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.	)))	R.12-03-014 (Filed March 22, 2012)

CALIFORNIA ENVIRONMENTAL JUSTICE ALLIANCE'S

TRACK 4 OPENING BRIEF

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TABLE OF CONTENTS

SB_GT&S_0140704

TABLE OF AUTHORITIES

Statutes

Cases

I. SUMMARY OF RECOMMENDATIONS

***RECOMMENDATION 1*:** The California Environmental Justice Alliance (CEJA) urges the Commission to find that Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E) have no need for additional procurement to meet their long-term local capacity requirements (LCR) needs at this time. CEJA provides the following support for this recommendation:

- The purported need for new long-term procurement is based on a highly improbable scenario in which three import pathways to the SONGS study area are unavailable on the hottest day in ten years, to which CAISO adds a 2.5% reserve margin not required by NERC reliability standards, and refuses to allow for controlled load shedding under SDG&E's WECC-approved Special Protection Scheme. Reliance on increasingly dire snapshots that well exceed anything required by NERC to justify long-term resource procurement is not necessary, just, or reasonable, and is a policy choice that the Commission should reject. Committing billions in ratepayer funds to new projects should not be justified based on such extreme assumptions, which are inconsistent with the significant expenditures for preferred resource programs, the loading order, and the state's greenhouse gas (GHG) requirements.

- Even under this extreme scenario, however, the evidence shows that if the most recent available CEC load forecast and energy efficiency data are considered, no LCR need exists in the SONGS study area. The evidence also shows that even without consideration of the most up-to-date information, a combination of proposed transmission mitigation, reactive support, and procurement of already-authorized preferred resources and energy storage reduces the LCR need in the SONGS study area to zero.

RECOMMENDATION 2: If the Commission finds there is an LCR need, which CEJA believes there is not, CEJA urges the Commission to limit any procurement authorization to preferred resources.

RECOMMENDATION 3: The contingency plans requested by SDG&E and SCE are not needed at this time. There are better means of providing for delays in construction of transmission projects, the implementation of preferred resources, or other eventualities that do not impose the same burdens on ratepayers. The use of SDG&E's WECC-certified SPS is one such measure. CEJA also recommends that the Commission seek short-term (2-4 year) extensions of Encina and other OTC plants in order to allow resources such as the energy storage required by the recent storage decision to come online.

ACRONYM LIST

AB	Assembly Bill
ALJ	Administrative Law Judge
AMI	Advanced Metering Infrastructure
BBEES	Big Bold Energy Efficiency Strategy
CAISO	California Independent System Operator
CARB	California Air Resources Board
CCC	California Cogeneration Council
CEC	California Energy Commission
CEJA	California Environmental Justice Alliance
CHP	Combined Heat & Power
CSI	California Solar Initiative
DR	Demand Response
DG	Distributed Generation
DRA	Division of Ratepayer Advocates
EAP	Energy Action Plan
EE	Energy Efficiency
FERC	Federal Energy Regulatory Commission
FIT	Feed in Tariff
GHG	Greenhouse Gas
IEPR	Integrated Energy Policy Report
IOU	Investor-Owned Utility
LCR	Local Capacity Requirements
LSE	Load Serving Entity

SB_GT&S_0140708

LTPP	Long-Term Procurement Plan
MT	Metric ton
MW	Megawatt
NEM	Net Energy Metering
NERC	North American Reliability Corporation
NQC	Net Qualifying Capacity
OTC	Once-Through Cooling
PG&E	Pacific Gas & Electric
PLS	Permanent Load Shifting
PV	Photovoltaic
PURPA	Public Utility Regulatory Policies Act
QF	Qualifying Facility
RAM	Renewable Auction Mechanism
RFO	Request for Offers
RPS	Renewable Portfolio Standard
RA	Resource Adequacy
SGIP	Self-Generation Incentive Program
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SPS	Special Protection Scheme/System
WECC	Western Electricity Coordination Council

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CALIFORNIA ENVIRONMENTAL JUSTICE ALLIANCE'S TRACK 4 OPENING BRIEF

The California Environmental Justice Alliance (CEJA) respectfully submits this Opening Brief. This Opening Brief is timely submitted pursuant to the schedule decided by the Administrative Law Judge at the evidentiary hearing.

