BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

OPENING BRIEF OF THE DIVISION OF RATEPAYER ADVOCATES ON LOCAL RELIABILITY ISSUES

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INTRODUCTION

Pursuant to Rule 13.11 of the California Public Utilities Commission's (Commission's) Rules of Practice and Procedure and consistent with Administrative Law Judge Gamson's direction at the close of hearings,[1] the Division of Ratepayer Advocates (DRA) submits its opening brief on Local Reliability issues in Track 1 of this rulemaking.

The May 17, 2012 "Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge" (Scoping Memo) explained the relationship between this long-term procurement planning (LTPP) proceeding and the Commission's Resource Adequacy (RA) proceeding, currently rulemaking (R.) 11-10-023. The Scoping Memo noted that the California Independent System Operator (CAISO or ISO) in recent years has completed annual Local Capacity Requirements (LCR) studies, which are filed in the Commission's RA proceedings. Each LCR study forms the basis for the Commission's adoption of local RA procurement requirements for the next year.[2] The Scoping Memo also described the interplay between the RA proceeding and the Local Reliability phase (Track 1) of this proceeding:

> "In past RA decisions, the Commission has focused on LCR for local reliability for one forward year…. ..In the Local Reliability track of this proceeding, we will consider authorizing procurement of new infrastructure for local reliability purposes"[3]

A number of once-through cooling (OTC) power plants are expected to retire in the local transmission-constrained areas of the Los Angeles (LA) Basin, and Big Creek/Ventura because of State Water Resources Control Board (SWRCB) regulations designed to implement requirements of the federal Clean Water Act. The CAISO completed a study of potential local capacity needs through 2021 arising from the potential retirements of OTC plants. The Scoping Memo emphasizes that:

> "parties will have the opportunity to present evidence that the ISO's studies should be modified, or that the Commission should

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[1] Reporter's Transcript (RT) 1384:18-21, 26-28.

[2] Scoping Memo at 3.

[3] Scoping Memo at 3.

consider additional factors beyond the ISO's studies, for the purposes of determining local reliability needs."[4]

DRA's recommendation on LCR needs and other issues in the Local Reliability phase of this proceeding as listed in the Scoping Memo and set forth in the common briefing outline are summarized and explained below.

I. EXECUTIVE SUMMARY

DRA makes the following recommendations on local reliability issues in Track 1 of this proceeding:

- The Commission should authorize Southern California Edison Company (SCE) to procure up to 169 megawatts (MW) for 2021, and up to 278 MW for 2022 for residual LCR need in the LA Basin, and should reevaluate LCR need for the LA Basin in the 2014 LTPP proceeding.

- The Commission should determine that there is no LCR need for the Big Creek/Ventura area in this LTPP, and evaluate the need for SCE to procure new LCR resources in the Big Creek/Ventura area in the 2014 LTPP proceeding.

- If the Commission authorizes SCE to procure up to 169 MW for 2021 and up to 278 MW for 2022 for the LA Basin, then the Commission should grant SCE the flexibility to demonstrate at the time it submits its application for approval of LCR procurement that the LCR resources for which SCE seeks approval are cost-effective and consistent with the loading order.

- If the Commission authorizes SCE to procure more than 169 MW for 2021 and more than 278 MW for 2022, then it should require SCE to include stakeholder participation in the process for determining whether preferred[5] resources can cost-effectively reduce LCR need <u>prior</u> to submission of its application. The Commission has requested comments related to the development of such a process following the September 7, 2012 workshop held jointly in this proceeding and the energy storage proceeding, R.10-12-007. That process for evaluating preferred resources should be used to evaluate acquisition of preferred resources to meet LCR need by Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E) as well as SCE.[6]

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[4] Scoping Memo at 5.

[5] "Preferred" resources are energy resources consistent with California's Loading Order, which requires the procurement of energy efficiency and other demand-side resources first, then renewable resources, and finally, conventional generation. D.07-12-052, Finding of Fact 8 at 271.

[6] DRA's Opening Brief on Local Reliability Issues refers collectively to PG&E, SCE, and SDG&E as Utilities.

- The Commission should allow, but not require SCE to procure "flexible"[7] capacity to meet LCR needs. The Commission should not direct the procurement of flexible capacity until the definition of flexible capacity is determined in the RA rulemaking, R.11-10-023.

- The Commission should direct SCE to work with the CAISO, with all due speed, to identify, analyze and ultimately implement additional cost-effective transmission solutions[8] that will reduce LCR need. The Commission should direct SCE to identify and complete a comprehensive analysis of all reasonable alternatives and present such analysis to the Commission no later than the time of the commencement of the 2014 LTPP proceeding.[9]

- The Commission should direct SCE to work with the Los Angeles Department of Water and Power to identify and implement any coordinated dispatch solutions that will reduce LCR need.

- The Commission should direct SCE to work with the CAISO to determine a priority-ordered listing of the most electrically beneficial locations for preferred resource deployment (supply or demand side) to maximize such resources' ability to reduce LCR need.

- The Commission should deny SCE's request for authority to adjust its capital structure outside its cost of capital proceeding.

- The Commission should allocate the net capacity costs of authorized LCR procurement to all benefiting customers, consistent with Public Utilities Code Section 365.1 (c) (2) (B).

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[7] The attributes of flexible capacity have not yet been completely defined, but flexible capacity generally means capacity that can be dispatched and controlled quickly in response to changing system need. Exhibit (Ex.) ISO 4 (Testimony of Mark Rothleder on behalf of the CAISO) at 8:15-30.

[8] For example, such transmission solutions could include reconductoring existing lines. When transmission conductor is replaced with a conductor rated to carry a higher voltage, the line is said to be reconductored.

[9] However, if the Commission authorizes additional LCR beyond the amounts recommended by DRA, such analysis should be considered by the Commission prior to the 2014 LTPP.

- The Commission should count uncommitted[10] preferred resources as reducing LCR need in this proceeding, as well as in Application (A).11-05-023 (Application of San Diego Gas & Electric Company for Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center and Quail Brush Power).

II. DETERMINATION OF LOCAL CAPACITY REQUIREMENTS (LCR) NEED IN CALIFORNIA INDEPENDENT SYSTEM OPERATOR (CAISO) STUDIES

The Commission will determine in Track 1 of this proceeding the amount of new resources needed to meet LCR following the anticipated retirement of generating resources located in the LA Basin and the Big Creek/Ventura areas, two local capacity areas in SCE's service territory:[11] The generating resources will retire to comply with California's policy governing OTC plants as implemented by the SWRCB.

A local capacity area is a geographic area without sufficient transmission import capability to serve the electrical demand in the area that therefore requires the operation of generation located within that area to meet customer demand.[12] The minimum amount of resources needed within a local capacity area to address reliability concerns following the occurrence of contingencies[13] on the electric system is known as the local capacity requirement or LCR.[14] The need for new resources or residual LCR need is computed by subtracting available resources from the total LCR need.

A. CAISO's LCR and Once-Through Cooling (OTC) Generation Studies

The CAISO made LCR recommendations in this proceeding based on the OTC study developed as part of its 2011/2012 Transmission Planning process.[15] The CAISO is responsible

[10] Uncommitted" resources generally refers to energy resources for which the funding has not yet been authorized. RT 903:15-27, DRA/Fagan.

[11] The Commission will determine the LCR for SDG&E in Application (A.) 11-05-023. The CAISO concluded that the potential retirement of OTC plants in PG&E's service territory is not expected to produce local capacity deficiencies and is therefore not an issue in this proceeding. Ex. ISO 1 (Testimony of Robert Sparks on behalf of the CAISO) at 3:4-5.

[12] Ex. ISO 1/ Sparks at 3:28-30.

[13] A contingency is the outage of one or more transmission or generation elements on the electric system.

[14] Ex. ISO 1/ Sparks at 3:16-19.

[15] Ex. ISO 7 (Chapter 3 of 2011/2012 ISO Transmission Plan).

for operating the transmission grid used by SCE, PG&E, and SDG&E "consistent with achievement of planning and reserve criteria no less stringent than those established by the Western Electricity Coordinating Council [WECC] and the North American Reliability [Corporation] [NERC]."[16] Robert Sparks, the CAISO witness who oversees engineers responsible for planning the CAISO controlled transmission system in southern California, explained that the purpose of his testimony is:

> "to describe the local capacity needs for the Los Angeles Basin and Big Creek/Ventura areas that the ISO has identified through its once through cooling (OTC) study conducted as part of the ISO's 2011-2012 transmission planning process. This assessment identifies the minimum amount of resources within transmission constrained areas that must be available to support the reliable operation of the transmission system assuming that the generating resources subject to California's OTC policies retire or otherwise become unavailable."[17]

The CAISO's OTC study assesses the need for generation capacity or load-reducing demand-side resources in the CAISO-controlled portion of the LA Basin and the Big Creek/Ventura local capacity areas for the 2021 timeframe,[18] including the impact of anticipated generation plant closures on forecasted power system supply/demand balances for 2021.[19] The OTC study examines whether the output of soon to-be-retired OTC plants, or equivalent new resources, will be required to meet the minimum LCR need in any given area.[20]

The CAISO's OTC study conducted in the 2011-12 Transmission plan represents the first time the CAISO has conducted an LCR study for a 10-year planning horizon. Unlike CAISO's typical LCR or Local Capacity Technical (LCT) studies filed in the Commission's RA proceedings, which examine the need for resource adequacy one year ahead, this OTC study evaluates potential need for new resources over a much longer time frame.[21] How to utilize LCR

[16] Public Utilities Code 345.

[17] Ex. ISO 1/Sparks at 2:3-9.

[18] Ex. DRA 1 (Testimony of Robert M. Fagan on behalf of DRA) at 5:15-18.

[19] Ex. DRA 1/Fagan at 6:4-8.

[20] Ex. DRA 1/Fagan at 6:8-13.

