calendar year 2015 hourly production data, Energy Commission computed QC values using both the official time interval, a single-hour shift (for example, HE15-19), and a two-hour shift in this interval (for example, HE16-20) for the existing supply-side solar in Imperial Valley that is part of the SD-IV local capacity area.[51] **Table 16** provides these results for each month from April through October when the QC method assumes an afternoon peak. For local resource adequacy, August and September are the months of greatest interest.

Table 16 shows that capacity reductions of 36 percent for a single-hour delay in peak growing to an 85 percent reduction for a two-hour delay in peak should be expected in August and September. For LCAAT sensitivity assessment and for SD-IV, the single-hour impacts were assumed to occur in 2020, and the two-hour impacts were assumed to occur by 2026. Years in between were linear interpolations between these values. For L.A. Basin central solar resources, the impacts of the single-hour delay were assumed to occur by 2020 and remain at this value thereafter.

The SD-IV local capacity area has by far the largest proportion of renewable generation of total supply resources of any local capacity area in the California ISO. Therefore, the local capacity consequences of this issue are likely to be focused on SD-IV and perhaps on the combined region of SD-IV and L.A. Basin. However, the growing amounts of solar PV generation in the entire California ISO require that this shift in peak hour be addressed regardless of the capacity assessments method, whether exceedance[52] or effective load-carrying capability (ELCC).[53]

50 CPUC, R.14-10-010, *Revised QC Modeling Manual.* http://www.cpuc.ca.gov/General.aspx?id=6311.

51 Facility-specific hourly production data was used as obtained from the data subpoena that the Energy Commission issues to the California ISO each year. The facility-specific data are confidential, but aggregated results can be published.

52 An exceedance method is used by the CPUC to determine net quality capacity of a resource. In this method, the hourly production from the time interval that qualifies is rank ordered from highest to lowest. The QC value is the one that is exceeded 70 percent of the hours.

53 The legislature mandated that the CPUC shift from the exceedance method to the ELCC method for wind and solar resources. ELCC is a complex method that uses probabilistic analyses to establish times when an electric system is stressed. In the ELCC approach, the capacity value of individual resource technologies is greater the more their production profile matches the times of system stress.

Table 14: Peak-Load Increase for SDG&E Service Area in 2020 and 2026 (MW)

		SDG&E Peak Load Shift Analysis							
Date	Year	Hour	Consumption Load Projection	Fixed 40% Reduction	Baseline Load Forecast	Hourly PV Prod Profile	Improved Hourly Load Forecast	Day's Peak Load Increase	Average Peak Load Increase
9/8	2020	HE16	5109	332	4777	480	4629		
		HE18	4827	332	4495	155	4672	-105	
9/9	2020	HE14	5261	332	4929	589	4672		
		HE16	5166	332	4834	331	4835		
		HE20	4972	332	4640	3	4969	135	5
9/10	2020	HE15	5139	332	4807	401	4738		
		HE17	4992	332	4660	199	4793	-14	
9/11	2020	HE15	4969	332	4637	508	4461		
		HE17	4744	332	4412	245	4499	-138	
9/8	2026	HE16	5429	560	4869	786	4643		
		HE18	5129	560	4569	254	4875	6	
		HE20	4871	560	4311	5	4866		
9/9	2026	HE14	5590	560	5030	965	4625		
		HE16	5489	560	4929	541	4948		
		HE18	5229	560	4669	238	4991	62	84
9/10	2026	HE15	5461	560	4901	657	4804		
		HE17	5304	560	4744	327	4977		
		HE20	5091	560	4531	5	5086	185	
9/11	2026	HE15	5280	560	4720	832	4448		
		HE17	5041	560	4481	403	4638	-82	
		HE20	4596	560	4036	5	4591		
Legend for Color Coding:									
		Peak hour recorded in 2015							
		Shifted peak hour							
		No shift from 2015							
		Calculate peak Increase							

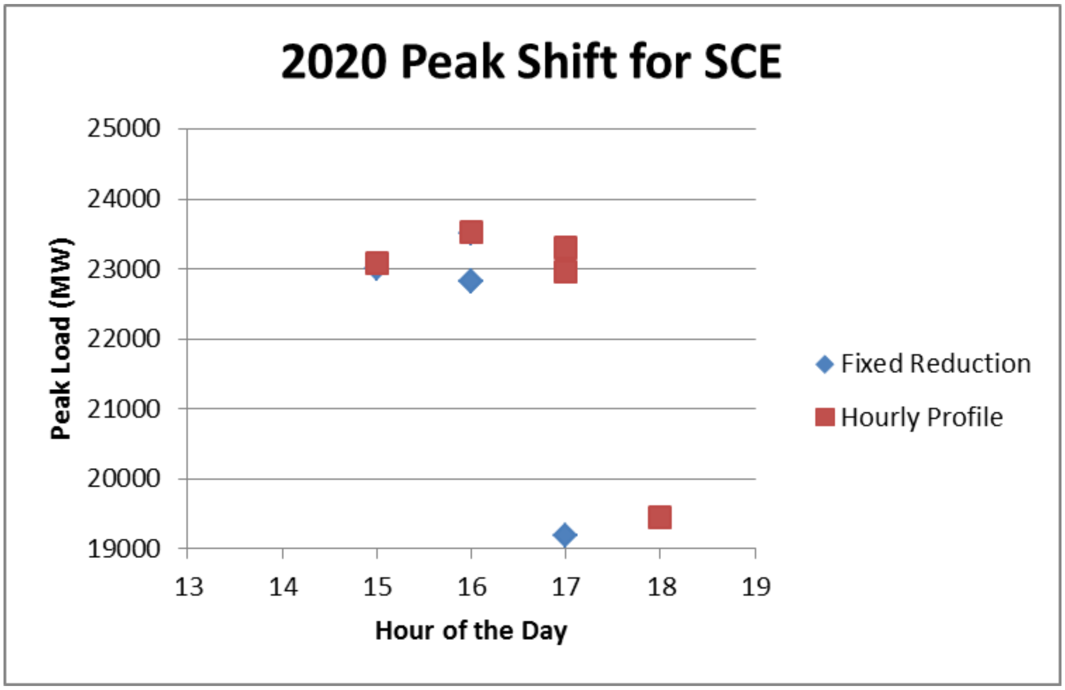
Source: California Energy Commission staff

Table 15: Peak-Load Increase for SCE Service Area in 2020 and 2026 (MW)

Date	Year	Hour	Consumption Load Projection	Fixed 40% Reduction	Baseline Load Forecast	Hourly PV Prod Profile	Improved Hourly Load Forecast	Day's Peak Load Increase	Average Peak Load Increase
		SCE Peak Load Shift Analysis							
9/8	2020	HE15	23949	905	23044	1251	22698		
		HE16	24405	905	23500	873	23531	32	
		HE17	23819	905	22915	433	23386		
9/9	2020	HE14	24090	905	23185	1048	23041		
		HE15	23916	905	23011	829	23087	76	
		HE16	23316	905	22411	633	22683		
9/10	2020	HE15	23400	905	22495	1056	22344		185
		HE16	23718	905	22813	778	22940		
		HE17	23688	905	22783	380	23308	495	
9/11	2020	HE15	23578	905	22673	1258	22320		
		HE16	23732	905	22827	892	22840		
		HE17	23386	905	22482	424	22962	135	
9/8	2026	HE15	25276	1760	23516	2433	22843		
		HE16	25757	1760	23997	1698	24058		
		HE18	25139	1760	23379	843	24297	300	
9/9	2026	HE13	24518	1760	22758	2749	21769		
		HE14	25425	1760	23665	2039	23385		
		HE15	25241	1760	23481	1611	23202	537	
9/10	2026	HE16	25032	1760	23272	1514	23518		563
		HE17	25000	1760	23240	738	24262		
		HE18	24269	1760	22509	154	24115	843	
9/11	2026	HE15	24885	1760	23125	2448	22437		
		HE16	25047	1760	23287	1734	23313		
		HE17	24682	1760	22922	825	23857	570	
Legend for Color Coding:									
		Peak hour recorded in 2015							
		Shifted peak hour							
		No shift from 2015							
		Calculate peak Increase							

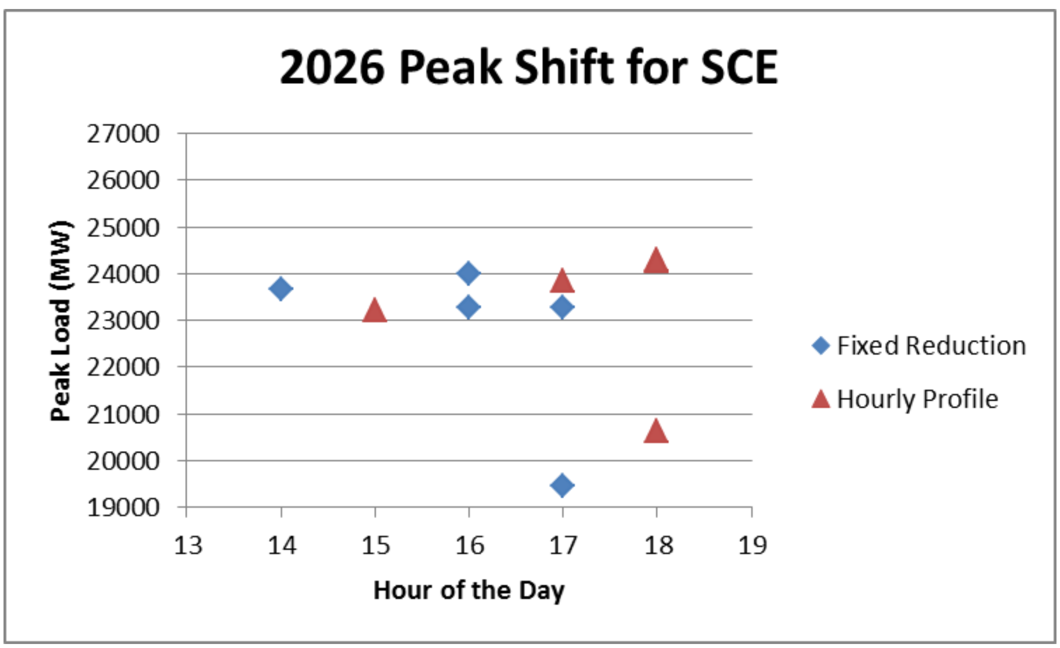
Source: California Energy Commission staff