INTRODUCTION

The retirement of the San Onofre Nuclear Generating Station (SONGS) presents California with a crucial opportunity to ensure that the State meets its energy needs while complying with its environmental laws and advancing its environmental goals and policies. California is one of the largest greenhouse gas (GHG) emitters in the world and a leader in climate policy, making its GHG mitigation efforts important both nationally and globally. California has committed to mitigating the impacts of climate change by reducing greenhouse gas emissions to 1990 levels by 2020, and to reducing GHG emissions by 80 percent below 1990 levels by 2050. Making the right decisions related to SONGS will be critical to achieving those commitments, as well as to protecting communities that already live with the health consequences of power generation based on the burning of petroleum products.

The evidence in this case is that no new generation is needed in SONGS study area that has not already been authorized in Track 1. The need assessments in this proceeding are based on the extremely severe and unlikely assumption that on the hottest day in ten years three major transmission lines are out of service, no load-shed is allowed despite the existence of a WECC-approved Special Protection System ("SPS"), and an additional 2.5% reserve margin is added. Even using such an extreme reserve margin, the evidence shows that a combination of transmission solutions, reactive support, and existing resources are sufficient to meet local resource needs as measured by the most up-to-date CEC demand forecasts. Notably SCE, which is seeking procurement authorization here, found that, with the addition of one transmission project and the targeted use of resources already authorized, it has sufficient resources to meet NERC reliability standards without additional resource procurement. And SCE's conclusion was reached based on an outdated demand forecast and undercounted existing preferred resources substantially.

The Commission has an obligation to ensure that customers receive reasonable services at just and reasonable rates and to implement procurement-related policies that protect the environment. For the reasons set forth below, CEJA respectfully submits that neither SCE nor SDG&E has provided the Commission with any justification for burdening an already strained ratepayer based with the huge expense of new procurement.

I. REGULATORY AND POLICY BACKGROUND

A. The Commission's Statutory and Policy Obligations

In considering long-term procurement, the Commission must address a variety of concerns.[1] While one responsibility of the Commission is to ensure reliability in the electrical system, that responsibility must be balanced with other statutory and policy considerations.[2] The Commission has a statutory duty to ensure that customers receive reasonable services at just and reasonable rates.[3] The Commission also has a statutory mandate to implement procurement-related policies to protect the environment. The Commission has a further responsibility to ensure that utility procurement complies with the loading order, which "applies to all utility procurement, even if pre-set targets for certain preferred resources have been achieved."[4] And the Commission must consider environmental justice issues in connection with procurement determinations.[5]

B. Reliability Standards and Reserve Margins

The criteria used by the Commission for authorizing long-term procurement have been developing in recent years. Historically, for long-term procurement, the Commission generally relied on a 1-in-2 baseline forecast with a 15-17% reserve margin above the forecast load.[6] This reserve margin provided "the cushion should hotter than average weather occur."[7] Notably, this

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[1] For a more detailed discussion of the statutory and policy schemes affecting long-term procurement, see CEJA's Track 1 Opening Brief (Exhibit CEJA-1) filed September 24, 2012 at pp. 3-7.
[2] D.13-02-015 at p. 35.
[3] *PG&E v. Public Utilities Com'n* (2004) 118 Cal.App.4th 1174, 1198; *see also* Cal. Pub. Util. Code § 454.5.
[4] *Id*. at p. 20.
[5] D.07-12-052 at p. 157; *cf.* Cal. Pub. Util. Code §§ 399.13, 8281.
[6] *See* D.04-12-048 at p. 30, 53.
[7] *Id.* at p. 30; D.07-12-052 at pp. 28-29 (adopting this for the 2006 LTPP).

reserve margin is conservative when compared to, for example, the Western Electricity Coordinating Council's (WECC's) operating reserve margin of approximately 7% of peak demand.[8] D.04-01-050 required all LSEs within CA to procure sufficient capacity to meet an RA obligation equal to their 1 in 2 monthly peak load forecast plus a 15%-17% Planning Reserve Margin (PRM).