[21] RT 79:7-15, ISO/Sparks.

studies for long-term planning is a novel question for the Commission, and the longer planning horizon greatly increases the uncertainty of the evaluation.[22]

1. CAISO's Primary Recommendation

The CAISO summarized its OTC study results as presented in Table 1 below:

Table 1: CAISO Summary of OTC (2021) study results[23]

Local Area	Local Area Requirements (MW)				Replacement OTC Generation Need (MW)			
	Trajectory	Environmentally Constrained	ISO Base Case	Time Constrained	Trajectory	Environmentally Constrained	ISO Base Case	Time Constrained
LA Basin (this area includes sub-area below)	10,743	11,246	11,010	12,165	2,370 – 3,741	1,870 – 2,884	2,424 – 3,834	2,460 – 3,896
Western LA Basin (sub-Area of the larger LA Basin)	7,797	7,564	7,517	7,397				
Big Creek/Ventura (BC/V) Area	2,371	2,604	2,438	2,653	(Need is for Moorpark only, a sub-area of the Big Creek/Ventura Local area)			
					430	430	430	430

The CAISO recommends use of the results of its "Trajectory Scenario," which produces a range of residual LCR need from 2,370 MW to 3,741 MW in the LA Basin as shown above.[24]

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[22] The Commission faces the same issue--how to use the OTC study for long-term planning--in A.11-05-023, SDG&E's application for the approval of three new purchase power tolling agreements.

[23] Ex. ISO 1/Sparks at 6.

[24] Ex. ISO 1/Sparks at 17:4-8.

The variability of the CAISO's claimed need depends on the electrical location of the resources, with the lower end of the range representing sites that are most effective (at resolving modeled transmission constraints) and the higher end of the range representing locations that are least effective in resolving transmission constraints.[25] All four CAISO scenarios produce 430 MW of residual LCR need for the Big Creek/Ventura area.

As explained below, CAISO's OTC summary results greatly overestimate the residual LCR needed by excluding a number of resources that, pursuant to Commission policies and decisions, should be available to meet LCR need in 2021 and 2022. DRA performed its own analysis of the OTC study results, and included reasonably forecasted levels of energy efficiency, demand response, distributed generation, and combined heat and power. Based on that analysis, DRA recommends that the Commission authorize SCE to procure up to169 MW for 2021 and up to 278 MW for 2022 to meet residual LCR need in the LA basin,[26] and that the Commission find that there is no residual LCR need for the Big Creek/Ventura area,[27] but reevaluate the need for the Big Creek/Ventura area in the 2014 LTPP proceeding.

2. CAISO's Sensitivity Analysis

In addition to the results presented in Mr. Sparks' Opening Testimony, Mr. Sparks' supplemental testimony presented the results of CAISO's Sensitivity Analysis, which reflected the mid-net load scenario using the 2021 environmentally constrained portfolio, including incremental uncommitted energy efficiency (EE) and additional combined heat and power (CHP), as well as the modeling of the Del Amo – Ellis 230kV loop-in project.[28] The Sensitivity Analysis included 1,121 MW of incremental uncommitted EE[29] and 180 MW of CHP,[30] but included no demand response (DR).[31] The CAISO's Sensitivity Analysis showed a range of residual LCR need for the Western LA Basin of between 1042 and 1667 MW.[32]

[25] Ex. ISO 1/Sparks at 6:17-22.

[26] Ex. DRA 6 (Reply Testimony of Robert M. Fagan) at 4:4-7.

[27] Ex. DRA 1/Fagan at 3:17-18.

[28] Ex.IS0 2 (Supplemental Testimony of Robert Sparks) at 2:14-22.

[29] RT 137:19-22, ISO/Sparks; CEJA x ISO 1 at 2.

[30] RT 158:26-159:2, ISO/Sparks; CEJA x ISO 1 at 2.

[31] RT 159:7-17; CEJA x SCE 1 at 3.

[32] Ex.IS0 2/Sparks, Table 2 at 3.

The CAISO explained that in preparing the OTC study summarized in Exhibit ISO 1, it relied on the California Energy Commission's (CEC) 2009 Integrated Energy Policy Report (IEPR), which did not include uncommitted EE or CHP.[33] While including incremental EE and CHP in its Sensitivity Analysis, CAISO cautioned against using that Sensitivity Analysis to determine LCR need:

> "To the extent that such uncommitted resources ultimately develop, they can be helpful in reducing overall net demand, but the ISO does not believe it is prudent to rely on uncommitted resources for assessing future local system needs and ensuring the reliability of the bulk power system."[34]

3. SCE did not perform its own analysis of LCR need.

SCE has significant expertise in transmission planning, but did not independently examine LCR need.[35] SCE reviewed the CAISO LCR studies and generally found the results reasonable.[36] Despite its stated belief that the CAISO's LCR recommendations were reasonable,[37] SCE acknowledges the uncertainty in results that are nine to ten years in the future, and disagrees with some aspects of the CAISO's studies.[38] SCE points out that "the nature and effect of the additional CAISO planning standards included in the CAISO's analysis are unclear"[39]

Notwithstanding uncertainties related to the CAISO OTC study, SCE found the CAISO's analysis of LCR need for the LA Basin reasonable.[40] SCE disagrees with the CAISO's recommendation to authorize 430 MW of LCR need for the Big Creek/Ventura area in this proceeding, and instead recommends that the Commission reevaluate LCR for that area in the 2014 LTPP proceeding.[41]

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[33] RT 394:1-27, CAISO/Millar.

[34] Ex. ISO 2/Sparks at 4:16-19.

[35] RT 936:18--937:20, SCE/Minick.

[36] Ex. SCE 1/Minick at 4:22-5:5, 5:17-18.

[37] Ex. SCE 1/Minick at 5:4-5.

[38] Ex. SCE 1/Minick at 5:11-12; RT 939:27--940:9, SCE/Minick.

[39] Ex. SCE 1/Minick at 6:10-11; *see also* Ex. SCE 1/Silsbee at 4:4-6; Ex. SCE 1/Minick at 5:9-21.

[40] Ex. SCE 1/Minick at 4:22.

[41] Ex. SCE 1/Cushnie at 3:1-3; Ex. SCE/1 Minick at 10:12-22.

4. Notwithstanding the use of different modeling tools, DRA's inclusion of incremental preferred resources in the 2021 supply/demand balance for local areas, in contrast to the CAISO's exclusion of such resources, is the primary reason for the difference in the amount of new resources recommended by DRA and by the CAISO.

The CAISO completed technical evaluations using power flow and transient stability programs for four renewable portfolio standard (RPS) scenarios.[42] A power flow modeling tool is:

> "a complex piece of software that mathematically simulates the core electrical attributes of the power system. Transmission planners rely heavily on power flow simulation tools to assess transmission needs. Use of these tools can also help to determine the minimum level of resource needed for a given area, such as the LA Basin, to ensure that supply and demand will be in balance even under low likelihood events, and that the state of the power system will be reliable."[43]

In evaluating potential new-resource need resulting from OTC retirement, DRA used a different approach. Rather than power flow modeling, DRA used a load and resource balance approach to estimate new resource need in the LA Basin and Big Creek/Ventura in each of the years 2012 through 2022, after accounting for OTC resource retirement and the amount of existing resources. DRA witness Robert Fagan explained that:

> "A load and resources balance approach is a simplified accounting of supply, demand, and import capacity for the LA Basin and Big Creek/Ventura local capacity areas. It uses two key simplifications compared to the power flow model method. First, it uses a single value to represent the level of transmission imports that can be counted on when considering capacity needs for each of the local areas. Second, it aggregates all supply and demand into a single zone, for the purpose of balancing local supply, imports, and demand."[44]

[42] Ex. ISO 1/Sparks at 4:20-24.

[43] Ex. DRA 1/Fagan at 7:5-11.

[44] Ex.DRA 1/Fagan at 8:4-10.

Mr. Fagan explained that power flow modeling is useful in assessing the state of the power system under "contingency" conditions, including the unavailability of generation resources and transmission equipment, but that using power flow modeling for a "time period 10 years in the future can lead to exaggerated precision in its outputs – i.e., transmission configuration, and especially supply and demand inputs are likely to be different, perhaps significantly so, in 10 years."[45] Nonetheless, Mr. Fagan directly used the information from CAISO's analysis to inform his estimate of transmission imports into the local regions. These estimates account for the reduced capacity of the transmission system under contingency conditions.

Mr. Sparks acknowledged that the precision of power flow simulations are subject to the accuracy of input assumptions:

> "Any sort of computer simulation program that is entirely – the accuracy is completely dependent on how accurate the input assumptions are whether it is the load assumptions, generation assumptions, transmission system network modeling assumptions."[46]

Mr. Sparks also agreed that looking so far into the future makes forecasting more complicated, noting that with "the ten year time frame there's more uncertainty on many factors."[47]

Notwithstanding DRA's use of a load and resource table rather than power flow modeling to estimate new resources needed in the LA Basin and Big Creek/Venture in 2021, the main driver in the different residual LCR need resulting from the CAISO's methodology and DRA's methodology was not the analytical tool. Instead, the primary driver was DRA's use of different the input assumptions: DRA included reasonable amounts of uncommitted preferred resources in analyzing future LCR needs. The CAISO, however, excluded uncommitted preferred resources from its OTC study, except in its Sensitivity Analysis, where the CAISO included uncommitted EE and CHP, but not uncommitted DR.

Mr. Sparks acknowledged that after including DR that DRA forecasted for 2021, the estimated new resource need for the LA Basin resulting from DRA's load and resource analysis[48]

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[45] Ex.DRA 1/Fagan at 9:3-7.

[46] RT 167:2-11, ISO/Sparks.

[47] RT 79:16:22, ISO/Sparks.

was in the same range as CAISO's Sensitivity Analysis using power flow modeling.[49] Thus, even though DRA calculated the new resource need using a load and resource tabulation rather than a power flow analysis, that is not the source of the primary difference between DRA's and CAISO's recommendations for required new resources in SCE's LCR areas.[50]

B. Consideration of Preferred Resources, Including Uncommitted Energy Efficiency, Demand Response, Combined Heat and Power, and Distributed Generation, in Determining Future LCR Needs

1. DRA included reasonable amounts of preferred resources in calculating future resource need.

The Energy Action Plan guides California's energy policies, and sets forth a loading order of preferred resources to meet energy needs, which places energy savings from or reduction in need due to EE, DR, and distributed generation such as CHP at the top of the loading order.[51] In evaluating future LCR needs, and new resource needs (which are computed by subtracting existing resources from the total LCR need) the CAISO did not include any EE, DR, or CHP in its OTC study, other than some uncommitted EE and CHP in the Sensitivity Analysis that CAISO recommends against.

Including preferred resources in the forecast of new resource need in 2021 and 2022 produced significantly lower new resource need as summarized below in DRA Tables 2, 3, and 4 and complies with loading order in the Energy Action Plan.