Figure 2: SCE 2020 Shift in Hour of Peak



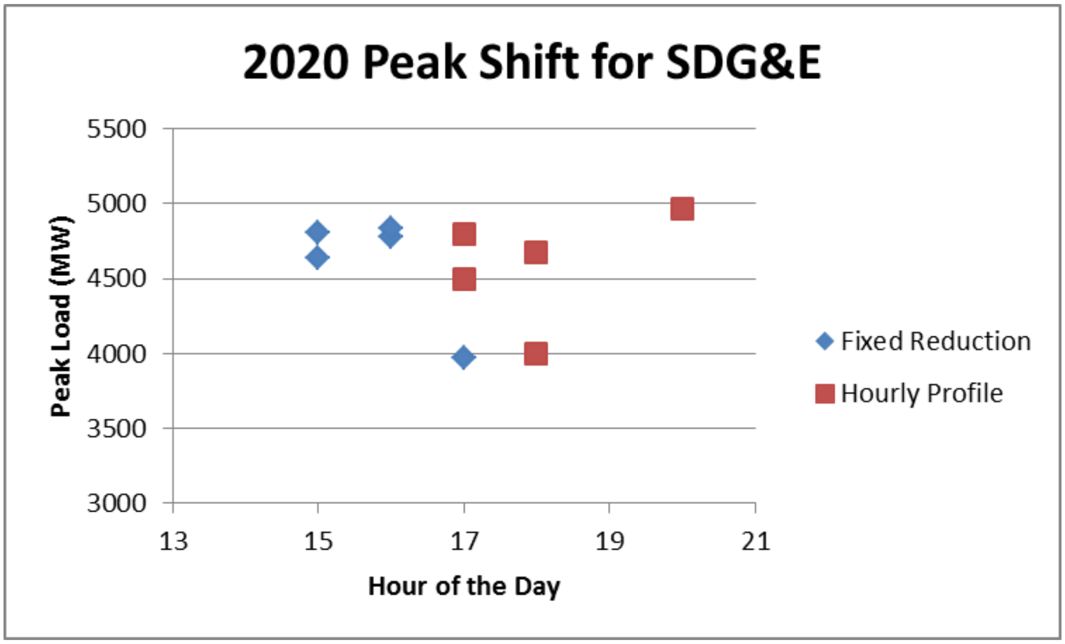
Source: California Energy Commission staff

Figure 3: SCE 2026 Shift in Hour of Peak



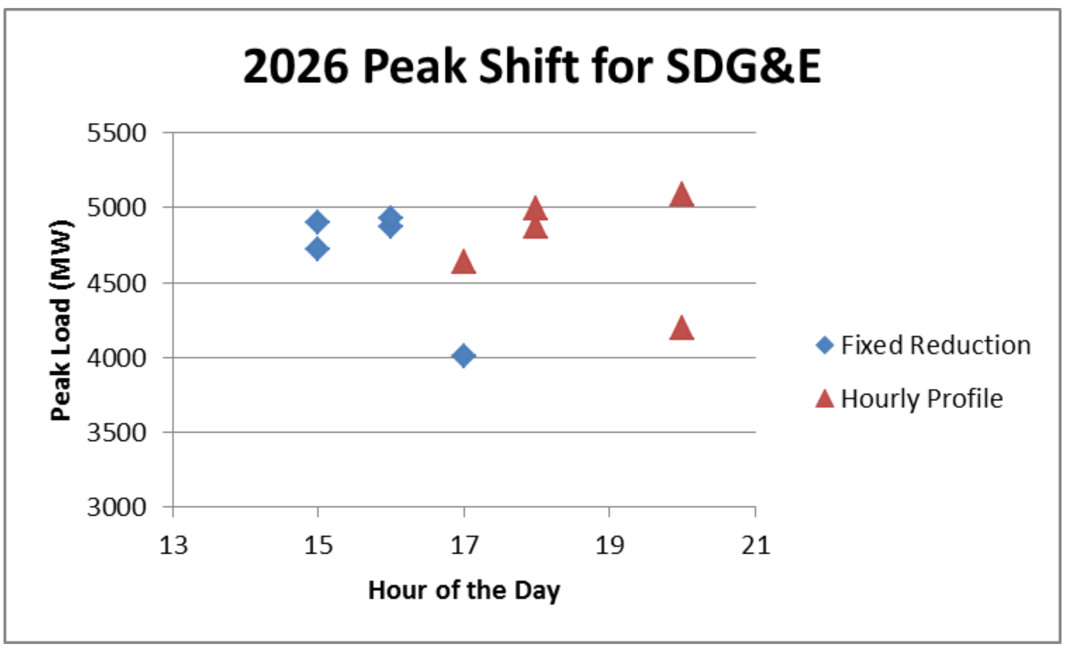
Source: California Energy Commission staff

Figure 4: SDG&E 2020 Shift in Hour of Peak



Source: California Energy Commission staff

Figure 5: SDG&E 2026 Shift in Hour of Peak



Source: California Energy Commission staff

Table 16: Reduction in Capacity by Shifting Hours for the Exceedance Method

Monthly Qualifying Capacity Values for SD-IV Central Solar Generators in Megawatts (2015 Data Only)							
Single Hour Shift vs. Standard	Month of the Year						
	4	5	6	7	8	9	10
Standard Hours (HE14-HE18)	521	479	451	466	497	310	287
Shifted Hours (HE15-HE19)	351	334	301	217	345	171	71
Reduced Capacity Value	171	145	150	250	152	139	216
Percent Reduction	32.7%	30.3%	33.2%	53.6%	30.6%	44.8%	75.4%
Avg % Reduction Aug-Sept					36.1%		
Two Hour Shift vs. Standard	Month of the Year						
	4	5	6	7	8	9	10
Standard Hours (HE14-HE18)	521	479	451	466	497	310	287
Shifted Hours (HE16-HE20)	78	121	179	114	109	24	0
Reduced Capacity Value	443	358	272	353	388	286	287
Percent Reduction	85.0%	74.7%	60.2%	75.7%	78.1%	92.3%	100.0%
Avg % Reduction Aug-Sept					83.5%		

Source: California Energy Commission staff

CHAPTER 5: Sensitivity and Scenario Assessments

To evaluate the effect of alternative assumptions on the LCAAT results, both sensitivity studies and scenario studies were conducted.

Sensitivity Study Results

To understand the effect of each key variable on the local capacity surplus/deficits, sensitivity cases were run for *each* variable described in Chapter 4. The results report the bottom-line surplus/deficit of total resources in the local area compared to the adjusted LCR for the area. A positive value identifies a surplus, meaning that resources exceed requirements, and there is no local capacity concern. A negative value indicates an insufficient amount of capacity to satisfy reliability standards in that area for the given set of assumptions and requirements. Compared to the baseline results, some variables increase the projected amount of surplus/deficit, while others decrease the amount. There may be differences in impact within the set of local areas. For example, some variables may have very little impact in the San Diego local area. In general, the following variables/sensitivities have a positive impact by 2025 and improve the outlook of local capacity surplus/deficits:

- Mid-AAEE as an LCR planning assumption
- Demand response full capability
- *2015 IEPR* as the source for base demand forecast
- Storage high development pattern
- Demand response moderate capability
- Storage moderate development pattern

The following variables/sensitivities have a negative impact by 2025 and worsen the outlook of local capacity surplus/deficits:

- Cogeneration transition to wholesale generators
- AAEE realization rate reduction
- Higher base demand forecast
- Peak shift induced by BTM rooftop PV capacity

Table 17 presents the local capacity surplus/deficit 2025, and **Table 18** presents the difference in surplus/deficit for the sensitivity cases versus the baseline case for 2025. The local areas reported are the various geographic regions in Southern California affected by the retirement of San Onofre and within which various resource additions and transmission system upgrades area are addressing the loss of San Onofre capacity and the loss of a substantial amount of fossil-fueled OTC capacity. The results show that for the combined L.A. Basin/San Diego area, the *2015 IEPR* demand forecast has the greatest impact on local capacity surplus/deficits in 2025 and increases local capacity by 4,457 MW. The deficit of 400 MW in the baseline case is eliminated, resulting in a surplus of 4,057 MW. On the other extreme, the results show that the higher demand sensitivity of 3.5 percent higher growth in demand by 2021 and 5.5 percent greater demand by 2025. These results have the greatest impact on local capacity deficits and decreases local capacity by 1,626 MW. The deficit of 400 MW in the baseline case grows to a deficit of 2,026 MW. The results for the other geographic areas show a similar pattern for these two sensitivities.

Table 18 shows that the sensitivities can produce a wide range of impacts in 2025. The sensitivity cases using *2015 IEPR* peak demand and higher demand growth define the envelope of higher and lower bounds, respectively. Sensitivities like mid-case AAEE projections and various higher levels of demand response and storage all generally increase surpluses in local capacity areas or subareas. At the other end of the spectrum, the sensitivity cases using reduced transition of cogeneration QFs to wholesale generators, energy efficiency reduction, and peak shift worse the surplus/deficit outlook for local capacity areas or subareas. In some instances, a sensitivity case can have a large impact in a specific area but not in others. The peak shift sensitivity is a good example in having much larger proportional impacts in SD-IV than elsewhere.

Table 17: 2025 Resource Surplus/Deficit by Area (MW)

Variable	L.A. Basin/SD	L.A. Basin	Western L.A. Subarea	Eastern L.A. Subarea	SD-IV	San Diego Subarea
2015 Demand	4,057	3,379	1,277	2,102	730	678
Mid-AAEE	506	494	(338)	832	64	12
Demand Response Full	279	482	(466)	639	(151)	(203)
Storage High	(6)	117	(523)	639	(70)	(123)
Demand Response Moderate	(61)	143	(651)	639	(151)	(203)
Storage Moderate	(216)	(40)	(679)	639	(123)	(175)
Baseline	(400)	(197)	(836)	639	(151)	(203)
Cogen	(600)	(319)	(903)	584	(229)	(281)
Peak Shift	(878)	(575)	(1,055)	480	(702)	(303)
AAEE Reduction	(1,026)	(662)	(1,178)	515	(312)	(364)
Higher Demand	(2,026)	(1,501)	(1,607)	106	(473)	(525)

Source: California Energy Commission staff

Table 18: 2025 Change in Resource Surplus/Deficit From Baseline Case (MW)