In 2006 the Commission determined that it was necessary to add a local procurement obligation to the overall RAR program to ensure local reliability as well as system reliability.[9] At that time the Commission stated:

> The LCR study is the foundation for our establishment of local procurement obligations, the costs of which are borne by the LSE's and their retail customers. Therefore, this Commission must be reasonably assured that the LCRs it uses to establish those procurement obligations are reasonable. This requires consideration of the LCR study process as well as the study outcomes.[10]

The Commission directed CAISO and other interested parties to meet and confer to work towards agreement on study scenarios to be used as input assumptions in the 2007 LCR study. CAISO's LCR study acknowledged the Commission's prerogative to determine the level of reliability required and presented three different service reliability options driven by NERC planning standards.[11] The second option, which the Commission chose, "represents LCRs and deficiencies associated with 'Performance Criteria-Category C' with operational solutions.[12] The

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[8] D.03-12-062 at p. 8; *see also* CEJA Ex. 1 at p. 32.
[9] D.06-06-064.
[10] *Id*. at p. 13 (emphasis added).
[11] *Id*. at pp. 16-17.
[12] *Id*.

Commission noted that "[b]y reflecting transmission operational solutions, this option allows for a lower generation requirement." The Commission also noted:

> Selecting one of these three reliability options invokes the Commission policy of balancing reliability objections against the cost of achieving a particular reliability level. We would prefer to have better quantitative information at our disposal regarding the probabilities of operational events as well as information regarding the ratepayer and societal costs of service interruptions. Moreover, we expect that progress can and should be made towards producing such information for future LCR studies.[13]

While the Commission found CAISO's 2007 LCR study to be reasonable for purposes of establishing Local RAR for that year, it expected modifications and refinements to the LCR study process in future years.[14] "Among other things, we find that future LCR studies would benefit from the use of a probabilistic rather than a deterministic approach."[15]

In this proceeding, CAISO, for the first time, based its long-term LCR study on a 1-in-10 annual peak load and a Category C Contingency. In the Decision Adopting Long-Term Procurement Plans Track 2 Assumptions and Scenarios dated December 24, 2012, the Commission approved the use of a 1-in-10 peak weather forecast for transmission planning and local area planning.[16] In Track 1 of this proceeding the Commission determined that CAISO's use of a scenario in which two import pathways to SCE's territory would be unavailable on the hottest day in 10 years was an acceptable methodology for consideration of LCR needs.[17] Similarly, in D-13-03-029 the Commission based its LCR determination, in part, on a CAISO study that included a power flow model of an outage of the Imperial Valley-Suncrest portion of

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[13] *Id.* at p 19 (emphasis added).
[14] *Id.*
[15] *Id.* at p. 3. The Commission also approved CAISO's use of a 1-in-10 summer peak load forecast as the basis for its study.
[16] D.12-12-010, Attachment A at p. 23.
[17] D.13-02-015 at p. 40.

the Sunrise transmission line followed by the non-simultaneous loss of the ECO-Miguel portion of the Southwest Powerlink transmission line.

However, in D.13-03-029 the Commission also noted that CAISO's choice of assumptions to be used in determining LCR need was not binding on the Commission: "[w]hile we respect the CAISO's statutory responsibility and its discretion to model its OTC study modeling based on assumptions that flow from it, the record of the proceeding highlights the limitations of our reliance on the OTC study for purposes of this Commission's statutory responsibility to ensure just and reasonable rates by, among other things, limiting unnecessary ratepayer costs."[18] Similarly, in Track 1 of this proceeding the Commission noted that a "significant difference between the ISO's reliability mission and the Commission's reliability emphasis is that the Commission must balance its reliability mandate with other statutory and policy considerations. Primarily, these considerations are reasonableness of rates and a commitment to a clean environment."[19]

It is noteworthy that the reliability options presented by CAISO to the Commission in 2006 were based on the North American Electric Reliability Corporation (NERC) reliability standards.[20] The reliability option presented by CAISO to the Commission in this proceeding is not, but rather reflects additional requirements imposed by CAISO.[21] Those additional requirements represent significant extra cost to ratepayers based on CAISO's unwillingness to

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[18] D.13-03-029 at p. 9.

[19] D.13-02-015 at p. 35.

[20] D.06-06-064 at pp. 16-17 ("These options reflect different service reliability levels that are driven by transmission grid operating standards that the CAISO must meet.").

[21] In fact, at least one very experienced expert has opined in this case that the contingency presented by CAISO is functionally a Category D event that should not have been modeled at all. *See* Ex. SC-1, Powers Opening Testimony, p. 3; RT pp. 1931:16-22, 1932:1-6, 1935:19-1940:6 (Powers, Sierra Club).

interrupt service to customers under highly unlikely circumstances. It is also noteworthy that in the years since 2006 neither the quantitative information regarding the probabilities of operational events nor the information regarding the ratepayer and societal costs of service interruptions that the Commission had hoped to see in future LCR studies has materialized.