Starting with the 1-in-10 gross peak demand from the CEC,[52] Tables 2, 3, and 4 calculate net peak demand by including:

- Uncommitted EE estimates from CEC's Demand Analysis Working Group;[53]

(continued from previous page)

[48] DRA's load and resource tables are discussed in greater detail in below and reproduced at pages 13-15 of this brief.

[49] RT 1342:12-18, CAISO/Sparks (Q: [S]o the difference between what you calculated using the sensitivity analysis and the power flow tool and what Mr. Fagan calculated using the load and resources table but including demand response is basically within the same range; is that correct? A:Yes.

[50] Ex.DRA 1/Fagan at 4:3-6.

[51] *See* http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF .

[52] Ex.DRA 4, (Prepared Testimony of Yakov Lasko) at 1-2.

[53] Ex. DRA 1/Fagan at 20:5-9; Ex. DRA 4/Lasko at 4:13-15 and Attachment C.

- DR resources, as evaluated in SCE's 2011 *Demand Response Load Impact Evaluation;*[54] and
- CHP, as evaluated in *Combined Heat and Power: Policy analysis and 2011-2013 Market Assessment.*[55]

DRA allocated the forecasted amounts of uncommitted EE, DR resources, and CHP to the LA Basin and Big Creek/Ventura areas in proportion to each area's demand as a percentage of SCE's total service area demand.[56]

DRA calculated that the new resource need for the LA Basin was reduced dramatically from the CAISO's recommended range of 2,370 to 3,741 MW to a surplus of 845 MW in 2020, declining to a surplus of 489 MW in 2022 as shown below in Table 2, line O.[57]

[54] Ex. DRA 4/Lasko at 6:2-3; *Demand Response Load Impact Evaluation*, prepared by Freeman, Sullivan and Company on May 30, 2012, excerpts appended to Ex. DRA 4/Lasko as Attachment D.

[55] Ex. DRA 4/Lasko at 7:5-6; *Combined Heat and Power: Policy analysis and 2011-2013 Market Assessment,* prepared by the CEC by ICF International, excerpts appended to Ex. DRA 4/Lasko as Attachment E.

[56] Ex DRA 4/Lasko at 4:4-8.

[57] Ex. DRA 1 A 2 (Amendment to Testimony of Robert M Fagan, served August 8, 2012) at 3:15-17.

Table2: DRA's Analysis of the Rangeof Resource "Deficiency" or "Surplus", LA BasinLocalArea,2012-2022

LA Basin Overall LCR Scenario based on May 31 2012 CEC Load Forecast, SCE DAWG EE and DR, CAISO Transmission Imports to LA Basin															
Row	**Item**		**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**		
A	Gross peak load LA Basin LCR Area 1 in 10 (CEC Revised Feb. 2012 Form 1.5d), MW			19,974	20,452	20,806	21,080	21,382	21,644	21,913	22,202	22,492	22,778	23,060	
B	Uncommitted EE (6/18/2012 DAWG Mid-case SCE / 81.2% LA Basin share), MW			5	68	158	294	414	518	593	708	814	906	995	
C	Uncommitted EE rest of CAISO LA Basin utilities (est. at 50% of SCE's effort, proportionate to peak load)			0	4	9	17	24	30	34	40	46	51	56	
D	Net peak load (gross peak minus uncommitted EE), MW (A - B - C)			19,969	20,380	20,639	20,769	20,944	21,096	21,287	21,454	21,632	21,821	22,009	
E	Transmission import, MW (CAISO OTC analysis, Env. Case, Tehachapi addition in 2015)			10,592	10,592	10,592	11,592	11,592	11,592	11,592	11,592	11,592	11,592	11,592	
F	Gross LA Basin need before demand response, MW (D - E)			9,377	9,788	10,047	9,177	9,352	9,504	9,695	9,862	10,040	10,229	10,417	
G	Demand response reduction (SCE Load Impact Final Report, LA Basin %			1,260	1,435	1,547	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	
H	Net LA Basin area supply need after DR resources (F - G)			8,117	8,353	8,500	7,627	7,802	7,954	8,144	8,311	8,490	8,678	8,867	
I	Existing supply (CAISO LA Basin, 2012 NQC, p 228) inc. supply side CH			12,083	12,083	12,083	12,083	12,083	12,083	12,083	12,083	12,083	12,083	12,083	
	Retirement path: Alamitos	2,010	MW									(2,010)	(2,010)	(2,010)	
	Retirement path: Huntington Beach	904	MW		(452)	(452)	(452)	(452)	(452)	(452)	(452)	(904)	(904)	(904)	
	Retirement path : El Segundo	670	MW		(335)	(335)	(670)	(670)	(670)	(670)	(670)	(670)	(670)	(670)	
	Retirement path: Redondo Beach	1,356	MW									(1,356)	(1,356)	(1,356)	
J	OTC Total Retirements (Siao, implemention plans, SCE	4,940	MW	-	(787)	(787)	(1,122)	(1,122)	(1,122)	(1,122)	(1,122)	(4,940)	(4,940)	(4,940)	
	El Segundo repower (unit 3 credits 2013, unit 4 credits 2017)				280	280	280	280	560	560	560	560	560	560	
	WalnutCreek(Huntin gton Beach credits)				500	500	500	500	500	500	500	500	500	500	
	Sentinel CPV				850	850	850	850	850	850	850	850	850	850	
K	Total estimated Fossil Resources (El Segundo, Walnut Creek, Sentinel), Known Hi-Probability Additions				1,630	1,630	1,630	1,630	1,910	1,910	1,910	1,910	1,910	1,910	
L	New RPS in LA Basin														
M	New CHP in LA Basin (SCE Base, Yakov testimony from ICF report)			45	68	90	113	147	180	214	248	282	292	303	
N	Totalnet supply(I + J + K + L + M)			12,128	12,994	13,016	12,704	12,738	13,051	13,085	13,119	9,335	9,345	9,356	
O	**Balance: Base Need (+ is surplus, - is deficiency) (N - H)**				**4,641**	**4,517**	**5,077**	**4,936**	**5,097**	**4,941**	**4,808**	**845**	**667**	**489**	

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DRA calculated that LCR need for the Big Creek/Ventura area was reduced from the 430 MW recommended by the CAISO to a surplus of 1,820 MW in 2020 declining to a surplus of 1,757 MW in 2022 as shown below in Table 3, line O.

Table 3: DRA's Analysis of the Range of Resource "Deficiency" or "Surplus", Big Creek/Ventura Local Area, 2012-2022

Scenario BC/Ventura LCR Area based on May 31 2012 CEC Load Forecast, SCE DAWG EE and DR, CAISO Transmission Imports to BC/V													
Row	**Item**		**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
A	Gross peak load BC/Ventura LCR Area 1 in 10 (CEC Revised Feb. 2012 Form 1.5d), MW		3,879	3,962	4,024	4,072	4,125	4,171	4,218	4,268	4,319	4,371	4,421
B	Uncommitted EE (6/18/2012 DAWG Mid SCE / BC/Venturashare), MW		1	13	31	57	80	100	114	137	157	175	192
D	Net peak load (gross peak minus uncommitted EE), MW (A - B)		3,878	3,949	3,993	4,015	4,045	4,071	4,104	4,131	4,162	4,196	4,229
E	Transmissionimport, MW (CAISO, Env. Case for 2021, and 578 MW increase in 2014 from L&R tool)		1,764	1,764	2,342	2,342	2,342	2,342	2,342	2,342	2,342	2,342	2,342
F	Gross LCR need before demand response, MW (D - E)		2,114	2,185	1,651	1,673	1,703	1,729	1,762	1,789	1,820	1,854	1,887
G	Demand response reduction (SCE Load Impact Final Report, BC/Ven		243	277	299	299	299	299	299	299	299	299	299
H	Net LCR supply need after DR resources (F - G)		1,871	1,908	1,353	1,374	1,404	1,430	1,463	1,490	1,521	1,555	1,588
I	Existing supply (CAISO BC/Vent, 2012 NQC, p 240) inc supply side C		5,232	5,232	5,232	5,232	5,232	5,232	5,232	5,232	5,232	5,232	5,232
		MW											
	Retirement path: Ormond Beach	1,516									(1,516)	(1,516)	(1,516)
	Retirement path: Mandalay	430									(430)	(430)	(430)
J	OTC Total Retirements (Siao, implemention plans, SCE	1,946	-	-	-	-	-	-	-	-	(1,946)	(1,946)	(1,946)
K	Total estimated Approved / Under Construction Fossil Resources			-	-	-	-	-	-	-	-	-	-
L	New RPS in BC/Ventura												
M	NewCHP in BC/Ventura(SCE Base, Yakov testimony from ICF repor		9	13	17	22	28	35	41	48	54	56	58
N	Total net supply (I + J + K + L + M)		5,241	5,245	5,249	5,254	5,260	5,267	5,273	5,280	3,340	3,342	3,344
O	**Balance: Base Need (+ is surplus, - is deficiency) (N - H)**		**3,370**	**3,337**	**3,897**	**3,880**	**3,856**	**3,837**	**3,810**	**3,790**	**1,820**	**1,788**	**1,757**

Subsequent to its analysis of new resource need for the entire LA Basin, DRA reviewed the resource needs for the Western LA Basin and determined a potential need for the Western LA Basin. DRA concluded that the need for the Western LA Basin was at most 169 MW for 2021 and 278 MW for 2022 as shown below in Table 4 at Line O.[58]

[58] Ex.DRA 6/Fagan at 8.