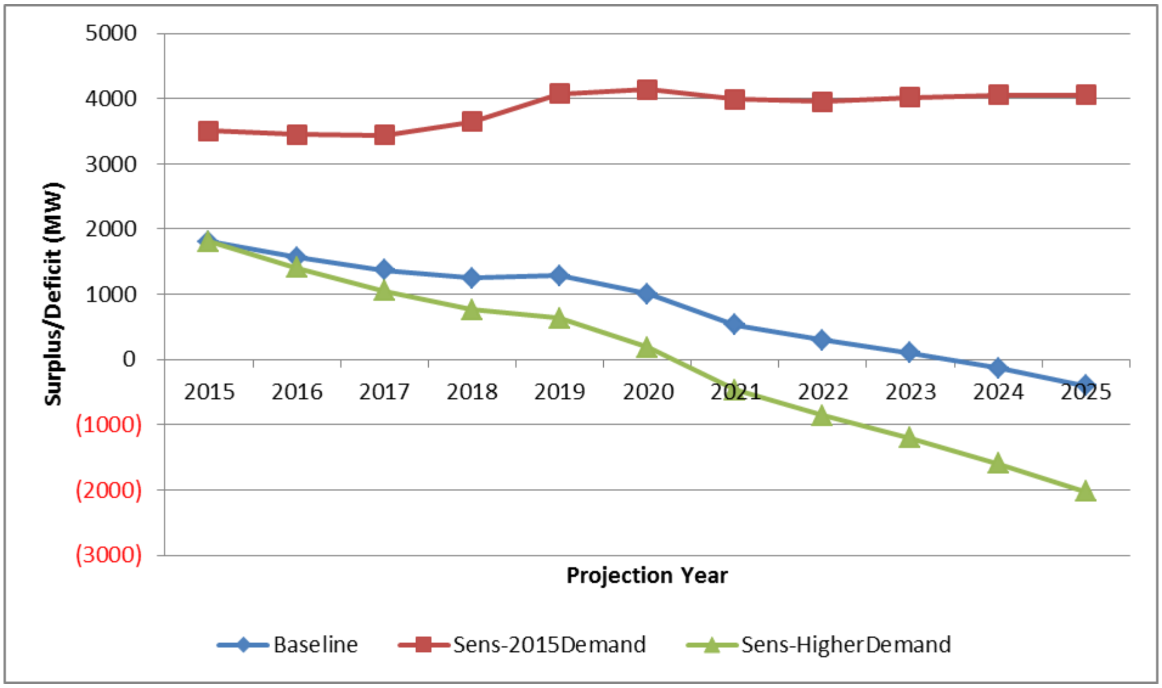
Variable	L.A. Basin/SD	L.A. Basin	Western L.A. Subarea	Eastern L.A. Subarea	SD-IV	San Diego Subarea
2015 Demand	4,457	3,576	2,113	1,463	881	881
Mid-AAEE	906	691	498	193	215	215
Demand Response Full	679	679	370	-	-	-
Storage High	394	313	313	-	81	81
Demand Response Moderate	339	339	185	-	-	-
Storage Moderate	184	157	157	-	28	28
Baseline	-	-	-	-	-	-
Cogen	(200)	(122)	(67)	(56)	(78)	(78)
Peak Shift	(478)	(378)	(219)	(159)	(550)	(100)
AAEE Reduction	(626)	(466)	(342)	(124)	(160)	(160)
Higher Demand	(1,626)	(1,304)	(771)	(534)	(322)	(322)

Source: California Energy Commission staff

Figure 6 (for the combined L.A. Basin/San Diego area) presents the annual results of the sensitivities that are the boundary of the envelope containing all sensitivities. The peak demand forecast from the *2015 IEPR* provides the greatest improvement, while the Higher Demand sensitivity case sets the worst outcome for this area. **Figure 6** requires explanation, since the two boundary cases are not directly comparable. First, the Higher Demand sensitivity case adjusts the baseline peak demand forecasts from the *2014 IEPR Update.* This was the demand forecast that was the starting point for the California ISO studies of local capacity requirements in the 2015/16 TPP effort. The Higher Demand sensitivity case (a gradual increase in the baseline peak demand forecast) should, and **Figure 6** confirms, have a gradual reduction of the surplus. This sensitivity accelerates the year the deficit appears to 2021 from 2024. Second, the *2015 IEPR* peak demand sensitivity is a different analytic effort with numerous factors making it different from the *2014 IEPR Update* baseline peak demand forecast. Among these are different economic and demographic drivers, more recent data on historical BTM PV penetration, more recent actual electricity usage data (peak and energy sales), and a redefinition of the SCE Transmission Access Charge area. As a result, the starting point in 2015 for the *2015 IEPR* sensitivity case is much higher than either of the other two cases in **Figure 6,** and the margin grows through time.

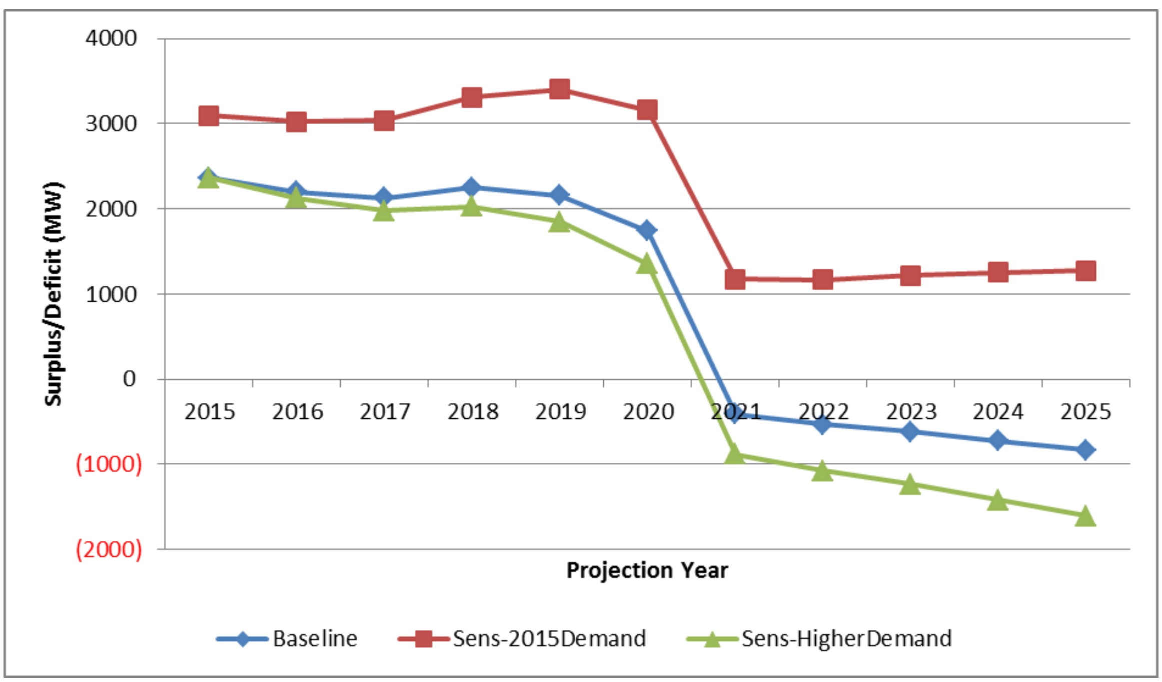
Figure 7 for the Western L.A. subarea presents the annual results for the two sensitivities that provide the bounding cases for local capacity surpluses or deficits. The same two sensitivity cases provide the bounds for Western L.A. subarea as for the composite L.A. Basin-San Diego subarea, but the shape of the surplus/deficit is different. The large OTC capacity retirement at the end of 2020 induces a major reduction in the capacity surplus at that point in time. The Higher Demand sensitivity case worsens the deficits compared to the baseline but does not accelerate the year in which the deficit appears. The *2015 IEPR* demand sensitivity case eliminates the deficits.

Figure 6: Bounding Sensitivity Cases for the L.A. Basin/San Diego Subarea (MW)



Source: California Energy Commission staff

Figure 7: Bounding Sensitivity Case for the Western L.A. Subarea (MW)



Source: California Energy Commission staff

Design of Scenarios

The sensitivity assessment described above shows how the LCAAT tool responds to alternative inputs. This discussion and the annual results in Appendix C could be interpreted to mean that all is well once the California ISO uses the *2015 IEPR* peak demand forecast as the basis for its 2016-17 studies. However, some controversy surrounds the adopted *2015 IEPR* peak demand forecasts regarding the consequences of the high levels of BTM PV capacity that are in the Energy Commission demand forecasts. The *2015 IEPR* reports that data and methodological improvements are needed.[54] The peak shift sensitivity case attempted to illustrate two aspects of this issue.

Two alternative scenarios were designed to provide a sense of the range around the baseline results—surplus/deficit of resources relative to requirements—when *multiple* variables are modified from the baseline values to an alternative. Many combinations of variables might be tried, but the two identified here provide a useful understanding of the spread that can be projected. Each element of a future scenario that combines the impact of multiple variables can move the surplus/deficit in the same direction or can offset one another. For example, higher demand growth can be mostly offset by using the mid-case AAEE projections rather than the low-mid case.

Table 19 outlines the general approach used to design the scenarios. The High Surplus scenario starts by using the lower *2015 IEPR* peak demand forecast rather than the *2014 IEPR Update* peak demand forecasts used by the California ISO in its 2015-16 TPP local capacity area studies. Adjustments to this forecast follow the direction provided in the *2015 IEPR* regarding the BTM PV capacity-induced peak load shifts. To this alternative peak demand forecast is added some load growth by reducing the growth in BTM PV in 2022 through 2025 once the federal investment tax credit expires. Finally, this future demand is adjusted upward by adding the incremental load described in the peak shift sensitivity. The *Low Surplus* scenario increases peak load relative to the *2014 IEPR Update* baseline by assuming a slightly higher rate of load growth in each year, cumulatively representing 5 percent increase by 2025. Peak load is further increased by assuming that AAEE peak savings are lower as described in the AAEE sensitivity case. Finally, retirements are slightly higher than in the baseline to reflect retirement of cogeneration facilities at age 35, rather than age 40.

The final row of **Table 19** provides a simplified description of the resource surplus/deficit compared to local capacity requirements in the L.A. Basin for 2025. The two alternative scenarios are roughly symmetric around the baseline results.

In the next section, the results of several scenarios are presented. The Energy Commission staff designed these two scenarios to have significant levels of change.

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54 Energy Commission's *2015 IEPR*, p. 145. http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-01/TN212017_20160629T154354_2015_Integrated_Energy_Policy_Report_Small_File_Size.pdf.

Other scenarios, defined by variables with more moderate impact, could be easily defined that would have results closer to the baseline.

Table 19: Variable Values for Alternative Scenarios

Variable	Scenarios: High Surplus	Scenarios: Baseline	Scenarios: Low Surplus
Demand-Side			
Load Forecast Source	*2015 IEPR*	Baseline	Baseline
High Load Forecast	BTM PV growth reduced in years after ITC expires	Baseline	5% Higher by 2025
AAEE Peak Savings/Participation	Baseline	Baseline	0.6
Peak Shift Impact on Load	Incremental load due to delayed peak hour	Baseline	Baseline
Supply-Side			
Demand Response Effectiveness	Baseline	Baseline	Baseline
Storage (IFM Only)	Baseline	Baseline	Baseline
Cogen Transition From QFs to Wholesale	Baseline	Baseline	35-Year
RPS Portfolio	Baseline	Baseline	Baseline
Peak Shift Impact on Solar Renewables	Reduce BTM PV Output	Baseline	Baseline
Impact on LA Basin Surplus/Deficit in Year 2025	Improve Surplus/Deficit by 2200 MW	N/A	Worsen Surplus/Deficit by 2000 MW

Source: California Energy Commission staff

Scenario Study Results

The LCAAT was exercised using scenarios constructed from the set of baseline and alternative variable inputs outlined in **Table 19.** Results for each scenario were copied to an output workbook housing all sensitivity and scenario results from which figures comparing one scenario to another could be easily prepared. Appendix C provides numeric results.