CEJA raises this history only to emphasize that the Commission must be reasonably assured that the LCR it uses to examine procurement questions is reasonable, which "requires consideration of the LCR study process as well as the study outcomes."[22]

II. THE STUDIES

The California Independent System Operator ("CAISO"), Southern California Edison Company ("SCE") and San Diego Gas & Electric Company ("SDG&E") all submitted studies of long-term LCR need in the SONGS study area, which consists of the SDG&E service area and the Los Angeles Basin portion of the SCE service territory. CAISO conducted a study based on the Scoping Memo and evaluated the SONGS study area as a whole. SCE and SDG&E coordinated their studies, but began before the Commission set assumptions to be used for Track 4. SCE and SDG&E made separate assessments and procurement recommendations for their respective portions of the SONGS study area. Neither SCE nor SDG&E considered a solution that optimizes procurement in the entire SONGS study area. In fact, none of the studies provides a full picture from which the Commission can gain a complete understanding of resource options in the SONGS study area.

While each of these studies used different assumptions, all assumed the outage of the Sunrise Powerlink, system readjusted, followed by the outage of the Southwest Powerlink at the

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[22] D.06-06-064 at p. 10.

peak load hour on the hottest day in 10 years;[23] the outage of both these lines also severs the CFE from Otay Mesa to Tijuana.[24] Each of the studies also modeled a 1-in-10 peak load based on the mid-range economic and demographic assumptions contained in the August 2012 revision to the California Energy Commission ("CEC") 2012 Integrated Energy Policy Report.

None of the studies account for resources targeted in the Energy Storage Proceeding or for the increased energy efficiency forecasts and reduced load forecasts contained in the most recent CEC forecasting process.

The primary differences among the studies involve the method of study used, the use of the San Diego SPS to mitigate the studied contingencies, reactive power and transmission assumptions; and the way in which preferred resource deployment levels are assumed in or omitted from the different models. Not surprisingly, the study results varied.

A. CAISO

CAISO assumes that this series of transmission losses occurs with no activation of the SPS certified by WECC. This SPS is designed to trigger a controlled load shed in the San Diego Local Area as a mitigation of the contingency assumed in the study. CAISO's choice not to assume such a mitigation is not based on NERC or WECC reliability standards, but on CAISO's own determination that it is inappropriate.[25] This choice resulted in an increased need of 438 MW in the LA Basin, at least 150 MW in the San Diego local area, and has the potential for

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[23] Exhibit ISO 1 (Sparks Opening Testimony), at 6:11-13.
[24] Exhibit CEJA 2 (May Supporting Documents) at p. 49.
[25] Exhibit ISO-2 (Sparks Rebuttal Testimony) at p. 5:4-12.

reducing the effectiveness of certain proposed transmission options.[26] The policy cited by CAISO as the basis for its position has never been approved by the CAISO board.[27]

CAISO also adds a 2.5% reserve margin to its need calculation, which it says is required by WECC reliability standards although such a reserve is not required by NERC. CAISO did not model any transmission projects or reactive support mitigation that has not been board-approved by CAISO.

CAISO included all of the model inputs contained in Attachment A to the Revised Scoping Ruling and Memo of the Assigned Commissioner and Administrative Law Judge dated May 21, 2013 ("the Scoping Memo") as input assumptions and then reduced its residual need by 189 MW of demand response characterized as "First Contingency" resources. CAISO also reduced residual need by the full 1,800 MW of resources authorized in Track 1 for the LA Basin and 308 MW authorized in the San Diego PPTA Decision, which the Scoping Memo characterized as Second Contingency resources.[28] CAISO did not reduce residual need to account for incremental small PV and demand response that also were identified as Second Contingency resources by the Scoping Memo.

CAISO concludes that there is a residual resource need for the SONGS Study Area of 2534 MW if 80% of the resources are located in the LA Basin, and 2399 MW if two-thirds of the resources are located in the LA Basin. CAISO did not make its own recommendation regarding procurement, and advised deferring a decision on procurement until completion of its draft

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[26] RT pp. 2026:22 – 2028:5 (Chinn, SCE); RT pp. 1733:17 – 1734:13 (Jontry, SDG&E)
[27] RT at p. 1632:8-18 (Millar, CAISO)
[28] Scoping Memo, Attachment A at p. 13.