Table 4: DRA's Analysis of the Load and Resource Balance for the West LA Basin Sub-Area, 2012-2022

Scenario: W LA Basin LCR Sub-Area based on CAISO 2021 peak load, May 30 2012 CEC Load Forecast, SCE DAWG EE and DR, CAISO Transmission Imports to W LA Basin, 2013 LCT supply resources, ICF CHP														
Row	**Item**	**2012**		**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	
A	Gross peak load West LA Basin LCR sub-area, 1 in 10, CAISO 2021 value, and CEC trend for other years, MW			12,113	12,410	12,595	12,769	12,961	13,129	13,301	13,482	13,664	13,842	14,014
B	Uncommitted EE (West LA Basin proportionate share of total LA Basin), MW			3	44	102	189	266	332	380	454	522	582	638
D	Net peak load (gross peak minus uncommitted EE), MW (A - B)			12,109	12,366	12,493	12,580	12,695	12,797	12,921	13,028	13,142	13,260	13,376
E	Transmission import, MW (CAISO , W. LA Basin, Env. Case for 2021, and 1000 MW increase in 2015 from L&R			5,278	5,278	5,278	6,278	6,278	6,278	6,278	6,278	6,278	6,278	6,278
F	Gross LCR need before demand response, MW (D - E)			6,831	7,088	7,215	6,302	6,417	6,519	6,643	6,750	6,864	6,982	7,098
G	Demand response reduction (SCE Load Impact Final Report, W LA %)			764	871	937	939	940	940	941	941	942	942	942
H	Net LCR supply need after DR resources (F - G)			6,068	6,217	6,279	5,363	5,477	5,579	5,702	5,808	5,922	6,040	6,156
I	Projected 2013 NQC supply (CAISO 2013 LCT study, CAISO 2011-12 Tx plan load flow data)			9,574	9,574	9,574	9,574	9,574	9,574	9,574	9,574	9,574	9,574	9,574
	Retirement path: Alamitos	2,010	MW									(2,010)	(2,010)	(2,010)
	Retirement path: Huntington Beach	904	MW		(452)	(452)	(452)	(452)	(452)	(452)	(452)	(904)	(904)	(904)
	Retirement path: El Segundo	670	MW		(335)		(670)	(670)	(670)	(670)	(670)	(670)	(670)	(670)
	Retirement path: Redondo Beach	1,356	MW									(1,356)	(1,356)	(1,356)
J	OTC Total Retirements (Siao, implemention plans)	4,940	MW	-	(787)	(452)	(1,122)	(1,122)	(1,122)	(1,122)	(1,122)	(4,940)	(4,940)	(4,940)
	El Segundo repower (unit 3 credits 2013, unit 4 credits 2017)				280	280	280	280	560	560	560	560	560	560
	Walnut Creek (Huntington Beach credits, assume 2018 COD)									500	500	500	500	500
K	Total estimated Approved / Under Construction Fossil Resources W LA			-	280	280	280	280	560	1,060	1,060	1,060	1,060	1,060
L	New RPS in W LA Basin													
M	New CHP in W LA Basin (SCE Base, proport to W LA, Yakov/ICF report)			27	41	55	68	89	109	130	151	171	178	184
N	Total net supply (I + J + K + L + M)			9,601	9,108	9,457	8,800	8,821	9,121	9,642	9,663	5,865	5,872	5,878
O	**Balance: Base Need (+ is surplus, - is deficiency) (N - H)**			**3,534**	**2,891**	**3,178**	**3,437**	**3,344**	**3,543**	**3,940**	**3,854**	**(57)**	**(169)**	**(278)**

2. Failure to include any amount of uncommitted preferred resources in determining future LCR need is inconsistent with California's loading order.

California's loading order, established first in the 2003 Energy Action Plan, and reiterated in subsequent Commission decisions,[59] requires the utilities to procure resources in a specific order:[60]

> "The 'loading order' established that the state, in meeting its energy needs, would invest first in energy efficiency and demand-side resources, followed by renewable resources, and only then in clean conventional electricity supply."[61]

However, the CAISO and the Utilities[62] caution against including incremental EE and DR savings to calculate LCR needs. SDG&E claims that:

> "Assigning a 'low' value to a resource such as EE or DR is not an indication of lack of support for that particular resource type, it merely recognizes the uncertainty in the availability of such resources and the CAISO's willingness to count such resource for purpose of satisfying LCR."[63]

Forecasts are by their very nature uncertain, and the longer the time frame, the greater the uncertainty.[64] But the CAISO discounts to zero the probability of uncommitted preferred resources materializing to meet a portion of LCR needs, asking that the Commission authorize SCE to procure conventional generation resources now to meet CAISO's forecasted LCR need nine to ten years in the future under the assumption that no incremental EE, DR or CHP will

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[59] *See e.g.* D.07-12-052, Finding of Fact No. 2 at 270 ("The primary principal guiding the Commission in its review of the plans is whether the IOUs are procuring preferred resources as set forth in the Energy Action Plan, in the order of energy efficiency, demand response, renewables, distributed generation and clean fossil-fuel resources;"); D.12-01-033 at 17-21 (all utility procurement must be consistent with the loading order; D.12-04-045 Finding of Fact No.4 at 206 ("The Commission remains committed to the Energy Action Plan's loading order whereby energy efficiency and demand response are the preferred means of meeting California's energy needs.")

[60] Although the loading order applies explicitly to utility procurement, there is no exception in the Public Utilities Code or any Commission decision for LCR procurement for local reliability needs on behalf of all benefitting customers.

[61] D.12-01-033 at 17, citing Energy Action Plan 2008 Update at 1.

[62] *See* Ex. SCE 2/Silsbee at 11:16-14:16; Ex. PG&E 1/Frazier-Hampton at 19:1-20:15; Ex. SDG&E 1 Anderson at 7:7-19.

[63] Ex. SDG&E 1/Anderson at 7:9-12.

[64] RT 79:16:20, ISO/Sparks.

materialize. CAISO's recommendation ignores the Commission's obligation to promote compliance with the loading order.

In fact, the CAISO's recommendation to meet LCR need first with conventional generation, because of the CAISO's claim that conventional generation is more reliable in reducing LCR need in a specific place, would eviscerate the loading order:

> "If the loading order is not the guide for planned resource additions, of what value is the policy? If the value of the policy is to 'fill in the gaps' that will arise in a utility's portfolio after central station generation resources are procured, then DR and EE are hardly preferred resources, but residual resources."[65]

The Commission should not allow uncertainties inherent in uncommitted demand side programs to diminish the value of those programs to zero for reducing LCR need. The fact that those programs are yet "uncommitted" (unfunded)[66] for the years in which LCR need is predicted is a byproduct of the current short-term funding cycles for those programs. If the Commission believes it is advisable to evaluate longer funding cycles, then it should consider that issue in related proceedings, including the EE and DR rulemakings. [67] In any case, it is unreasonable to assume that the Commission will not fund demand side programs for the years in which LCR need is predicted, given California's strong commitment to the loading order and the requirement of Public Utilities Code Section 454.5(b)(9)(C) . Nor is it reasonable to assume the programs will yield no savings that will reduce LCR need.

In addition to the uncertainty about the savings from demand side programs given the nature of how the programs are funded, SCE claims that it is difficult to allocate system wide savings to meet LCR need:

> "simple proration methods are unlikely to be reliable for assigning a location to uncommitted EE/ SCE is unaware of any reliable methods or data bases that would allow the Commission to calculate potential and achievable incremental EE at the bus bar level in a manner robust enough to plan for local area resource needs."[68]

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[65] Ex. EnerNOC 3/Tierney-Lloyd at III-1:27-31.

[66] Ex. SDG&E 1/Anderson at 7:16; RT 94:17-21 ISO/Sparks, RT 394:10-14 ISO/Millar.

[67] RT 904:16-25, DRA/Fagan.

[68] Ex.SCE 2/Silsbee at 12:13-16.

DRA recognizes that simple proration is unlikely to allocates system wide demand side resources in precisely the right amount to meet local need. Some locations are likely to achieve higher than system average savings, and others are likely to achieve lower than system average savings. However, it is not reasonable to assume that the savings in the LCR area will be zero, and DRA's method provides a sensible proxy. No other party offered a non-zero alternative.[69]

3. The Commission should not ignore the significant consequences of over procuring conventional generation to meet LCR need.

The CAISO claims that there are significant risks in incorporating uncommitted resources in the forecasts of LCR need, raising the specter of dire consequences ranging from rolling black outs[70] to the recall of the governor.[71] DRA acknowledges that reliable operation of the grid is an important state policy.[72] However, the reliability risk the CAISO cites is premised on the worst case scenario in that forecast year: the hottest day in ten years, combined with the outage of two generation or transmission elements.[73] The CAISO concedes, moreover, that for the past ten years there have been no forced outages on the limiting constraints identified for the LA Basin.[74] Finally, the CAISO implicitly assumes procurement policy inaction and/or failure in the intervening years.

The CAISO glosses over the consequences of authorizing conventional generation needed only in a worst case scenario that is unlikely to happen. Authorizing excess generation capacity makes it more difficult for preferred resources to compete.

> "By virtue of making a decision on fossil generation first, the Commission will be diminishing the need for preferred resources. [T]he need will be reduced because large-scale, central station generation additions are lumpy in nature [and] are added in advance of the anticipated short fall of capacity to meet demand needs…[F]or some period of time there will be a tolerated amount

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[69] *See e.g.,* RT 875:4-13; 890:1-891:16, PG&E/Frazier- Hampton.

[70] Ex.ISO-6/Millar at 18:12-20.

[71] RT 271:1-11, ISO/Sparks.

[72] *See e.g.* California Public Utilities Code Section 345.

[73] Ex. DRA 1/Fagan at 8:17-20; RT 119:13--120:18, ISO/Sparks.

[74] RT 120:2-28, ISO/Sparks.

of excess capacity….[that] will tend to reduce market pricing signals for both short-term capacity and energy. Short-term capacity and energy price signals will be the basis for compensating the resources that 'fill in the gaps,' which could be DR and EE."[75]

Moreover, the Commission authorizes funding for EE, DR, and distributed generation based on their cost-effectiveness.[76] The cost-effectiveness of EE, DR, and other preferred resources is greater when compared to the long-run avoided cost (or the cost of a new resource) as compared to the short run-avoided cost (whole sale energy prices, which for the most part reflect the cost of operating an existing resource).[77] Authorizing excess capacity to meet LCR needs can "crowd out" preferred resources that are no longer cost effective when compared to a surplus of capacity.[78]

The CAISO's witness Mr. Millar opined that:

"Energy efficiency goals have a great deal of value in reducing energy consumption, reducing the production of greenhouse gases, whether or not a generator has actually been built as backup insurance and having the capacity available."[79]

Mr. Millar's statement overlooks the fact that building a generator as "backup insurance" is a costly endeavor that makes it more difficult for demand side programs to compete in terms of their cost-effectiveness, thereby reducing the likelihood that they will be implemented and actually reduce energy consumption and the production of greenhouse gases.

C. Appropriate Assumptions Concerning Retirement of OTC Generation

The Clean Water Act section 316(b)[80] requires that the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. To implement the statute, in 2010, the SWRCB adopted the

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[75] Ex. EnerNOC 3/Tierney-Lloyd at III-2:8-18.

[76] *See e.g.* D.09-09-047 at 5, 6, 11; Public Utilities Code Section 454.5(b)(9)(C) (Investor- owned utilities (IOUs) must meet "unmet resource needs through all available energy efficiency and demand reduction resources that are *cost effective*, reliable, and feasible." (emphasis added)).