Figures 8-12 provide the results for five areas that are key to understanding the local capacity consequences of various future conditions, both for baseline and for alternative sets of assumptions. Each of these five figures reports the bottom-line surplus/deficit of total resources in the area less the local requirements for the area. A positive value identifies a surplus, meaning that resources exceed requirements and there is no local capacity concern. A negative value indicates an insufficient amount of capacity to satisfy reliability standards in that area for the given set of assumptions and requirements.

Figure 8 and **Figure 9** for the composite L.A. Basin-San Diego subarea and L.A. Basin by itself, respectively, have the same general shape. There is a substantial surplus in the early years, but the surplus gradually decreases through time. The baseline surplus/deficit balance reaches a deficit condition at the end of the forecast period. The more pessimistic case reaches a deficit much earlier. The High Surplus case never reaches a deficit. **Figure 10** and **Figure 11** for West L.A. subarea and SD-IV, respectively, also share a similar shape, with a substantial surplus through 2020, and then the loss of fossil-fueled OTC capacity at the end of 2020 causes a precipitous drop in the quantity of resource surplus. **Figure 12** for the San Diego subarea has an entirely different shape. In each scenario, the level of surplus or deficit is relatively uniform through the entire projection period. In two scenarios, there are many years in which there is a deficit. In the High Surplus scenario, there is always a surplus.

Implications for Once-Through Cooling Policy Compliance

In all cases, the OTC facilities located within an area are assumed to retire on or before the OTC policy compliance dates, and the replacement capacity authorized by the CPUC comes on-line just in time to substitute for some of the retired OTC capacity. What does LCAAT have to say about the consequences if OTC replacement capacity is delayed?

The San Diego subarea is scheduled to lose its only OTC capacity with the closure of Encina at the end of 2017. Assuming that the Carlsbad facility is brought on-line by the end of 2017, the San Diego subarea shows a capacity surplus in 2017 changing to a capacity deficit in 2018. The simple explanation is that the 960 MW Encina is replaced by the 500 MW Carlsbad facility, and a set of preferred resources and storage is not fully implemented until further out in time. However, in all scenarios, if Carlsbad is delayed beyond a late 2017 to early 2018 on-line date, then the San Diego subarea deficit would be much worse. This delay suggests that the SWRCB defer the compliance date for Encina to match the expected start date of Carlsbad. An OTC deferral request would be a logical response to an expected delay in the start date for Carlsbad since little or no investments are required to keep Encina running for another year or two. There is, of course, an environmental cost to continuing to operate Encina since the basis of the OTC policy—impingement and entrainment of sea life in the water intake structures of the facility—would continue as long as the facility was operational. The SWRCB has broadly outlined how it would consider an OTC compliance date deferral request,[55] and the Energy Commission developed a report providing further

55 SWRCB, Testimony of Jon Bishop, August 20, 2014, in Energy Commission *2014 IEPR Update* workshop, see transcript pp. 152-159, http://www.energy.ca.gov/2014_energypolicy/documents/2014-08-20_workshop/2014-08-20_iepr_transcript.pdf.

details[56] for consideration at the forthcoming *2016 IEPR Update* workshop, scheduled for August 29, 2016.[57]

From the SD-IV perspective, **Figure 11** shows a much different pattern. All cases have a large surplus until 2021 when the LCR for this LCA increases dramatically to address thermal overloads in the L.A. Basin. In the baseline and Pessimistic Scenario cases, deficits occur in 2021. Even in the High Surplus scenario, the margin of surplus shrinks dramatically in 2021 and becomes a deficit by 2025. A delay in the on-line date of Carlsbad would not create any concerns in this LCA unless the delay extended to 2020 or 2021.

Finally**, Figure 10** for the West L.A. subarea shows deficits beginning in 2021 for the baseline and Pessimistic cases. Even though the margin of surplus in the High Surplus case remains positive in all years, it diminishes steadily. All of these cases assume that the cohort of OTC facilities in the West L.A. subarea retires on or before the December 31, 2020, compliance dates established in the OTC policy, and that the generating facilities and PPAs approved by the CPUC are implemented on the schedules proposed. Delays in any of the larger elements of this replacement capacity (640 MW of Alamitos replacement capacity, 640 MW of Huntington Beach replacement capacity) would likely create reliability problems. There is insufficient "slack" in the combined resource capacity to allow for any slippage in new resource development. Deferral of OTC compliance might be an appropriate response if there was merely an expected delay in the on-line date of one of these replacement generating facilities. If it appeared that one of them was seriously threatened, then the small deficits in the baseline projections suggest that a new resource addition should be considered.

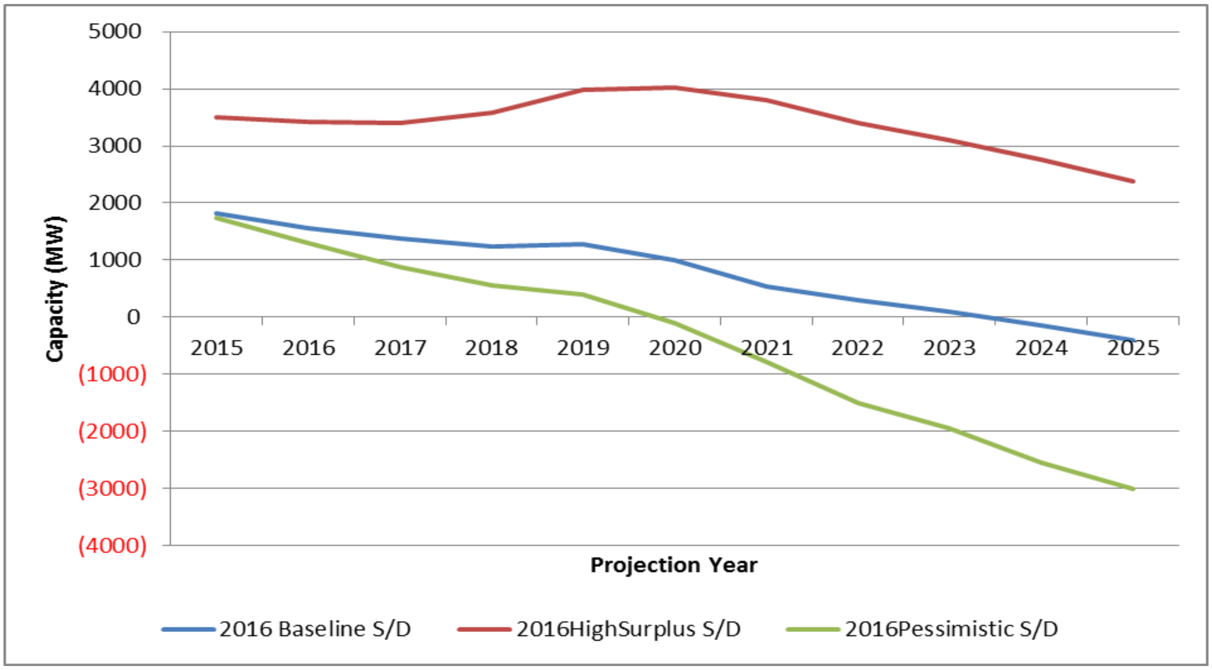
The annual surplus/deficit projections that the LCAAT makes ease improved electricity system planning. The highly intensive power flow modeling studies that the California ISO undertakes in each TPP cycle cannot be conducted for all years and for all plausible combinations of input variable assumptions. LCAAT provides a screening function by identifying specific years and sets of inputs that should be investigated using in-depth techniques. Knowledge of the various surplus/deficit patterns in the baseline and alternative cases is highly useful because it allows the standard electricity planning and procurement authorization processes to be used rather than having to create alternative processes in response to an emergency. Although the state's GHG emission reduction targets, and the mechanism to achieve them, are critically important, continuing to assure electricity system reliability is equally important. Decision makers should pay

56 Jaske, Michael R. and Lana Wong. 2016. *Mitigation Options for Contingencies Threatening Southern California Electric Reliability*. California Energy Commission. Publication Number: CEC-200-2016-010. http://docketpublic.energy.ca.gov/PublicDocuments/16-IEPR-06/TN212836_20160818T131005_Staff_Report_Mitigation_Options_for_Contingencies_Threatening_S.pdf.

57 Energy Commission, *2016 IEPR Update*, Notice of Lead Commissioner Workshop for August 29, 2016.

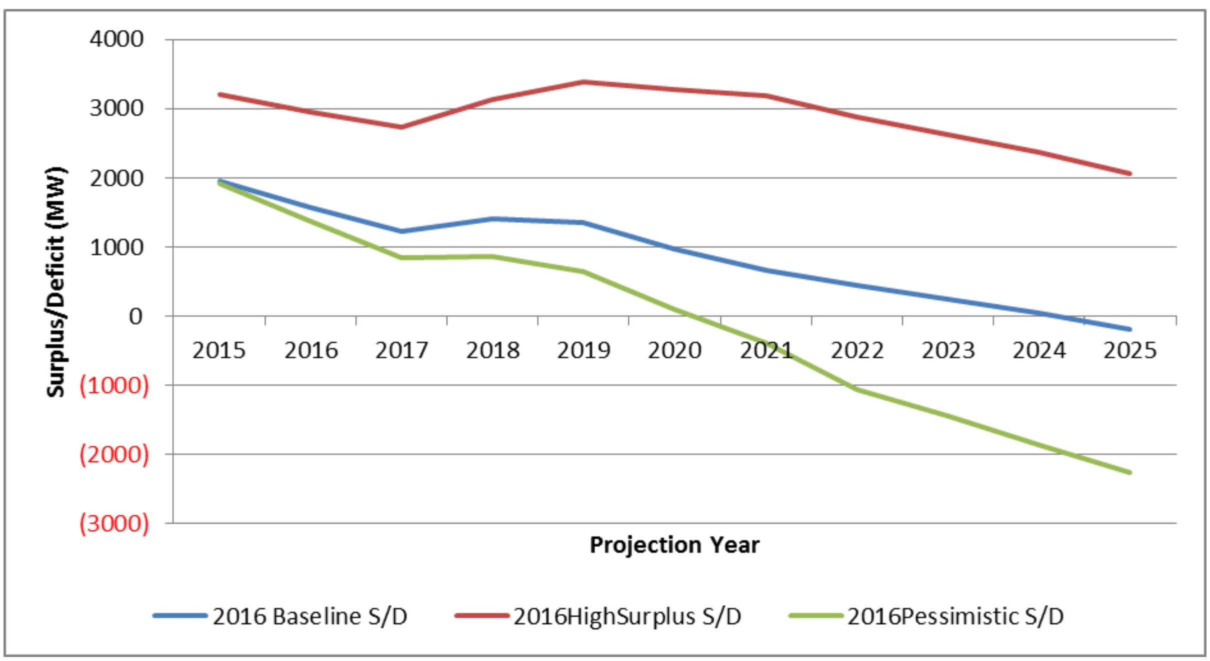
attention to analyses for intermediate years and not focus exclusively on the tenth forward year or 2030.