Transmission Plan in January, 2014.[29] CEJA agrees that no procurement should be authorized and that CAISO's transmission plan will contain crucial information pertinent to the Commission's decision in this proceeding. However, if the Commission chooses to move forward without that information,

CEJA submits that the Commission should adopt the two-thirds/one-third split and reduce CAISO's estimate of residual need by the following amounts:

- 1320-3200 MW to account for updated load forecast and energy efficiency projections;[30]
- 728 MW of additional energy efficiency local area impacts;[31]
- 1200 MW for the Mesa Loop-In;[32]
- 300 MW reflecting the addition of 550 MVAR of reactive support at SONGS;[33]
- 997 MW of Second Contingency Demand Response;[34]
- 278-496 MW of incremental small PV;[35]
- 49-126 MW of additional EE and DR resulting from use of an appropriate line loss rate;[36]
- 612 MW in storage procurement required by the Storage Decision;[37] and

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[29] Exhibit ISO-1 (Sparks Opening Testimony) at p. 31:1-7.
[30] See infra, pp. 17-22. As discussed below, CAISO can find an additional 885 MW of additional energy efficiency local area impacts in 2022. However, since 157 MW of that amount is due to the updated load forecast and EE projections mentioned in the previous bullet point, that amount was subtracted here to avoid double-counting.
[31] See infra, pp. 22-27.
[32] See infra, pp. 30.
[33] See infra, pp. 32-34.
[34] See infra, pp. 39-43.
[35] *Id.*
[36] See infra, pp. 26-27.
[37] See infra, pp. 34-39.

- For 2022, the MW reduction resulting from two 140 MVAR synchronous condensers currently in place at Huntington Beach or 939 MW of generation resulting from the proposed re-powering of Huntington Beach with a combined cycle plant.[38]

CEJA submits that the NERC reliability standards provide a sufficient level of reliability for LTPP purposes, that the 2.5% margin applied by CAISO (704 MW in added need) should not be used, and that the San Diego SPS (438-600 MW need reduction) should at least be assumed as an interim measure while other resources are put into place.

B. SCE

SCE's study differs from CAISO's in the following respects:

1. SCE uses NERC reliability standards, and so includes load shedding as an option;
2. SCE models potential transmission solutions not addressed by CAISO;
3. SCE does not add the 2.5% margin applied by CAISO; and
4. SCE does not assume the retirement of certain non-OTC generation (which SCE says had very little effect on the amount of local generation needed).

SCE's studies found, after subtracting the 1800 MW of resources authorized in Track 1, a residual need in the LA Basin of about 1000 MW. SCE concludes that a targeted use of existing or already-authorized preferred resources together with the development of the Mesa Loop-In transmission project reduces its residual need to zero using NERC reliability standards.[39] SCE's

[38] Exhibit CEJA-1 (May Opening Testimony) at pp. 8-9.
[39] Exhibit SCE-1 (SCE Opening Testimony) at p. 6:21 – 7:4.

SB_GT&S_0140720

request for authorization to procure 500 MW is based on CAISO's insistence that the San Diego SPS not be implemented.

CEJA agrees with SCE that the NERC reliability standards provide a sufficient margin and that the 2.5% margin applied by CAISO (704 MW in added need) is unduly conservative. CEJA also agrees that the San Diego SPS should be assumed as an available mitigation to the modeled contingencies (438-600 MW need reduction).

CEJA further recommends that the Commission deny SCE's procurement request, as SCE failed to consider the following reductions to need:

- 1200-2650 MW to account for updated load forecast and energy efficiency projections;[40]
- 453 MW of additional achievable energy efficiency local area impacts;[41]
- 606 MW to account for the difference between the DR and incremental small PV specified in the Scoping Memo and that used by SCE in its Preferred Resources Scenario;[42]
- 300 MW reflecting the addition of 550 MVAR of additional reactive support at SONGS;[43] and
- 447 MW to reflect storage procurement required by the Energy Storage Decision.[44]

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[40] See infra, pp. 17-22.
[41] See infra, pp. 22-27. As discussed below, SCE can find an additional 543 MW of additional energy efficiency local area impacts in 2022. However, since 90 MW of that amount is due to the updated load forecast and EE projections mentioned in the previous bullet point, that amount was subtracted here to avoid double-counting.
[42] See infra, pp. 39-43.
[43] See infra, pp. 32-34.