[77] *See e.g* D.06-06-063 at 44-45.

[78] Ex. DRA 3/Spencer at 3:12; Ex. DRA 1/Fagan at 22:9-16.

[79] RT 401:3-8, ISO/Millar.

[80] 33 U.S.C. § 1326(b).

"Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (Policy)."[81] The preferred method of compliance is to reduce a unit's water intake by 93% by replacing an existing unit with a newer, more efficient plant with a closed cycle, wet cooling system. If a generator is unable to employ this method, then, with the SWRCB's permission, it may retrofit existing units by improving the technology to reduce the intake of water by 83.7%. [82]

SCE's service territory includes six generating stations subject to this Policy: Ormond Beach and Mandalay Generating Stations are in the Big Creek/Ventura area; El Segundo, Alamitos, Redondo and Huntington Beach Generating stations are in the L. Basin Local Capacity Area.[83]

The CAISO's witness Mark Rothleder testified that:

> "By incorporating the OTC study results into the renewable integration studies, we found that there will be substantial needs for new, or repowered, generation resources in the Los Angeles Basin, Big Creek/Ventura and San Diego local areas, as early as 2018 when the existing OTC units must comply with the OTC requirements."[84]

Mr. Rothleder cited no authority for his assumption that existing generation must comply with OTC regulations by 2018, but his conclusion apparently includes the OTC units located in SDG&E's service territory. These, however, are subject to a separate proceeding – A.11-05-023 and their retirement dates are not relevant here.[85] SCE reiterated Mr. Rothleder's retirement date in arguing for flexibility in the timing of the need for LCR resources, notwithstanding that the date does not apply to the OTC plants in SCE's territory.[86]

Using the generators' implementation plans filed with the SWRCB, DRA witness David Siao summarized the retirement dates of the OTC plants in SCE's service territory. Mr. Siao testified that the earliest date an OTC plant's capacity would need to be replaced is 2015, with a

[81] Ex. DRA 2/ Siao at 2:4-14.

[82] Ex.DRA 2/ Siao at 3:1-11.

[83] Ex.DRA 2/ Siao at 4:3-7.

[84] Ex.ISO 4/ Rothleder at 7:13-17.

[85] *See e.g.*RT 111:18-19 (statement of ALJ Gamson).

[86] Ex. SCE 1/ Cushnie at 9:18-21.

possible extension to 2017.[87] By conflating the OTC retirement schedules in SDG&E's service territory with those in SCE, the CAISO seeks to persuade the Commission to authorize a greater amount of resources than may actually be necessary.

In his testimony summarizing the OTC compliance dates, Mr. Siao testified that the first units to retire will be Huntington Beach Units 3 and 4 in November 1, 2012 with a loss of 452 MW in capacity. The 500 MW Walnut Creek plant with a Commercial Operation date of May 1, 2013 will replace the units for a net gain of 48 MW.[88] The next unit to retire is El Segundo Units 1 and 2 in 2013. A 560 MW plant will replace these two units for a net loss of 110MW.[89] El Segundo is scheduled to retire on December 31, 2015.[90] NRG seeks to extend El Segundo Unit 4's compliance date to 2017.[91] Mandalay and Ormond Beach expect to meet their compliance deadlines of December 31, 2020.[92] AES has sought to extend the compliance date for Huntington Beach Units 1 and 2 to 2022[93] and may seek an additional extension of 1-2 years.[94] AES seeks to extend Alamitos' and Redondo Beach's compliance dates to 2026.[95] The earliest date an OTC plant would need to be replaced is 2015 for El Segundo Unit 4's 335 MW. This date may be extended based on NRG's additional information on repowering efforts.[96] If NRG's extension request is granted, then the retired plant would need to be replaced by 2017.

In responding to Mr. Siao's testimony regarding the generators' requests to extend OTC compliance dates, CAISO witness Mr. Millar urges the Commission not to take into account these extensions "without considerable evidence that the goals will in fact not be met."[97] CAISO's request for "considerable evidence" is undermined by its own conflating the OTC

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[87] Ex.DRA 2/ Siao at 8, 5:11-12.

[88] Ex.DRA 2/ Siao at 4: 10-13.

[89] Ex.DRA 2/ Siao at 4: 9-10.

[90] Ex.DRA 2/ Siao at 8.

[91] Ex.DRA 2/ Siao at 5:11-12.

[92] Ex.DRA 2/ Siao at 9.

[93] Ex.DRA 2/ Siao at 5:7.

[94] Ex.DRA 2/ Siao at 5: 8-10

[95] Ex.DRA 2/ Siao at 5:5

[96] Ex.DRA 9/ Siao Supplemental at 8.

[97] Ex.ISO 6/ Millar at 17:11-13.

retirement dates in SCE's territory with those in SDG&E's. Nevertheless, DRA shares the CAISO's commitment to "working with state agencies and the industry to achieve state policy goals, and to ensure that reliability is maintained through the transitions taking place to meet those goals."[98] But in simply reiterating the generators' requests to extend their OTC compliance deadlines, DRA does *not* endorse the requests. The generators' OTC implementation plans are their best estimates of OTC compliance. The Commission should consider these plans in determining the number of megawatts to replace retiring OTC plants.

Based on the information in Mr. Siao's testimony, DRA witness Mr. Fagan estimates that the OTC retirements in the L.A. Basin will result in the following cumulative 4,940 MW lost over ten years (Table 5):[99]

Table 5: DRA's estimated cumulative MW loss due to OTC retirements in the LA Basin

2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
787	452	1,122	1,122	1,122	1,122	1,122	4,940	4,940	4,940

Mr. Fagan testified that the deficiencies in the Big Creek/Ventura Local Area do not arise until 2020 (Table 6):[100]

Table 6: DRA's estimated cumulative MW loss due to OTC retirements in the Big Creek/Ventura area

2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
-	-	-	-	-	-	-	-	1,946	1,946	1,946

While the CAISO does not dispute the compliance deadlines in the generating units' compliance letters and summarized in Mr. Siao's testimony, it does depend on a number of "worst case" assumptions concerning transmission system events, weather and load, and the set of supply and demand resources that will be in place in 2021.[101] As Mr. Fagan observes "although it is possible that a part of the OTC resource need shown by CAISO in its primary modeling run may occur in 2021, . . ., neither CAISO nor SCE should be obligated to procure for

[98] Ex.ISO 6/ Millar at 17:5-7.

[99] Ex.DRA 1 A 2/ Fagan at 3:6-8 and 18.

[100] Ex.DRA 1/ Fagan at 19.

[101] Ex.DRA 1/ Fagan at 23.

such potential occurrences seven to eight years in advance, given the wide range of resource options with lower lead times for procurement." [102]

D. Transmission and Other Means of Mitigation

1. Transmission

DRA[103], CAISO[104] and SCE[105] all recognize that future transmission upgrades could reduce the future LCR needs. Citing Exhibit ISO 1/Sparks, Table 2 at 7 Mr. Fagan explained that:

> "First, CAISO presents two sets of LCR needs for the overall LA Basin that vary depending on which critical transmission contingency is binding. The less limiting transmission contingency leads to overall LA Basin needs that are lower by more than 2,500 MW in the trajectory case, for example. This result illustrates that reinforcement of underlying transmission system elements, along with use of operational procedures to wring the most value from critically-placed and critically-loaded 500/230 kV transformers will lower LCR need.
>
> Second, in the Supplemental Testimony of Mr. Sparks, CAISO presents results of an updated analysis that included a recently accelerated transmission reinforcement project (Del Amo – Ellis 230 kV line loop-in project). The presence of this transmission reinforcement in the model contributed to lower LCR need in the LA Basin area."[106]

Despite the potential for future transmission upgrades to reduce LCR need, there is currently no clear process for ensuring the identification and implementation of all cost-effective transmission (and distribution) solutions prior to the procurement of additional LCR resources. For example, the CAISO assumed in its OTC studies the completion of potential distribution upgrade at the Rancho Vista substation that would allow the transfer of approximately 600 MW from the Mira Loma substation and reduce overall LA Basin need by 2000 to 3000 MW.[107] The CAISO apparently discussed with SCE the potential distribution

[102] Ex. DRA 1/ Fagan at 23:6-11.

[103] Ex. DRA 1/Fagan at 4:7-24.

[104] RT 116:14-19, ISO/Sparks.

[105] Ex. SCE 1/Cabbell at 8:19-9:14; RT 778:1-14, SCE/Cabbell.

[106] Ex. DRA 1/Fagan at 4:10-21.

[107] RT 85:23-86:16, ISO/Sparks.

upgrade that would transfer approximately 600 MW from the Mira Loma substation, and Mr. Sparks testified that it was part of SCE's distribution plan.[108]

However, Mr. Sparks later revised his testimony,[109] and SCE witness Dana Cabbell testified that the 600 MW transfer proposal was unproven and may not be cost-effective.[110] Ms. Cabbell testified on cross examination that the 600 MW transfer proposal was a possibility that had not yet been studied, and which would require "a lot of further investigation to …design the system…and obviously the cost and feasibility of it."[111] While the ultimate effectiveness of the 600 MW transfer proposal is yet uncertain, the option deserves further focused study as part of an overall effort to reduce LCR need. The miscommunication between the CAISO and SCE on a distribution system improvement that could reduce LCR need by 2000 to 3000 MW illustrates that the process for identifying and evaluating the viability and cost-effectiveness of such options has room for improvement.

It remains unclear whether additional cost-effective transmission solutions are available that can reduce LCR need. Mr. Sparks testified that the CAISO evaluated transmission mitigation measures "on a high level in order to maintain local reliability,"[112] but acknowledged that the evaluation was necessarily limited.

> "The ISO engineering staff has expertise in running power flow analysis, stability analysis, general transmission planning type skills, but we do not have detailed engineering staff. We rely on the transmission owners to develop feasibility and cost estimates of transmission upgrades.
>
> So if we were going to look at alternatives, we would need to get them involved to help us determine the feasibility of ideas that we were throwing out, even have them come up with ideas themselves and ultimately come up with, once it is determined to be feasible, cost estimates and schedules, that sort of thing. We didn't even engage the transmission owners at this point."[113]

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[108] RT 84:9-13, ISO/Sparks.

[109] RT 264:20-265:14, ISO/Sparks.