Figure 8: Resource Surplus/Deficit for Composite L.A. Basin-San Diego Subarea



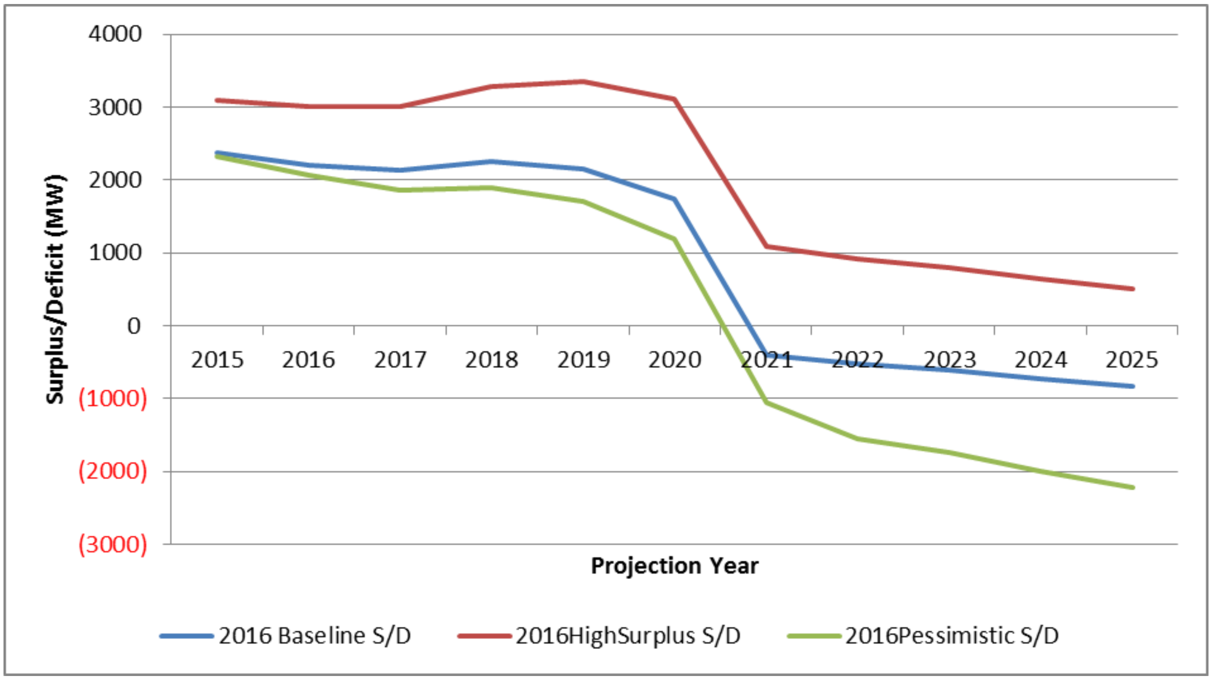
Source: California Energy Commission staff

Figure 9: Resource Surplus/Deficit for L.A. Basin Local Capacity Area



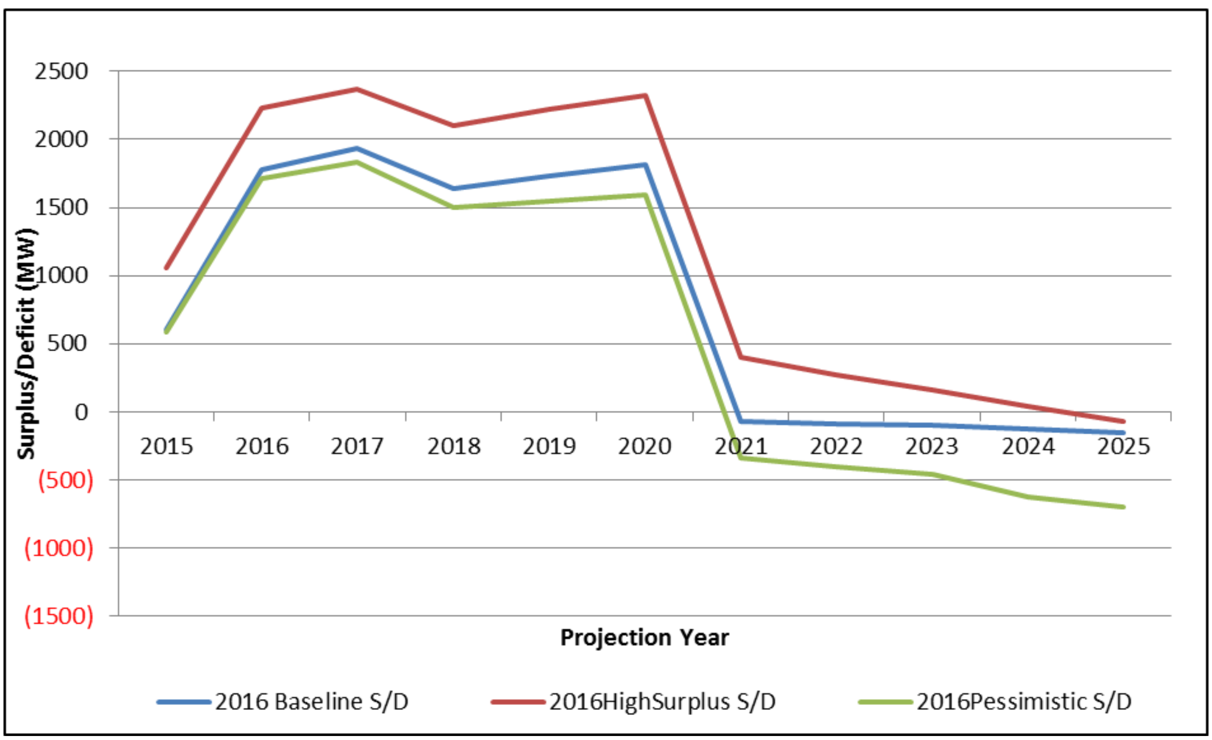
Source: California Energy Commission staff

Figure 10: Resource Surplus/Deficit for West Los Angeles Subarea



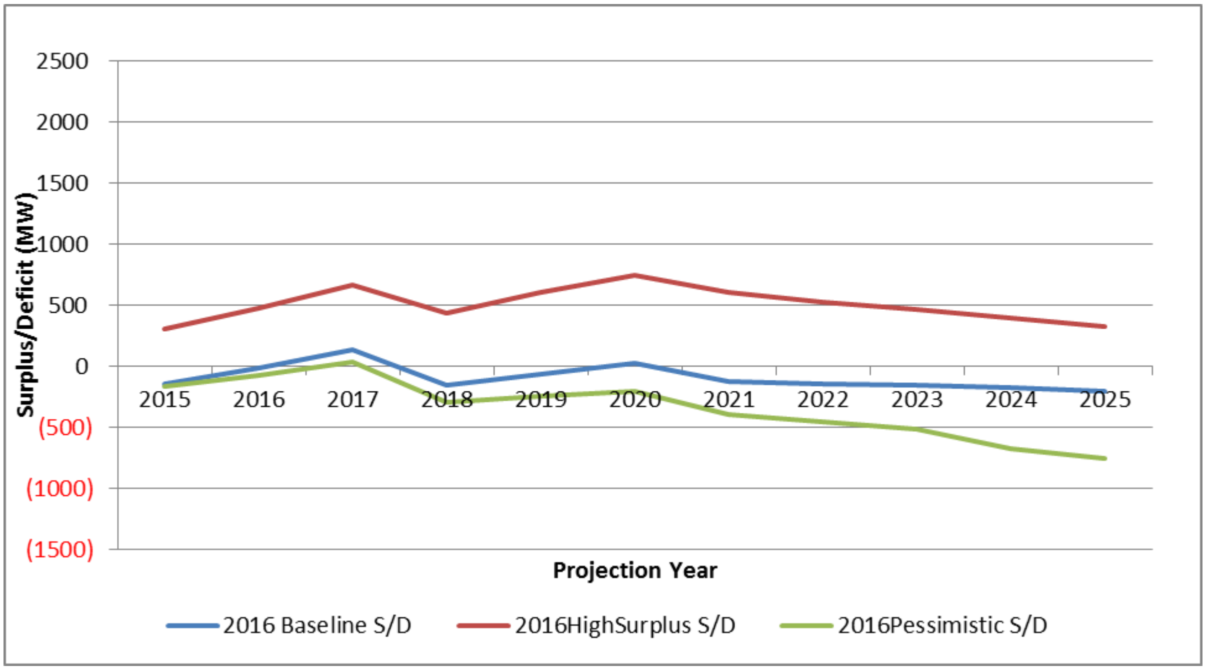
Source: California Energy Commission staff

Figure 11: Resource Surplus/Deficit for San Diego – Imperial Valley Area



Source: California Energy Commission staff

Figure 12: Resource Surplus/Deficit for San Diego Subarea



Source: California Energy Commission staff

CHAPTER 6: Conclusions and Findings

Conclusions

Using the LCAAT to assess baseline assumptions for intermediate years not explicitly studied by the California ISO shows baseline deficits in all portions of Southern California by 2025. The 2025 baseline results are consistent with California ISO studies documented in the *2015-2016 Transmission Plan* adopted by the California ISO in March 2016. The deficits in 2021 are also consistent with California ISO studies from that cycle of studies, most of which were published in the adopted transmission plan. Surplus/deficit results for other years are not revealed in the California ISO's published local capacity studies since the California ISO studied only 2021 and 2025. Many uncertainties exist in the variables that constitute the planning assumptions for both the LCAAT and the LCR studies prepared by the California ISO. To evaluate the consequences of these uncertainties, the LCAAT was used to assess 10 single-variable sensitivities for eight variables and developed two alternative scenarios with differences from the baseline set of assumptions. Not surprisingly, sensitivities and scenarios in which load was reduced or resources increased diminished the level of deficit and sometimes eliminated them. Correspondingly, sensitivities and scenarios in which either load was increased or resources were decreased exacerbated the shortfalls or reduced the surpluses found using the baseline set of assumptions. Scenarios in **Figures 8-12** provide some understanding of the range for 2018 to 2025 that can be either a surplus or a deficit regardless of the results using baseline assumptions.

The alternative assumptions evaluated as sensitivities and as scenarios are not considered extreme, but the compounding effects over time imply one or more of the following:

- Lack of data about differences between real-world activities and planning assumptions.
- Inattention to data revealing issues with the realization of such assumptions.
- Adherence to use of planning goals regardless of what contrary monitoring data might reveal.
- Unresolved disputes about interpreting recent monitoring data as either "near-term growing pains" that will be overcome later versus clear evidence that planning assumptions are overly optimistic.

The hope is that the planning processes of the agencies would detect and resolve these issues and not allow them to compound through time.

Development of the LCAAT and the use to identify the consequences of uncertain input assumptions provide insights that could, in principle, be determined through the more in-depth studies using power flow modeling. In reality, these insights cannot be gained from the studies conducted and published by the California ISO because the California ISO does not have the resources to prepare many studies. Such power flow modeling efforts are too resource-intensive to be exercised for the multiplicity of alternative input assumptions combinations that are reasonable future conditions. *LCAAT is designed to complement these power flow modeling studies, not replace them.* In fact, LCAAT is specifically designed to use the results of these resource-intensive studies to the greatest extent possible. California ISO study results through the LCTA and TPP processes have been used as inputs into the LCAAT. The proper role of the LCAAT is as a screening tool to identify alternative combinations of future assumptions that reveal conditions that should be studied in-depth using power flow and stability modeling.