C. SDG&E

SDG&E's studies differ from CAISO's and the Scoping Memo as follows:

1. SDG&E includes no preferred resources in its study other than what is embedded in the CEC load forecast, except for No. 2 (below);
2. SDG&E assumes that only 20 MW of wholesale DG PV "net qualifying capacity additions will be in service by 2022;
3. The principal difference in 2022 LCR need between SDG&E's study assumptions and the Scoping Memo assumptions is the SDG&E assumptions regarding gas-fired generation retirements and gas-fired generation additions.
4. SDG&E does not assume implementation of its SPS to shed load.
5. SDG&E used the CEC's mid-case estimate of EE for its local capacity area.
6. SDG&E models potential transmission solutions not addressed by CAISO;

SDG&E found about 620 MW of resource need after application of transmission solutions and then asked for a slightly lower amount of procurement (about 500-550 MW), based on the idea that it had not accounted for any DR and preferred resources in its studies. CEJA recommends that SDG&E's procurement request be denied, based on the following reductions:

- 108-553 MW to account for updated load forecast and energy efficiency projections;[45]
- 123 MW of additional EE local area impacts;[46]

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[44] See infra, pp. 34-39.

[45] See infra, pp. 17-22.

[46] See infra, pp. 22-27. As discussed below, SDG&E can find an additional 211 MW of additional energy efficiency local area impacts in 2022. However, since 88 MW of that amount is due to the updated load forecast and EE projections mentioned in the previous bullet point, that amount was subtracted here to avoid double-counting.

- 97 MW of incremental small PV specified in the Scoping Memo but not accounted for by SDG&E;[47]
- 219 MW of DR specified in the Scoping Memo but not accounted for by SDG&E;[48] and
- 165 MW of energy storage required by the Energy Storage Decision.[49]

III. DISCUSSION

A. The Contingency on Which CAISO, SCE and SDG&E Base Their Determination of LCR Need is Extremely Conservative

According to CAISO "the most critical N-1-1 contingency for the SONGS Study Area is the outage of the Sunrise Powerlink, system readjusted, followed by the outage of the Southwest Powerlink."[51] However, the outage of both these lines also causes the severance of a CFE line from Otay Mesa to Tijuana as well.[52] CAISO characterizes this critical contingency as a Category C3 contingency[53] which is defined as the loss of a single element, manual system readjustment, followed by the loss of another element.[54] Under NERC Reliability Standards, CAISO is required to demonstrate that it can operate its transmission system under contingency conditions defined in Category C.[55]

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[47] See infra, pp. 39-43.
[48] See infra, pp. 39-43.
[49] See infra, pp. 34-39.
[51] Exhibit ISO-1 (Sparks Opening Testimony), at 6:11-13.
[52] Exhibit CEJA 2 (May Supporting Documents) at p. 49.
[53] Exhibit ISO-1 (Sparks Opening Testimony), at 6:8-13.
[54] Exhibit CEJA 2 (May Supporting Documents) pp. 151-155.
[55] Exhibit CEJA 2 (May Supporting Documents) pp. 151-155.

SB_GT&S_0140723

Sierra Club's expert witness Bill Powers testified that the contingency modeled by CAISO is functionally a Category D contingency under WECC reliability standards, using a probabilistic analysis.[56] A Category D contingency is an extreme event resulting in two or more (multiple) elements removed or cascading out of service.[57] Unlike a Category C contingency, CAISO is not required to demonstrate operability during a Category D contingency.[58] Rather, it must only evaluate the risks and consequences of these extreme contingencies.[59] If Mr. Powers is correct, this contingency is entirely inappropriate for use to determine LCR needs. But regardless of who is correct, the fact that there is a debate at all indicates that the use of this scenario to determine LCR need in Track 4 is extremely conservative.[60]

This contingency also is extremely unlikely to occur. While none of the studies include any probabilistic analysis, there have been various assessments of this probability in testimony. By definition, the 1-in-10 peak load is itself an infrequent event. According to ORA witness Robert Fagan, the highest load on the combined Orange County SCE/SDG&E region occurs for no more than 89 hours over the course of the 3,672-hour period between May 1 and September 30th, or less than 2.5% of the total hours in the period.[61] In Track 1 CAISO admitted that an N-1-1 contingency had never occurred in the Western LA Basin during the past ten years,[62] making the probability of the contingency events occurring on the order of less than a minute in a ten-

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[56] Exhibit SC-1 (Powers Opening Testimony) at p. 3; RT pp. 1931:16-22, 1932:1-6, 1935:19-1940:6 (Powers, Sierra Club).