[110] Ex. SCE 2/Cabbell at 19: 1.

[111] RT 782:3-17, SCE/Cabbell.

[112] Ex. ISO 1/Sparks at 5:15-16.

[113] RT 103:26-104:13, ISO/Sparks. Mr. Sparks was unable to state, for example, whether there was enough room at the Antelope substation for another transformer. RT 173:8-12.

Mr. Sparks' testimony illustrates that more work remains to identify cost-effective transmission (and distribution solutions) that can reduce LCR need.

Mr. Fagan explained the difference between the additional information about potential transmission upgrades that DRA recommends[114] and the ongoing work by SCE[115] and the CAISO. Mr. Fagan pointed out that the current RA construct in which other transmission analyses take place is focused on the near term rather than five years or longer into the future and noted that the information DRA recommends would directly compare the cost of system upgrades to the cost of resource acquisition.[116]

Mr. Millar testified "we believe we have identified…the low-hanging fruit where transmission reinforcement was a viable way to reduce local capacity requirements"[117] However, given the miscommunication and lack of clarity between SCE and the CAISO, it is uncertain whether all the low-hanging fruit has actually been captured, or whether viable transmission upgrades that could lower LCR need will actually be pursued. The Commission should not authorize additional LCR in the amount recommended by CAISO and supported by SCE without ensuring that cost-effective transmission and distribution upgrades have been thoroughly explored and implemented.[118]

The Commission should direct SCE to work with the CAISO, with all due speed, to identify, analyze and ultimately implement additional cost-effective transmission solutions that will reduce LCR need. DRA recommends that the Commission direct SCE to identify and complete a comprehensive analysis of all reasonable alternatives and present such analysis to the Commission no later than the time of the commencement of the 2014 LTPP proceeding.[119]

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[114] Ex. DRA 6/Fagan at 24:1-10.

[115] RT 777:1-779:10, SCE/Cabbell (explaining that both the CAISO and SCE examine possible transmission upgrades).

[116] RT 908:24-910:3, DRA/Fagan.

[117] RT 421:19-23, ISO/Sparks.

[118] Ex .CEERT 2 at 3:26-4:3. (recommending that the Commission place on this record and/or conduct new studies to evaluate cost effective transmission/distribution solutions that can reduce LCR need.)

[119] However, if the Commission authorizes additional LCR beyond the amounts recommended by DRA, such analysis should be considered by the Commission prior to the 2014 LTPP.

2. Coordination with the Los Angeles Department of Water and Power (LADWP)

Mr. Fagan observed that the LTPP proceeding is the correct venue to determine how improved balancing area coordination within the LA Basin could lead to total lower LCR needs for both the CAISO and LADWP control areas.[120] The CAISO claims that the potential for improved coordination to reduce LCR needs is unlikely to yield much benefit.[121] However, it does not appear that potential coordination between LADWP and CAISO has been adequately pursued, despite the possibility that such coordination may reduce LCR needs in some beneficial amount.[122] The Commission should request that the CAISO report back within a year from the issuance of its decision on local reliability issues regarding possible options to reduce LCR need as a result of increased coordination with LADWP.[123]

III. DETERMINATION OF LCR NEED SPECIFIC TO LA BASIN AND BIG CREEK/VENTURA AREA

A. LA Basin

As discussed above, DRA recommends that the Commission authorize SCE to procure no more than 169 MW for the West LA Basin for 2021, and no more than 278 MW for 2022. Notwithstanding questions about the CAISO's assumptions[124] and its acknowledgement that uncertainties create a risk of over procurement, [125] SCE claims that the CAISO's range of new resources need for the West LA Basin is reasonable in light of the difficulty in procuring sites for generation in the LA basin.[126] However, the existence of the current OTC sites, coupled with the greatly reduced LCR need that exists when considering preferred resources, makes it unnecessary to begin procuring to meet new resource needs in the range recommended by the CAISO and supported by SCE.

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[120] Ex. DRA 1/Fagan at 5:1-5.

[121] RT 170: 16-171:24 ISO/Sparks (expressing skepticism that improved coordination would reduce LCR given existing constraint, but unclear on extent to which all options had been explored).

[122] RT 899:18-901:1, DRA/Fagan.

[123] Ex.DRA 6/Fagan, Attachment A at 3.

[124] Ex. SCE 1/Minick at 6:10-11.

[125] SCE 1/Cushnie at 2:6-8.

[126] Ex. SCE 2/Silsbee at 12:18-15:7.

B. Big Creek/Ventura Area

As discussed above, DRA recommends that the Commission find no current new resource need for the Big/Creek Ventura area, and that the Commission revisit the issue of LCR need in the Big Creek/Ventura area during the 2014 LTPP. SCE agrees that there is no current need to procure for LCR need in the Big Creek/Ventura area, citing the CAISO's lower finding of need,[127] greater availability of sites,[128] and uncertainty regarding the plans of existing OTC generators.[129]

IV. PROCUREMENT OF LCR RESOURCES AND INCORPORATION OF THE PREFERRED LOADING ORDER IN LCR PROCUREMENT

SCE espouses overall support for the CAISO OTC study, at least the portion of the study related to the LA Basin. SCE nevertheless acknowledges the uncertainty of the CAISO's predicted LCR need and risk associated with long-term commitments. SCE therefore requests that the Commission afford SCE significant flexibility in procuring LCR need for the LA Basin:

> "The Commission should avoid making long-term commitments to new generation that could subsequently be rendered significantly less valuable by changed circumstances. The Commission should authorize procurement up to the range identified by CAISO, but not require a specific amount of MWs within a specific timeframe."[130]

SCE Exhibits 1[131] and 2[132] stress SCE's desire for flexibility in the procurement process, but offer little in the way of details about how the process would work, other than to state that SCE would submit proposed power purchase agreements (PPAs) to the Commission for approval.[133]

SCE sketched a bare bones process for procurement of LCR resources and incorporation of the preferred loading order for the first time in the testimony of Mr. Cushnie during cross

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[127] Ex. SCE 1/Minick at 10:15-16.

[128] Ex. SCE 1/Minick at 11:8-11.

[129] Ex. SCE 1/Minick at 10:23-11:7.

[130] Ex. SCE 1/Silsbee at 4:18-21 (emphasis added).

[131] Ex. SCE 1/Minick at 5:9-21.

[132] Ex. SCE 2/Cushnie at 7:8-16.

[133] Ex. SCE 2/Cushnie at 4:9-13.

examination.[134] Mr. Cushnie explained that the process may consist of a Request for Offers (RFO) for supply- side resources, and may include negotiations for cost-of-service contracts before or during the RFO process, while at the same time SCE will consider in a parallel process how preferred resources can reduce load.[135] The details of the process and how it would work were vague, but Mr. Cushnie was clear on the fact that it would not include stakeholder participation until SCE submitted its application to the Commission seeking approval of its proposed PPAs.[136] At that point, parties could comment on the economics of SCE's proposed projects as well as whether they are consistent with the State's preferred loading order.

DRA would not oppose SCE's process if the Commission authorized LCR procurement in an amount no greater than DRA's recommendation of 169 MW for 2021 and 278 MW for 2022. If the Commission authorized LCR procurement in an amount no greater than DRA's recommendation of 169 MW for 2021 and 278 MW for 2022, then it would be reasonable to allow SCE's flexibility in the procurement process. That is because DRA's recommendations already take into account the significant contributions of preferred resources. However, if the Commission authorizes SCE to procure amounts greater than DRA recommends, based on an analysis that does not include preferred resources as DRA forecasts, the flexibility requested by SCE is inappropriate because it is unclear how preferred resources would be addressed in the procurement process, thus jeopardizing compliance with the loading order. Mere assurances that the loading order will be followed do not necessarily result in a viable process for doing so, and more stakeholder input and Commission review is necessary. If the Commission authorizes a greater amount of LCR procurement, then stakeholders should be allowed to comment on SCE's economic studies evaluating preferred resources before SCE submits its proposed PPA applications to the Commission.

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[134] RT 611:27 - 613:6.

[135] RT 607: 12-19, SCE/Cushnie "So what we would have to do is make an assumption as to the economics and the viability of demand reduction programs. And to the extent that we can get comfort that the economics and the viability are there, we can then do studies to see if that can reduce the LCR need to meet with supply side resources."

[136] RT 610:4-23, SCE/Cushnie and 1077:19-20, SCE/Silsbee.

A. Incorporation of the Preferred Loading Order in LCR Procurement

The best way to incorporate preferred resources in the loading order into LCR procurement is to authorize such procurement assuming that uncommitted EE, DR and CHP will actually materialize. This can be done by using DRA's recommended new resource need for the West LA Basin of 169 MW for 2021 and 278 MW for 2022, or by using the CAISO's Sensitivity Analysis and adding in demand response that can be reasonably expected to meet LCR need. The LTPP process is a planning process, and planning for future preferred resources is an important component of planning for future energy needs. If the Commission does not plan to meet LCR needs using preferred resources, it is unlikely to happen. In that situation, not only would ratepayers be paying for demand-side programs without actually realizing the benefits in the procurement process, but California would also miss out on the opportunity to utilize all of its available resources

B. Other Commission Policies and Consideration Affecting LCR Procurement

1. The Commission should ensure that rates are just and reasonable, a result that will not be achieved if rates include unnecessary LCR resources.

Public Utilities Code Section 451 requires that:

> "All charges demanded or received by any public utility ... shall be just and reasonable.
> Every unjust or unreasonable charge demanded or received for such product or commodity or service is unlawful."

The CAISO suggests that the Commission should authorize conventional generation to serve as "backup insurance" while also authorizing preferred resources to provide energy without emitting greenhouse gases.[137] This approach would require ratepayers to fund both costly fossil fuel generation and preferred resources.[138] The result would be rates that are unreasonably high, and the Commission should reject this costly "belt and suspenders" approach that implies that ratepayers have pockets of unlimited depth.

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[137] RT 401:3-8, ISO/Sparks.

[138] SCE's DR budget for 2012-2014 is $196,338,052 .D.12-04-045 at 198. SCE's EE budget for 2010-2012 is $1.228 billion. D.09-09-047, Ordering Paragraph 3(b) at 365.

The CAISO and the Commission have different and complementary roles in implementing California's energy policy. The CAISO's primary mission to ensure reliable operation of the transmission system,[139] while the Commission must balance reliability with compliance with the loading order and rates that are just and reasonable.[140] The Commission, consistent with its obligation to ensure compliance with the loading order and rates that are just and reasonable, should reject the suggestion that meeting LCR needs with conventional generation as "back up insurance" is necessary or prudent.