Preliminary Findings

The following preliminary findings derive from the development and exercise of LCAAT as described earlier in this report. These findings merit further review and discussion:

- Deficits using baseline assumptions in the West L.A. subarea and two San Diego areas are a concern, but not a cause for alarm. North American Electric Reliability Corporation/Western Electricity Coordinating Council planning standards require that overlapping contingencies under adverse load conditions be studied. Unfortunately, alternative assumptions can worsen or improve these results. Decision-makers will have to rely upon judgment in deciding whether or how to act, since state-of-the-art planning does not allow assessments in a probabilistic framework to guide whether the combination of factors leading to deficits is sufficiently likely that action should be taken right now.
- Monitoring actual savings from demand-side programs designed to achieve energy and peak load reductions is critical to assuring reliability. The scale of future savings expected from such programs in Energy Commission, CPUC, and California ISO electricity planning studies is so large that credible degrees of failure can lead to resource shortfalls large enough to affect local reliability in one or more areas. Results of such monitoring need to be shared broadly among the energy agencies, and results should be folded into planning assumptions for planning studies as quickly as possible. Treating goals as credible planning assumptions *may threaten* future reliability and *will limit* resource choices as the time horizon to effectuate resource additions shrinks.
- As it did in the 2015-16 TPP, the California ISO should study 2021 intensively with several alternative sets of input assumptions drawn from LCAAT scenarios. The LCAAT baseline results show deficits, and credible alternative scenarios reveal such deficits can be much worse. The time horizon between now and summer 2021 begins to constrain options for new resource development. Delays

in undertaking such studies would further limit the range of options that could provide sufficient resources, either demand-side or supply-side, to assure that LCRs are satisfied throughout the L.A. Basin.

- The CPUC should take three actions:

  1. Include in its Integrated Resource Plan (R.16-02-007) rulemaking an explicit focus on LCRs. Further, the CPUC should not assume that such requirements in the intermediate period 5-8 years forward have been satisfied through decisions in the 2012 LTPP rulemaking and the procurement activities authorized by D.14-03-004. The LCAAT results suggest that an assessment for future years should be part of each LTPP cycle unless a convincing analytic determination shows intermediate years are fully satisfied using a credible package of planning assumptions.

  2. Modify its examination of alternative methods for determining capacity value for solar and wind renewables to address the consequences of peak demand shifting to later times of the day. Although the ELCC approach should "automatically" determine capacity value at the peak hour with fewest resources, the inputs into the ELCC method need to properly reflect future conditions and not merely replicate the historical load patterns. Peak shift induced by rapid increases in BTM solar PV capacity additions are not reflected in any historical record. An explicit effort to develop a credible range of load shapes that reflect BTM solar PV and other demand-side programmatic impacts is vital to the successful implementation of the ELCC approach. Modifications to the existing exceedance method are more readily accomplished.

  3. Energy efficiency evaluation, measurement, and verification results need to be completed and released quickly with as little lag between the program year and the release of evaluated results as possible. Evaluated peak savings from 2013 program year efforts have not been released as of this assessment. Shortfalls in actual peak savings relative to planned peak savings that were found in evaluations of 2010-2012 program year studies are disturbing. Lack of current monitoring results, especially for peak savings, call into question the use of AAEE savings projections, which rely exclusively on peak savings rather than annual energy savings.

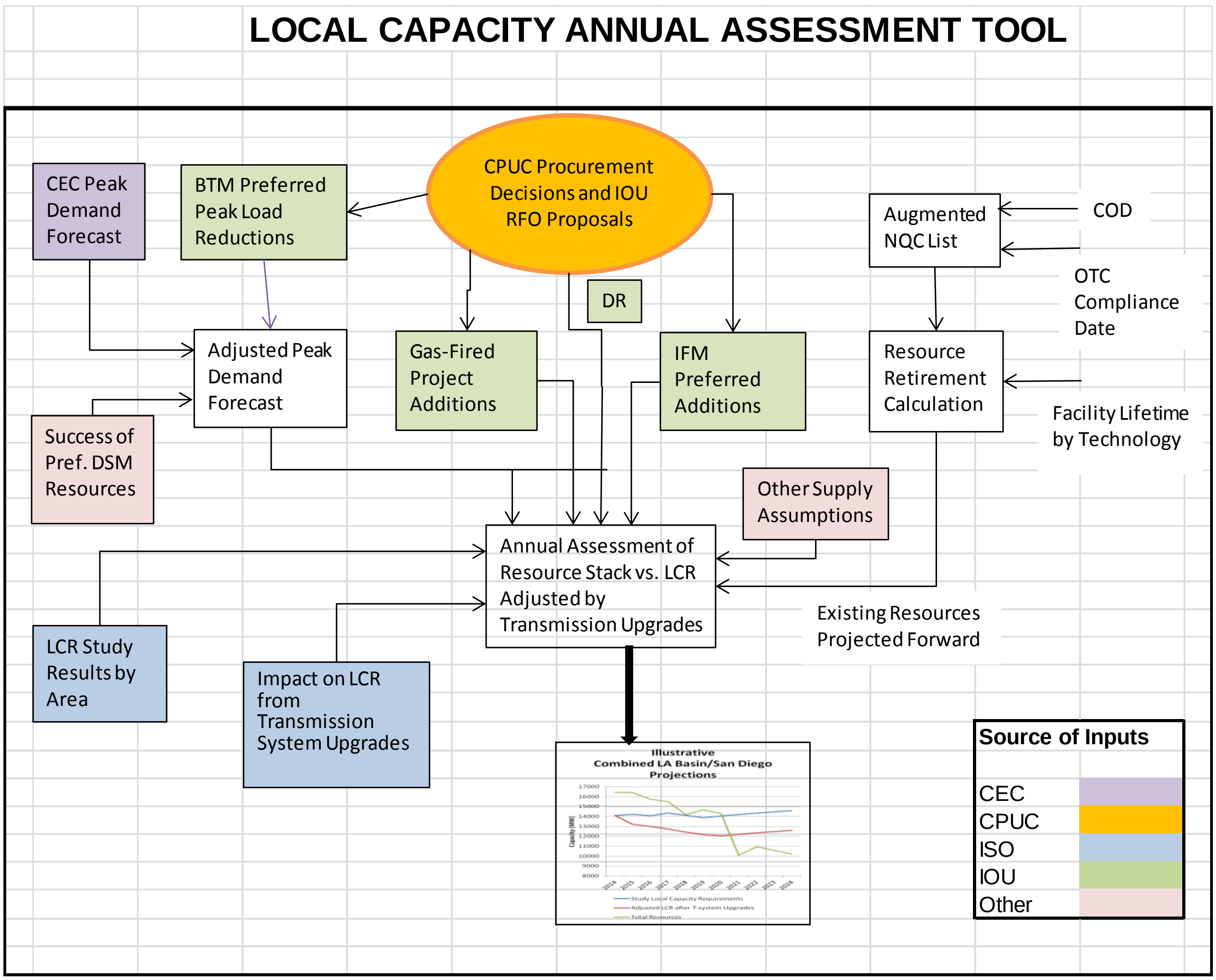
Acronyms and Abbreviations

Acronym/Abbreviation	Original Term
2014 IEPR Update	*2014 Integrated Energy Policy Report Update*
2015 IEPR	*2015 Integrated Energy Policy Report*
2016 IEPR Update	*2016 Integrated Energy Policy Report Update*
AAEE	Additional achievable energy efficiency
ARB	California Air Resources Board
BTM	Behind-the-meter
California ISO	California Independent System Operator
CPUC	California Public Utilities Commission
CPUC/ED	California Public Utilities Commission's Energy Division
CHP	Combined heat and power
DG	Distributed generation
ELCC	Effective load-carrying capability
Energy Commission	California Energy Commission
GHG	Greenhouse gas
HE	Hour ending
IEPR	*Integrated Energy Policy Report*
IOU	Investor-owned utility
L.A. Basin	Los Angeles Basin
LCA	Local capacity area
LCAAT	Local capacity annual assessment tool
LCR	Load capacity requirement
LCTA	Local Capacity Technical Analysis
LTPP	Long-Term Procurement Planning
MW	Megawatt
OTC	Once-through cooling

Acronym/Abbreviation	Original Term
PPA	Power purchase agreement
PURPA	Public Utilities Regulatory Policies Act of 1978
PV	Photovoltaic
QC	Qualifying capacity
QF	Qualifying facility
RETI	Renewable Energy Transmission Initiative
RFO	Request for offer
RPS	Renewables Portfolio Standard
San Onofre	San Onofre Nuclear Generating Station
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SD-IV	San Diego-Imperial Valley
SCRP	Southern California Reliability Project
SWRCB	State Water Resources Control Board
TPP	Transmission Planning Process