[57] Exhibit CEJA 2 (May Supporting Documents) pp. 151-155.

[58] *Id.*

[59] *Id.*

[60] On top of the need resulting from the use of this contingency CAISO adds a 2.5% margin, which alone increases its residual need calculation by 704 MW. *See* Exhibit CEJA-1 (May Opening Testimony) at p. 33.

[61] Exhibit ORA-3 (Fagan Reply Testimony) at p. 9.

[62] RT 120:2-28 (Sparks, CAISO).

year period.[63] (Similarly, in a parallel issue in A.11-05-023, CEJA's expert calculated the probability of CAISO's and SDG&E's forecasted contingencies to be less than a minute in a ten-year period.)[64] Redondo Beach's expert Jaleh Firooz testified in her Track 4 testimony that the likelihood of an N-1-1 event taking place on the hottest day in ten years at the hour of peak demand is about 1 chance in a billion.[65]

CAISO also included an additional 2.5% reserve margin in its study, thereby increasing its assessment of LCR needs in the SONGS study area substantially. CAISO calculated that the addition of a this reserve margin increased LCR needs by 670 MW in 2018 and 704 MW in 2022 above the 1-in-10 worst year peak demand forecast.[66] SCE, in contrast, did not add the 2.5% reserve margin to its study assumptions because it is not required by NERC reliability standards.[67]

Despite the use of this extreme and improbable scenario, a complete analysis of demand and available resources shows that there is no mid-term or long-term residual LCR need in the SONGS study area beyond the resources already authorized in prior proceedings. As is demonstrated below, when the most recent demand forecasts and energy efficiency information is considered along with already-proposed transmission solutions, no need exists. Moreover, proper consideration of energy storage procurement already ordered by the Commission and additional preferred resources set forth in the Scoping Memo, which are all but ignored in all three LCR studies, also easily meet anticipated needs.

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[63] Exhibit CEJA-1 (May Opening Testimony) at pp. 38-39.
[64] *Id.*
[65] Exhibit RB-1a, (Firooz Opening Testimony and Attachments) at p. 6, fn. 8.
[66] Exhibit CEJA-1 (May Opening Testimony) at p. 33; Exhibit CEJA-2 (May Supporting documents) at pp. 60-61.
[67] Exhibit SCE-1 (SCE Opening Testimony) at p. 26:5-13.

SB_GT&S_0140725

CEJA's primary purpose in identifying the extreme nature of the contingency selected by CAISO is to point out that this is not a close call. The margin of error provided by the use of this extreme, unlikely scenario is easily great enough to ease any concerns regarding the supposed uncertainty that new resources already in development will materialize in the next decade.

B. The Commission should update its assumptions by using data from the September 2013 updates to the CEC's California Energy Demand 2014-2024 Preliminary Forecast

When the Commission set its input assumptions in the Scoping Memo, it based them on forecasts in the 2012 Integrated Energy Policy Report ("IEPR"), August 2012 revision, forms 1.5c & d.[68] The 2012 IEPR is based on the 2012 CPUC Energy Efficiency Potential Study (May 2012) and the CEC's California Energy Demand 2012-2022 Final Forecast.[69] CAISO, SCE, and SDG&E all based their study assumptions on that same data set. [70] When the Commission ultimately makes a decision in this Track 4 proceeding in early 2014, that data set will be over a year and a half old. More importantly, that data provides an incomplete basis upon which to estimate energy savings through 2022 because it lacks information such as the CEC's building efficiency standards set to take effect in 2017 and 2020 and other energy efficiency codes and standards that will produce savings from 2015 and beyond.[71]

In May 2013, in support of the 2012 IEPR and the forthcoming 2013 IEPR, the CEC published the California Energy Demand 2014-2024 Preliminary Forecast and updated it this

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[68] Scoping Memo, Attachment A at p. 3.

[69] Exhibit NRDC-1 (Martinez Opening Testimony) at p. 7, Diagram 1.

[70] Exhibit ISO-1 (Sparks Opening Testimony) at p. 4:16-21; Exhibit SCE-1 (SCE Opening Testimony) at p. 31:9-22; Exhibit SDG&E-1 (Anderson Opening Testimony) at p. 6:7-10.