2. The Commission should direct SCE to implement preferred resource programs in a manner that will effectively reduce LCR need.

Rather than authorizing SCE to procure to meet LCR need on the assumption that preferred resources will not materialize, the Commission should assume those resources will meet LCR need, and direct SCE to develop its preferred resource programs in a manner that will produce those results. The Commission should direct SCE to work with CAISO to determine a priority-ordered listing of the most electrically beneficial locations for preferred resource deployment (supply or demand side) to maximize such resources' ability to reduce LCR need. Such a listing should use a reasonable level of electrical aggregation, such as at minimum the LCR sub-area, or if possible, using a finer electrical-location granularity such as substations. The intent of such a determination would be to help identify all of the best locations "downstream" of certain substations or LCR sub-areas for preferred resource installation, so that SCE programs to secure preferred resources could potentially be targeted first at these better locations.

a) Demand Response

EnerNOC witness Ms. Tierney-Lloyd explained that CAISO's OTC study excluded savings from DR programs that could reduce LCR needs.[141] EnerNOC witness Mr. Hoffman

[139] Public Utilities Code Section 345 (DRA notes that Section 345.5 requires the CAISO to conduct its operations consistent with applicable state and federal laws.)

[140] Public Utilities Code Sections 451(just and reasonable rates) and 454.5(b)(9)(C) (compliance with the loading order).

[141] Ex. EnerNOC 1/Tierney-Lloyd at II-2:11-18.

described the successful use of DR programs in other markets.[142] Yet even the CAISO's Sensitivity Analysis assumed no uncommitted DR.

Both the CAISO and SCE expressed doubts that DR could effectively reduce LCR needs because of concerns regarding the timeliness, location, durability[143] of DR's response[144] as well as doubts about the willingness of customers to participate.[145] These concerns are valid, but rather than assuming DR cannot meet LCR need, SCE should work with its customers, the CAISO, and the Commission, and to remove these barriers. In particular, SCE should develop the appropriate DR communication infrastructure and tariffs that will encourage customer participation in order to reduce peak demand on the 10-15 hottest days, so that peak shaving will permit other resources to respond quickly in the event of a contingency.[146]

3. The Commission should not authorize the wide range of procurement authority SCE requests, because it would promote market uncertainty.

Granting SCE the wide range of procurement authority it seeks—up to 3,741 MW, but with no lower limit,[147] would not promote market stability. The Commission need look no further than the history of PG&E's proposed Oakley Project to see the problems that could result with giving SCE the "blank check" it seeks in to fill remaining LCR need.

The Commission in D.07-12-012 authorized PG&E to procure between 800 to 1200 MW based on the 2007 California Energy Demand forecast.[148] Three years later, in response to PG&E's application seeking approval of the Oakley Project (for utility-owned generation) and several PPAs, the Commission decreased PG&E's procurement authority to a lower range of 950 to 1000 MW.[149] The Commission explained that the economy has deteriorated and as a result

[142] Ex. EnerNOC 2/Hoffman at II-1—II-9.

[143] Durability refers to the amount of time the DR resource is available.

[144] RT 350:11-27, ISO/Millar; RT 646:16-647:11, SCE/Cushnie; RT 1068:28-1069:5, SCE/Silsbee.

[145] RT 1068:7-1072:8, SCE/Silsbee.

[146] RT 914:24-915:26, DRA/Fagan.

[147] Ex. SCE 2/Cushnie at 9:29.

[148] D.07-12-052, Ordering Paragraph 4 at 300.

[149] D.10-07-045, Conclusion of Law 4 at 53. This reduction was subject to certain exceptions.

the load forecast has decreased.[150] The Commission therefore approved the PPAs but declined to approve the Oakley Project, since its approval would have exceeded the reduced load forecast. One of the concurring opinions noted that although the Oakley Project was no longer needed, its rejection sent a "troubling" message to the investment community and developers, given the facts that the project had been selected through a competitive solicitation and met all the requirements, yet was still rejected.[151]

The Commission should prevent similar undesirable outcomes that might flow from granting SCE authority ranging up to 3,741 MW that would subsequently not be needed. Rather than granting such a wide range of procurement authority, and allowing SCE the discretion to determine how much is really needed, the Commission should authorize the amount DRA recommends, and reevaluate the need for more authority in the 2014 LTPP. This will help ensure market stability by sending the correct signal to the market that the Commission has determined need that will not abruptly decrease later.

C. If A Need is Determined, How the Commission Should Direct LCR Need To Be Met?

D. Appropriate Method(s) of Procurement

If the Commission limits SCE's authority to procure LCR resources up to 169 MW for 2021 and up to 278 MW for 2022, then DRA does not oppose SCE's request for flexibility in procuring to meet this amount of LCR need. That is because granting the procurement authority DRA recommends would reflect reasonable assumptions regarding preferred resources. However, if the Commission authorizes SCE to procure more than the amount DRA recommends--in essence disregarding the forecasted amounts of preferred resources--then the Commission should develop a more robust process for meeting LCR need consistent with the loading order.

Developing such a process and the appropriate methods of procurement was discussed at the Commission's September 7, 2012 joint energy storage and LTPP workshop and is the subject of a separate ruling. The topic is complex and will likely require significant time to resolve all the issues.

[150] D.10-07-045 at 5.

[151] D.10-07-045, Concurrence of Commissioner John Bohn at 1.

E. Timing of Procurement

The CAISO and SCE claim that the process for LCR procurement must start now because it of the time it takes conventional generation to come on line.[152] However, the urgency conveyed by the CAISO and SCE is overstated because using existing sites to develop repowered generation that complies with OTC compliance requirements would likely take less than seven years.[153] Mr. Fagan explains that because the transmission infrastructure is in place, and replacement generation could use existing air permits, the use of existing generation sites for repowered generation is akin to having an "ace in the hole."[154]

Furthermore, the lead time for preferred resources to come on line is significantly less than that required for conventional generation.[155] Because of the nature of the programs and their funding cycles, 2021 preferred resources will not be funded in the Commission's decision on local reliability issues.[156] However, that does not mean that the preferred resources will not be available. Rather, it provides ample opportunity to ensure the development of preferred resources to meet residual LCR need as the Commission determines future aspects of program design and funding cycles.

The CAISO witness Mr. Millar states that "not moving forward now …could result in viable resources falling by the wayside …simply because there isn't enough time to proceed with that alternative."[157] In fact, accepting the CAISO's recommendation to procure now for 2021 LCR need without accounting for uncommitted preferred resources, or acknowledging the availability of existing sites if necessary, would yield a worst result: LCR "need" will be met only with conventional generation in excess of actual requirements.

[152] Ex. ISO 6/Millar at 19:17-20; Ex. SCE 2/Silsbee at 11:12-14.

[153] RT 916:20-917:3, 917:17-22, DRA/Fagan.

[154] RT 924:9-11, DRA/Fagan.

[155] *See e.g.,* RT 1091:9-1092:20, SCE/Silsbee.

[156] RT 904:16-25, DRA/Fagan.

[157] RT 372:2-6, ISO/Millar.

V. INCORPORATION OF FLEXIBLE CAPACITY ATTRIBUTES IN LCR PROCUREMENT

A. If A Need Is Determined, Should Flexible Capacity Attributes Be Incorporated Into Procurement?

The Commission has no authorized definition of flexibility.[158] Stakeholders are currently discussing the issue in this proceeding as well as in the RA proceeding, R.11-10-023. The Commission should allow, but not require, SCE to procure resources to meet its LCR need that are flexible, and should evaluate the value of the flexibility, along with all other aspects of the application that SCE submits for Commission approval.

B. Additional Rules, Not Already Covered By Resource Adequacy (RA) Rules, To Govern LCR Procurement

RA rules only apply to year-ahead procurement. With this ground-breaking LCR proceeding to examine and grant authorization for a ten-year time frame, the same procurement rules which apply to long-term system procurement should apply to long-term procurement for local areas. The local areas are already granted a more conservative 1-in-10 load factor to account for their unique situation relative to the greater system need. There is no justification to impose further restrictions, such as enhanced discounting of preferred resources.

VI. COST ALLOCATION MECHANISM (CAM)

A. Proposed Allocation of Costs of Needed LCR Resources

The net capacity costs[159] of all LCR procurement should be allocated to all benefitting customers in SCE's service territory, including SCE's bundled customers, direct access (DA) customers and Community Choice Aggregation (CCA) customers.[160] "Since LCR resources would provide reliability benefits to all customers, the net capacity costs should similarly be allocated to all customers."[161]

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[158] Ex. DRA 3/Spencer at 12:30-13:3.

[159] Net capacity costs are calculated by subtracting the energy and ancillary services value of the resource from the total costs paid by the electrical corporation pursuant to a contract with a third party or the annual revenue requirement for the resource if the electrical corporation directly owns the resource.

[160] Ex. DRA 5/Ciupagea at 1:15-18; *see also* Ex. SCE 1/Cushnie at 26:1-4; Ex. TURN 1/Woodruff at 23:28-24:3; Ex. SDG&E 1/Anderson at 9:6-15.

[161] Ex. DRA 5/Ciupagea at 1:15-18.

Allocating the cost of resources that will enhance system reliability is consistent with Public Utilities Code Section 365.1(c) (2) (A), which provides that if the Commission determines that generation resources "are needed to meet system or local reliability needs for the benefit of all customers in the electrical corporation's distribution service territory," then:

> [T]he net capacity costs of those generation resources are allocated on a fully nonbypassable basis consistent with departing load provisions as determined by the commission, to all of the following:
> (i) Bundled service customers of the electrical corporation.
> (ii) Customers that purchase electricity through a direct transaction with other providers.
> (iii) Customers of community choice aggregators.[162]

In contrast, the Alliance for Retail Energy Markets (AReM), the Direct Access Customer Coalition (DACC), and Marin Energy Authority (MEA) are mistaken in linking system and local area reliability needs to bundled service customers' load. Procuring new generation to meet a Commission-approved need for new system and local area reliability resources is determined by the Commission in a transparent manner in the current long term procurement plan (LTPP) proceeding. The Commission will authorize any necessary procurement based on calculations that reflect a forecast of the entire system's load of all customers, including DA and CCA customers, and not just bundled customers. Because benefits from system and local reliability flow to all customers, the net capacity costs should be allocated to all customers. Furthermore, DRA agrees with SCE's arguments that "AReM's proposal incorrectly assumes that existing load has a priority right to existing generation" and that "AReM's proposal fails to recognize that the electric grid is interconnected [and] [i]ndividual customers are not targeted for involuntary load shedding on the basis of their contributions to meeting system and local area reliability."[163]

B. Should CAM Be Modified At This Time?

The Commission could authorize procurement to meet LCR needs using the existing CAM. However, DRA supports exploring improvements to this existing CAM, especially given the fact that LCR resources would not be needed until 2021. DRA therefore supports SDG&E's proposal to convene workshops to explore possible modifications to the net capacity cost

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[162] Public Utilities Code Section 365.1(c) (2) (A).