APPENDIX A: Local Capacity Annual Assessment Tool Schematic

Figure A-1: Local Capacity Annual Assessment Tool



Source: California Energy Commission staff, 2014

APPENDIX B:
Baseline Local Capacity Annual Assessment Tool Results by Area

Table B-1: Baseline Results for Consolidated L.A. Basin/San Diego Subarea

	Variables (Summer Peak MW)	Source	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
LA Basin/San Diego Subarea													
	Base Load Forecast	2014 IEPR Up	26530	26790	27134	27485	27831	28171	28479	28773	29051	29307	29567
less	Load Forecast Adjustment (positive is a decrease)		0	0	0	0	0	0	0	0	0	0	0
less	AAEE	2014 IEPR Up	161	325	490	606	740	862	983	1108	1255	1402	1565
less	Preferred EE	SCE RFO/SD?	0	5	24	102	127	138	144	137	129	116	104
less	Preferred BTM Energy Storage	SCE RFO/SD?	0	0	25	163	195	198	196	198	198	198	198
less	Preferred BTM DG	SCE RFO/SD?	0	0	11	40	40	40	40	40	40	40	40
=	Managed Load Forecast		26368	26460	26585	26574	26730	26933	27117	27291	27430	27552	27660
	Gross Local Capacity Requirements	2014/15 TPP	12601	12564	13356	13745	13666	13815	12692	13038	13406	13774	14158
less	T-system Upgrade Impacts		(240)	(240)	(840)	(1086)	(846)	(846)	(1146)	(1146)	(1146)	(1146)	(1146)
less	LCR Change from Demand Adjustments		(161)	(330)	(549)	(911)	(1101)	(1238)	(1362)	(1482)	(1621)	(1755)	(1907)
=	Adjusted LCR Base		12200	11994	11967	11748	11719	11731	10183	10410	10639	10873	11105
less	OTC Non Nuclear	ScenTool	5117	4782	4676	3818	3818	2238	0	0	0	0	0
less	OTC Nuclear	ScenTool	0	0	0	0	0	0	0	0	0	0	0
less	Hydro	ScenTool	351	351	351	351	351	351	351	351	351	351	351
less	Solar	ScenTool	59	59	59	59	59	59	59	59	59	59	59
less	Wind	ScenTool	64	64	64	64	64	64	64	64	62	62	60
less	Geothermal	ScenTool	0	0	0	0	0	0	0	0	0	0	0
less	Biomass	ScenTool	117	117	117	117	117	117	117	117	117	117	114
less	Cogeneration	ScenTool	847	847	847	847	847	866	866	837	837	837	806
less	Pump	ScenTool	0	0	0	0	0	0	0	0	0	0	0
less	Non OTC Peaker	ScenTool	1711	1780	1667	1667	1667	1667	1667	1667	1667	1667	1667
less	Non OTC Thermal	ScenTool	5530	5210	4890	4890	4890	4890	4890	4890	4890	4890	4890
less	Various and Unknown	ScenTool	34	34	34	34	34	34	34	34	34	34	34
less	Incr. Peaker Additions	SCE RFO	0	0	308	808	808	808	906	906	906	906	906
less	Incr. Thermal Additions	SCE RFO	0	0	0	0	0	1280	1280	1280	1280	1280	1280
less	Incr. RPS Calc - Renew	14/15 Port	0	0	0	0	0	0	0	0	0	0	0
less	Incr. RPS Calc - DG	14/15 Port	0	128	139	145	151	159	175	196	234	234	234
less	Storage Additions	SCE RFO/D14-03-	0	0	0	0	0	0	100	100	100	100	100
less	DR Program Capability/ Preferred DR		183	186	189	197	200	203	206	203	203	203	203
=	Total Resources Base		14013	13557	13340	12996	13005	12736	10714	10704	10741	10740	10705
=	Resource Need (Surplus/Deficit) Base		1813	1563	1373	1247	1286	1005	531	294	102	(132)	(400)

Source: California Energy Commission staff

Table B-2: Baseline Results for L.A. Basin Area

	Variables (Summer Peak MW)	Source	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
LA Basin													
	Base Load Forecast	2014 IEPR Up	21206	21418	21681	21956	22229	22517	22781	23031	23273	23493	23717
less	Load Forecast Adjustment (positive is a decrease)		0	0	0	0	0	0	0	0	0	0	0
less	AAEE	2014 IEPR Up	123	247	372	460	559	649	737	828	936	1044	1164
less	Preferred EE	SCE RFO	0	5	24	99	120	128	130	120	109	98	88
less	Preferred BTM Energy Storage	SCE RFO	0	0	25	163	169	172	170	172	172	172	172
less	Preferred BTM DG	SCE RFO	0	0	11	40	40	40	40	40	40	40	40
=	Managed Load Forecast		21083	21166	21250	21194	21341	21527	21703	21871	22017	22139	22252
	Gross Local Capacity Requirements		9460	9374	9985	10258	10203	10378	9062	9352	9658	9964	10283
less	T-system Upgrade Impacts		(240)	(240)	(640)	(740)	(500)	(500)	(800)	(800)	(800)	(800)	(800)
less	LCR Change from Demand Adjustments		(123)	(252)	(431)	(762)	(888)	(989)	(1078)	(1160)	(1256)	(1354)	(1464)
=	Adjusted LCR Base		9097	8882	8914	8756	8814	8889	7184	7392	7601	7811	8019
	OTC Non Nuclear	ScenTool	4153	3818	3818	3818	3818	2238	0	0	0	0	0
plus	OTC Nuclear	ScenTool	0	0	0	0	0	0	0	0	0	0	0
plus	Hydro	ScenTool	307	307	308	308	308	308	308	308	308	308	308
plus	Solar	ScenTool	22	22	22	22	22	22	22	22	22	22	22
plus	Wind	ScenTool	59	59	59	59	59	59	59	59	57	57	55
plus	Geothermal	ScenTool	0	0	0	0	0	0	0	0	0	0	0
plus	Biomass	ScenTool	97	97	97	97	97	97	97	97	97	97	97
plus	Cogeneration	ScenTool	712	712	712	712	712	712	712	683	683	683	652
plus	Pump	ScenTool	0	0	0	0	0	0	0	0	0	0	0
plus	Non OTC Peaker	ScenTool	1199	1154	1154	1154	1154	1154	1154	1154	1154	1154	1154
plus	Non OTC Thermal	ScenTool	4312	3992	3672	3672	3672	3672	3672	3672	3672	3672	3672
plus	Various and Unknown	ScenTool	33	33	33	33	33	33	33	33	33	33	33
plus	Incr. Peaker Additions	SCE RFO	0	0	0	0	0	0	98	98	98	98	98
plus	Incr. Thermal Additions	SCE RFO	0	0	0	0	0	1280	1280	1280	1280	1280	1280
plus	Incr. RPS Calc - Renew	14/15 Port	0	0	0	0	0	0	0	0	0	0	0
plus	Incr. RPS Calc - DG	14/15 Port	0	103	103	108	110	114	123	144	170	170	170
plus	Storage Additions	SCE RFO	0	0	0	0	0	0	100	100	100	100	100
plus	DR Program/Preferred DRCapability		164	167	169	177	180	182	185	182	182	182	182
=	Total Resources Base		11056	10463	10145	10158	10163	9870	7841	7830	7855	7855	7822
=	Resource Need (Surplus/Deficit) Base		1959	1580	1232	1401	1349	981	656	438	253	44	(197)

Source: California Energy Commission staff

Table B-3: Baseline Results for West Los Angeles Subarea

	Variables (Summer Peak MW)	Source	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
West LA Basin Only (subset of LA Basin)													
	Base Load Forecast	2014 IEPR Up	12533	12658	12814	12976	13137	13307	13464	13611	13755	13884	14017
less	Load Forecast Adjustment (positive is a decrease)		0	0	0	0	0	0	0	0	0	0	0
less	AAEE	2014 IEPR Up	93	186	280	344	416	480	543	607	686	766	854
less	Preferred EE	SCE RFO	0	5	24	99	120	128	130	120	109	98	88
less	Preferred BTM Energy Storage	SCE RFO	0	0	25	163	169	172	170	172	172	172	172
less	Preferred BTM DG	SCE RFO	0	0	11	40	40	40	40	40	40	40	40
=	Managed Load Forecast		12440	12467	12475	12331	12392	12487	12580	12672	12748	12809	12862
	Gross Local Capacity Requirements		4916	4898	5122	5316	5279	5473	5960	6124	6302	6480	6668
less	T-system Upgrade Impacts		(240)	(240)	(240)	(240)	0	0	(300)	(300)	(300)	(300)	(300)
less	LCR Change from Demand Adjustments		(93)	(191)	(339)	(645)	(745)	(820)	(884)	(939)	(1007)	(1075)	(1154)
=	Adjusted LCR		4583	4467	4543	4431	4534	4653	4776	4884	4995	5105	5214
	OTC Non Nuclear	ScenTool	4153	3818	3818	3818	3818	2238	0	0	0	0	0
plus	OTC Nuclear	ScenTool	0	0	0	0	0	0	0	0	0	0	0
plus	Hydro	ScenTool	15	15	15	15	15	15	15	15	15	15	15
plus	Solar	ScenTool	0	0	0	0	0	0	0	0	0	0	0
plus	Wind	ScenTool	13	13	13	13	13	13	13	13	13	13	13
plus	Geothermal	ScenTool	0	0	0	0	0	0	0	0	0	0	0
plus	Biomass	ScenTool	91	91	91	91	91	91	91	91	91	91	91
plus	Cogeneration	ScenTool	491	491	491	491	491	491	491	462	462	462	462
plus	Pump	ScenTool	0	0	0	0	0	0	0	0	0	0	0
plus	Non OTC Peaker	ScenTool	733	688	688	688	688	688	688	688	688	688	688
plus	Non OTC Thermal	ScenTool	1277	1277	1277	1277	1277	1277	1277	1277	1277	1277	1277
plus	Various and Unknown	ScenTool	12	12	12	12	12	12	12	12	12	12	12
plus	Incr. Peaker Additions	SCE RFO	0	0	0	0	0	0	98	98	98	98	98
plus	Incr. Thermal Additions	SCE RFO	0	0	0	0	0	1280	1280	1280	1280	1280	1280
plus	Incr. RPS Calc - Renew	14/15 Port	0	0	0	0	0	0	0	0	0	0	0
plus	Incr. RPS Calc - DG	14/15 Port	0	97	97	101	104	107	116	135	160	160	160
plus	Storage Additions	SCE RFO	0	0	0	0	0	0	100	100	100	100	100
plus	DR Program/Preferred DR Capability		164	167	169	177	180	182	185	182	182	182	182
=	Total Resources Base		6948	6668	6671	6683	6688	6395	4365	4353	4378	4378	4378
=	Resource Need (Surplus/Deficit) Base		2365	2201	2128	2252	2154	1742	(411)	(532)	(617)	(727)	(836)

Source: California Energy Commission staff

Table B-4: Baseline Results for San Diego-Imperial Valley Area

	Variables (Summer Peak MW)	Source	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
San Diego/Imperial Valley Area													
	Base Load Forecast	2014 IEPR Up	5324	5372	5453	5529	5602	5654	5698	5742	5778	5814	5850
less	Load Forecast Adjustment (positive is a decrease)		0	0	0	0	0	0	0	0	0	0	0
less	AAEE	2014 IEPR Up	39	78	118	146	181	213	245	280	319	358	401
less	Preferred EE	ISO 14/15 TPP	0	0	0	3	7	10	13	17	20	18	16
less	Preferred BTM Energy Storage	ISO 14/15 TPP	0	0	0	0	26	26	26	26	26	26	26
less	Preferred BTM DG	ISO 14/15 TPP	0	0	0	0	0	0	0	0	0	0	0
=	Managed Load Forecast		5285	5294	5335	5380	5389	5405	5414	5420	5413	5413	5407
	Gross Local Capacity Requirements		4189	3430	4011	4227	3963	3937	5869	5927	5988	6049	6115
less	T-system Upgrade Impacts		(240)	(240)	(840)	(1086)	(846)	(846)	(846)	(846)	(846)	(846)	(846)
less	LCR Change from Demand Adjustments	input value	(39)	(78)	(118)	(149)	(213)	(249)	(284)	(322)	(365)	(401)	(443)
=	Adjusted LCR Base		3910	3112	3054	2992	2904	2842	4739	4758	4777	4802	4826
less	OTC Non Nuclear	ScenTool	965	965	859	0	0	0	0	0	0	0	0
less	OTC Nuclear	ScenTool	0	0	0	0	0	0	0	0	0	0	0
less	Hydro	ScenTool	44	44	44	44	44	44	44	44	44	44	44
less	Solar	ScenTool	483	633	633	633	633	633	633	633	633	633	633
less	Wind	ScenTool	36	56	56	56	56	56	56	56	56	56	56
less	Geothermal	ScenTool	0	0	0	0	0	0	0	0	0	0	0
less	Biomass	ScenTool	21	21	21	21	21	21	21	21	21	21	18
less	Cogeneration	ScenTool	135	135	135	135	135	154	154	154	154	154	154
less	Pump	ScenTool	0	0	0	0	0	0	0	0	0	0	0
less	Non OTC Peaker	ScenTool	513	626	513	513	513	513	513	513	513	513	513
less	Non OTC Thermal	ScenTool	2298	2298	2298	2298	2298	2298	2298	2298	2298	2298	2298
less	Various and Unknown	ScenTool	1	1	1	1	1	1	1	1	1	1	1
less	Incr. Peaker Additions	Picker AD	0	0	308	808	808	808	808	808	808	808	808
less	Incr. Thermal Additions	D14-03-004	0	0	0	0	0	0	0	0	0	0	0
less	Incr. RPS Calc - Renew	14/15 Port	0	65	65	65	65	65	65	65	65	65	65
less	Incr. RPS Calc - DG	14/15 Port	0	25	36	37	41	45	52	53	64	64	64
less	Storage Additions	D14-03-004	0	0	0	0	0	0	0	0	0	0	0
less	DR Program Capability/Preferred DR Capab	multiple	19	19	19	20	20	21	21	21	21	21	21
=	Total Resources Base		4513	4887	4987	4630	4634	4658	4666	4667	4678	4678	4675
=	Resource Need (Surplus/Deficit) Base		603	1775	1933	1638	1730	1816	(73)	(92)	(100)	(124)	(151)