[163] Ex. SCE 2/Cushnie at 27-29.

calculation.[164] To the extent that market revenues can be more accurately and transparently estimated using public data, it would be beneficial to explore, in workshops, the reduction of capacity costs for all parties.

DRA also supports SDG&E's proposal that the Commission should focus in the near term on the development of a "benefits test," which could provide criteria for authorizing CAM procurement. DRA therefore proposes the Commission convene workshops to explore possible methodologies for the development of a "benefits test."

C. Should Load Serving Entities (LSEs) Be Able To Opt Out Of CAM?

The Commission has found the concept of an opt-out mechanism "appealing" in the context of implementing a viable enforcement program or mechanism to ensure that any LSE opt-out is conditional on demonstrating that it is fully resourced with new generation for the 10-year time frame.[165] However, AReM/DACC/MEA propose three types of opt-out, all of which would allow an entity to opt out using "5-year contract term or project life."[166] Five years is not long enough to allow the development of new resources,[167] so there is still not an appealing opt out mechanism before the Commission for review.

VII. OTHER ISSUES

A. SCE Capital Structure Proposal

SCE requests authorization to adjust its authorized capital structure if procurement of new LCR generation would impair its credit worthiness.[168] SCE explains that:

> "Debt equivalence arises from long-term purchased power contracts and other long –term financial commitments not included as debt on the balance sheet. The capacity cost components of purchased power contracts are considered to be 'debt equivalents' by rating agencies because the payments required under a purchased power contract are fixed obligations that cannot be avoided without defaulting on (breaching) the contract."[169]

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[164] Ex. SDG&E 1 at 10.

[165] D.06-07-029 at 35.

[166] Ex. AReM/DACC/MEA 1 at 55:20.

[167] RT 766:11-767:11, TURN/Woodruff; RT 557:10-558:9, PG&E/Williams.

[168] Ex. SCE 1/Hunt at 27:8-9.

[169] Ex. SCE 1/Hunt, Appendix B at 1:1-6. Mr. Hunt explained during cross examination that one of the

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SCE requests that "the Commission grant SCE the opportunity to file an application to adjust its authorized capital structure should new or renewed PPAs (signed after Commission approval of this proposal) result in an increase in [debt equivalence] that causes a significant adverse impact on SCE's credit ratios."[170] SCE envisions that it might apply for a change in its capital structure at the same time it files its PPA to meet LCR need for Commission approval, or "most likely," it would file a separate application.[171]

Currently, issues related to SCE's capital structure are considered in the cost of capital proceeding. SCE filed A.12-04-015 this year recommending an authorized capital structure for the next three years.[172] DRA opposes SCE's request to consider debt equivalence outside its cost of capital application. Debt equivalence is one of many issues that the Commission considers in establishing SCE's cost of capital and its capital structure.[173]

> "Debt equivalence is only one of the many components that are used to establish SCE's authorized cost of capital in the Cost of Capital Proceeding. The authorized cost of capital is computed based on weighted average cost of long-term debt, common equity and preferred equity. As the market conditions change (such as risk-free rate, market risk premium, liquidity of funds, beta, growth rate projections, etc.), the assumptions that go into computation of cost of debt and equity will also change, which will affect SCE's cost of capital. Therefore, it is inappropriate to look at the impact of debt equivalence on SCE's cost of capital in isolation without considering all of the other components. The appropriate venue to consider the potential impact of new or renewed PPAs on SCE's debt equivalence is the Cost of Capital proceeding, not a separate application."[174]

DRA opposes SCE's request to separately apply for a change in its capital structure outside the cost of capital proceeding, but agrees that it is important to maintain and enhance SCE's creditworthiness. To the extent that rating agencies consider PPAs a source of debt

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credit rating agencies, Standard and Poor, imputes a capacity cost even in contracts that are for energy only. RT 842:8-11, SCE/Hunt.

[170] Ex. SCE 1/Hunt at 28:8-9.

[171] RT 834:7-13, SCE/Hunt.

[172] RT 845:6-15, SCE/Hunt. Dr. Hunt explained that SCE is requesting continuation of its current three-year cost of capital cycle, which if continued, would mean that SCE's next cost of capital application would be filed in April 2015.

[173] *See e.g.*,.D.05-12-043 at 8, (affirming that potential debt equivalence impacts would be assessed in the cost of capital proceeding "on a case-by-case basis along with other financial, regulatory, and operational risks in setting a balanced capital structure and fair ROE.")

[174] DRA 8/Lasko at 2:9-18.

equivalence,[175] and to the extent that the debt equivalence would have an impact on SCE's creditworthiness, the Commission should minimize the amount of LCR procurement that SCE is authorized to undertake. The Commission should also encourage the use of preferred resources to reduce or meet LCR need, because those resources generally do not result in debt equivalence from any rating agency.[176]

B. Coordination of Overlapping Issues Between R.12-03-014 (LTPP), R.11-10-023 (RA), and A.11-05-023

DRA recommends that the Commission incorporate any definition of flexible capacity developed in A.11-10-023 into its evaluation of LCR procurement in this process. As explained above, DRA recommends at this time that SCE be allowed, but not required, to procure flexible capacity to meet residual LCR need.

DRA recommends that the Commission incorporate uncommitted preferred resources in its determination of LCR need for both SCE and SDG&E customers. Incorporating uncommitted preferred resources for both SCE and SDG&E would be consistent with the Commission's guidance in D.07-12-052, noting that "[p]arties in favor of uniform planning criteria identify numerous benefits, but one in particular resonates with the Commission: the ability of the Commission to oversee prudent procurement choices."[177] Using different assumptions for LCR need for SCE and SDG&E, because of the procedural anomaly in which SDG&E's LCR need is determined outside the LTPP process would make little sense, and would undermine confidence in the Commission commitment and ability to complete long-term resource plans.

C. SCE Statewide Cost Allocation Proposal

SCE requests that "to the extent that LCR resources provide flexibility benefits (i.e. integration services for intermittent resources), SCE is interested in seeking a broader allocation

[175] Dr. Hunt explained that two of the rating agencies, Moody's and Fitch, are more likely to treat capacity payments in PPAs as operating expenses that would not impact debt equivalence or credit worthiness. RT 836:14-27.

[176] RT 840:27-842:3, SCE/Hunt (testifying during cross examination that EE, DR, DR would not result in debt equivalence, but CHP might, depending on the form of the contract.)

[177] D.07-12-052 at 29.

from all CPUC customers benefitting from the increased flexible capacity."[178] Notwithstanding SCE's "interest" in seeking a broader allocation of costs from all CPUC jurisdictional customers, Mr. Cushnie clarified during cross examination that SCE was not making a specific proposal for allocating costs of flexible capacity to all CPUC customers benefitting from increased flexibility.[179] Instead, Mr. Cushnie described a hypothetical in which SCE might seek recovery from customers other those in its own service territory. Mr. Cushnie explained that if the Commission ordered SCE to procure LCR resources with more flexible attributes than the resources that SCE submitted in its application, if the flexible resources benefitted all system customers, and if the costs were more than a "few million dollars" higher than the resources SCE submitted, SCE might seek to allocate the costs among all CPUC jurisdictional customers.[180]

It is not necessary for the Commission to rule on the issue of cost recovery for one utility from the customers of other utilities to procure flexible system resources. The Commission has not ordered SCE to procure resources as described in SCE's hypothetical, and SCE has no pending proposal for cost recovery. It is therefore unnecessary to consider the issue now.

Courts and other decision making entities are not inclined to issue decisions in the absence of a real dispute, rather than the hypothetical possibility of a dispute. Thus,

> "the legal issues posed must be framed with sufficient concreteness and immediacy so that the court can render a conclusive and definitive judgment rather than a purely advisory opinion based on hypothetical facts or speculative future events."[181]

The Commission explained in D.97-09-058 that it in order to conserve scarce decision making resources it generally "does not issue advisory opinions in the absence of a case or controversy."[182] This Commission should avoid ruling on SCE's statewide cost allocation

[178] Ex. SCE 1/Cushnie at 26:8-11; *see also* Ex. SCE 2/Cushnie at 5:27-6:3.

[179] RT 712:16-23, SCE/Cushnie.

[180] RT 713:2-28, SCE/Cushnie.

[181] *Hayward Area Planning Assoc., Inc.* (1999) 72 Cal. App. 4th 95, 103; *see also* A*bbott Laboratories v. Gardner (1967)* 387 U.S. 136, 148-149 (General test for ripeness is that there must be a substantial controversy between parties having adverse legal interests of sufficient immediacy and reality to warrant the issuance of relief.).

[182] *Application of Women's Energy, Inc. for an Order Declaring Women's Energy, Inc. not subject to the Commission's jurisdiction*, 75 CPUC 2d 624, 625 (1997).

"proposal" in the absence of an actual proposal or even the existence of any of the conditions described in SCE's hypothetical.

D. CAISO Backstop Procurement Authority to Avoid Violating Federal Reliability Requirements

DRA has no comments on this issue now, but may respond to the opening comments of other parties.

E. Energy Storage

DRA has no comments on this issue now, but may respond to the opening comments of other parties.

VIII. CONCLUSION

The CAISO claims that relying on preferred resources as recommended by DRA and other parties would threaten reliable operation of the electric system. The Commission should reject this false premise. Expecting preferred resources to reduce LCR need, and preparing to achieve that goal in this planning process can serve California's interests in a sustainable energy future without compromising reliability. Planning so that preferred resources will reduce LCR need would also allow ratepayers to receive the full benefits of the preferred resource programs they fund and avoid the risks of market uncertainty and unreasonable rates associated with over procurement. DRA recommends that the Commission take this opportunity plan for a future in which preferred resources effectively reduce future resource need in LCR areas.

Respectfully submitted,

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