Source: California Energy Commission staff

Table B-5: Baseline Results for San Diego Subarea

	Variables (Summer Peak MW)	Source	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
San Diego Sub-Area													
	Base Load Forecast	2014 IEPR Up	5324	5372	5453	5529	5602	5654	5698	5742	5778	5814	5850
less	Load Forecast Adjustment (positive is a decrease)		0	0	0	0	0	0	0	0	0	0	0
less	AAEE	2014 IEPR Up	39	78	118	146	181	213	245	280	319	358	401
less	Preferred EE	ISO 14/15 TPP	0	0	0	3	7	10	13	17	20	18	16
less	Preferred BTM Energy Storage	ISO 14/15 TPP	0	0	0	0	26	26	26	26	26	26	26
less	Preferred BTM DG	ISO 14/15 TPP	0	0	0	0	0	0	0	0	0	0	0
=	Managed Load Forecast		5285	5294	5335	5380	5389	5405	5414	5420	5413	5413	5407
	Gross Local Capacity Requirements		3382	3430	4011	4227	3963	3937	4129	4187	4248	4309	4375
less	T-system Upgrade Impacts		(240)	(240)	(840)	(1086)	(846)	(846)	(846)	(846)	(846)	(846)	(846)
less	LCR Change from Demand Adjustments	input value	(39)	(78)	(118)	(149)	(213)	(249)	(284)	(322)	(365)	(401)	(443)
=	Adjusted LCR Base		3103	3112	3054	2992	2904	2842	2999	3018	3037	3062	3086
less	OTC Non Nuclear	ScenTool	965	965	859	0	0	0	0	0	0	0	0
less	OTC Nuclear	ScenTool	0	0	0	0	0	0	0	0	0	0	0
less	Hydro	ScenTool	44	44	44	44	44	44	44	44	44	44	44
less	Solar	ScenTool	37	37	37	37	37	37	37	37	37	37	37
less	Wind	ScenTool	5	5	5	5	5	5	5	5	5	5	5
less	Geothermal	ScenTool	0	0	0	0	0	0	0	0	0	0	0
less	Biomass	ScenTool	21	21	21	21	21	21	21	21	21	21	18
less	Cogeneration	ScenTool	135	135	135	135	135	154	154	154	154	154	154
less	Pump	ScenTool	0	0	0	0	0	0	0	0	0	0	0
less	Non OTC Peaker	ScenTool	513	626	513	513	513	513	513	513	513	513	513
less	Non OTC Thermal	ScenTool	1218	1218	1218	1218	1218	1218	1218	1218	1218	1218	1218
less	Various and Unknown	ScenTool	1	1	1	1	1	1	1	1	1	1	1
less	Incr. Peaker Additions	Picker AD	0	0	308	808	808	808	808	808	808	808	808
less	Incr. Thermal Additions	D14-03-004	0	0	0	0	0	0	0	0	0	0	0
less	Incr. RPS Calc - Renew	14/15 Port	0	0	0	0	0	0	0	0	0	0	0
less	Incr. RPS Calc - DG	14/15 Port	0	25	36	37	41	45	52	53	64	64	64
less	Storage Additions	D14-03-004	0	0	0	0	0	0	0	0	0	0	0
less	DR Program Capability/Preferred DR Capab	multiple	19	19	19	20	20	21	21	21	21	21	21
=	Total Resources Base		2956	3094	3195	2838	2842	2866	2874	2875	2886	2886	2883
=	Resource Need (Surplus/Deficit) Base		(147)	(18)	141	(154)	(62)	24	(126)	(144)	(152)	(176)	(203)

Source: California Energy Commission staff

Table B-6: Baseline Results for Eastern L.A. Basin Subarea

	Variables (Summer Peak MW)	Source	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Eastern LA Sub-Area (a subarea within LA Basin)													
	Base Load Forecast	2014 IEPR Up	8673	8760	8868	8980	9092	9209	9317	9420	9519	9609	9700
less	Load Forecast Adjustment (positive is a decrease)		0	0	0	0	0	0	0	0	0	0	0
less	AAEE	2014 IEPR Up	30	61	93	117	143	169	195	221	250	278	310
less	Preferred EE	SCE RFO	0	0	0	0	0	0	0	0	0	0	0
less	Preferred BTM Energy Storage	SCE RFO	0	0	0	0	0	0	0	0	0	0	0
less	Preferred BTM DG	SCE RFO	0	0	0	0	0	0	0	0	0	0	0
=	Managed Load Forecast		8643	8699	8775	8863	8948	9040	9123	9199	9269	9330	9390
	Gross Local Capacity Requirements		2230	2271	2187	2096	2007	1917	2603	2728	2856	2984	3115
less	T-system Upgrade Impacts		0	0	0	0	0	0	0	0	0	0	0
less	LCR Change from Demand Adjustments	input value	(30)	(61)	(93)	(117)	(143)	(169)	(195)	(221)	(250)	(278)	(310)
=	Adjusted LCR Base		2200	2210	2095	1979	1864	1748	2408	2507	2607	2706	2805
less	OTC Non Nuclear	ScenTool	0	0	0	0	0	0	0	0	0	0	0
less	OTC Nuclear	ScenTool	0	0	0	0	0	0	0	0	0	0	0
less	Hydro	ScenTool	292	292	293	293	293	293	293	293	293	293	293
less	Solar	ScenTool	22	22	22	22	22	22	22	22	22	22	22
less	Wind	ScenTool	46	46	46	46	46	46	46	46	44	44	43
less	Geothermal	ScenTool	0	0	0	0	0	0	0	0	0	0	0
less	Biomass	ScenTool	6	6	6	6	6	6	6	6	6	6	6
less	Cogeneration	ScenTool	220	220	220	220	220	220	220	220	220	220	190
less	Pump	ScenTool	0	0	0	0	0	0	0	0	0	0	0
less	Non OTC Peaker	ScenTool	466	466	466	466	466	466	466	466	466	466	466
less	Non OTC Thermal	ScenTool	3035	2715	2395	2395	2395	2395	2395	2395	2395	2395	2395
less	Various and Unknown	ScenTool	21	21	21	21	21	21	21	21	21	21	21
less	Incr. Peaker Additions	SCE RFO	0	0	0	0	0	0	0	0	0	0	0
less	Incr. Thermal Additions	SCE RFO	0	0	0	0	0	0	0	0	0	0	0
less	Incr. RPS Calc - Renew	na	0	0	0	0	0	0	0	0	0	0	0
less	Incr. RPS Calc - DG	na	0	6	6	6	7	7	7	9	10	10	10
less	Storage Additions	SCE RFO	0	0	0	0	0	0	0	0	0	0	0
less	DR Program Capability	multiple	0	0	0	0	0	0	0	0	0	0	0
=	Total Resources Base		4108	3794	3474	3475	3475	3475	3476	3477	3477	3477	3444
=	Resource Need (Surplus/Deficit) Base		1908	1584	1380	1496	1611	1727	1068	970	870	771	639

Source: California Energy Commission staff

APPENDIX C:
Numeric Results of Alternative Scenarios

Table C-1: LCAAT Results for Baseline and Alternative Scenarios—Area-Specific Surpluses or Deficits (MW)

Case	Area	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
2016 Baseline S/D	LA Basin/San Diego Subarea	1813	1563	1373	1247	1286	1005	531	294	102	(132)	(400)
	LA Basin	1959	1580	1232	1401	1349	981	656	438	253	44	(197)
	West LA Basin Only (subset of LA Basin)	2365	2201	2128	2252	2154	1742	(411)	(532)	(617)	(727)	(836)
	San Diego/Imperial Valley Area	603	1775	1933	1638	1730	1816	(73)	(92)	(100)	(124)	(151)
	San Diego Sub-Area	(147)	(18)	141	(154)	(62)	24	(126)	(144)	(152)	(176)	(203)
	Eastern LA Sub-Area (a subarea within LA Basin)	1908	1584	1380	1496	1611	1727	1068	970	870	771	639
2016HighSurplus S/D	LA Basin/San Diego Subarea	3509	3428	3396	3572	3982	4024	3795	3399	3094	2758	2379
	LA Basin	3200	2947	2729	3132	3378	3281	3184	2875	2626	2361	2053
	West LA Basin Only (subset of LA Basin)	3099	3010	3014	3277	3358	3106	1087	913	790	647	498
	San Diego/Imperial Valley Area	1059	2230	2373	2103	2224	2320	402	267	164	45	(72)
	San Diego Sub-Area	309	481	667	440	604	743	612	525	468	397	326
	Eastern LA Sub-Area (a subarea within LA Basin)	2416	2142	1990	2201	2438	2663	2097	1962	1836	1714	1555
2016Pessimistic S/D	LA Basin/San Diego Subarea	1748	1299	877	563	405	(104)	(776)	(1508)	(1944)	(2538)	(3000)
	LA Basin	1910	1374	837	859	651	99	(382)	(1052)	(1434)	(1861)	(2247)
	West LA Basin Only (subset of LA Basin)	2328	2063	1859	1891	1696	1188	(1061)	(1547)	(1737)	(2002)	(2222)
	San Diego/Imperial Valley Area	588	1717	1832	1497	1546	1589	(343)	(405)	(458)	(625)	(700)
	San Diego Sub-Area	(162)	(75)	40	(295)	(246)	(203)	(395)	(457)	(511)	(677)	(752)
	Eastern LA Sub-Area (a subarea within LA Basin)	1896	1516	1254	1314	1372	1399	680	495	303	141	(25)

Source: California Energy Commission staff