[71] Exhibit NRDC-1 (Martinez Opening Testimony), at 6-7.

past September.[72] The revisions in the September 2013 update significantly reduced the demand forecast in the SONGS study area as compared to the 2012 numbers due to changes in the price elasticity of demand and the adoption of two new efficiency regulations: Title 20 Battery Charger Standards and Title 24 Building Standards, neither of which was included in the previous forecast.[73]

The CEC's September 2013 update contains a baseline forecast (using the same mid-case for 1-in-10 year peak as in the Scoping Memo) that reduces the total demand for the LA Basin and San Diego regions by 1208 MW for 2018, and 1321 MW for 2022 as compared to the 2012 numbers used by CAISO, SCE, and SDG&E. The CEC also provided a forecast which included Additional Achievable Energy Efficiency (AAEE, previously referred to as uncommitted EE) which showed total need reductions of 2234 MW in 2018 and 3203 MW in 2022 (again, the mid-range forecast, 1-in-10 peak). The difference between the numbers used in the Scoping Memo and the September 2013 update can be seen in the table below:[74]

Revised Scoping/Aug. 2012 CEC forecast			Updated CEC Sept 2013 baseline		Difference (MW)	
	2018	**2022**	**2018**	**2022**	**2018**	**2022**
L.A. Basin	21,870	22,917	20,609	21,704	1,261	1,213
San Diego	5,652	6,056	5,705	5,948	-53	108
Total	27,522	28,973	26,314	27,652	**1,208**	**1,321**
			Updated CEC Sept 2013 AAEE forecast		**Difference (MW)**	
			2018	**2022**	**2018**	**2022**
			19,819	20,267	2,051	2,650
			5,469	5,503	183	553
			27,306	27,792	**2,234**	**3,203**

72 Exhibit CEJA-1 (May Opening Testimony) at p. 42.
73 *Id.* at p. 43.
74 *Id.* at p. 43, Table 2.

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Clearly there is a significant difference between the assumptions put forth in the Revised Scoping Ruling and the most recent demand forecast. Even though the peak load assumptions used in the Scoping Memo represented the most recent available information at the time, that is no longer the case in light of the September 2013 update. It would be prudent for the Commission to take this reduction into account in considering local resource needs.

The Commission has previously endorsed using the most recent CEC demand forecast, even in draft form. For example, the CPUC decided to use the 1-in-2 summer forecast in the 2007 draft CEC base case – then the most recent forecast available – even though that base case had not previously been part of the proceeding.[75] The Commission explained its policy of making decisions based on the most currently available public information:

> *We find it prudent to update the forecast estimates as inputs in this decision based on the most current public information available to us*, particularly given the long time lag that has occurred since the LTPPs were developed. The California Energy Demand Forecast, 2008-2018, the underlying load forecast which the 2007 IEPR assumes, had not been officially adopted by the CEC, as of the mailing of this Proposed Decision. We note the incorporation of the draft 2007 IEPR demand forecast into our overall needs analysis may give certain parties concern, however, we believe that the draft forecast provides a better 'snapshot' of the current needs of the system.[76]

The Commission also noted that using the new draft CEC forecast in the LTPP was reasonable since "CEC's IEPR process is the proper forum to litigate and contest issues related to each IOU's demand forecast."[77] As in the aforementioned case, Track 4 has seen a time lag between the issuance of the Scoping Memo and the decision during which an updated demand forecast was published. Additionally, even though that September 2013 forecast has yet to be

[75] D.07-12-052 at 29.
[76] *Id*. at 29-30.
[77] *Id*. at 29.

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adopted by the CEC, the Commission should still adopt that update just as it did with the unofficial forecast in the above-mentioned case. Indeed, in this very proceeding the Commission has already used efficiency assumptions that the CEC had yet to adopt in both the Track 1 decision and the Track 4 Scoping Memo.[78] The Commission should do the same here.

CAISO has stated it wants to consider incorporating the 2013 IEPR demand forecast.[79] SCE, SDG&E, and IEPA, however, argue that the Commission should not use the CEC's September 2013 update to the demand forecast.[80] All three offer the same rationale for ignoring the update, arguing in essence that it is more important to 'fix' assumptions in order to produce results than it is to get those results right.[81] However, preferring older assumptions to newer and more complete data that is readily available would subvert the Commission's stated preference for a better 'snapshot' of the current needs of the system.[82] Moreover, the September 2013 update is not so new that the Commission, CAISO, the IOUs, and all other parties in this proceeding have been unable to take it into consideration – in fact those parties have participated extensively in the process that resulted in the update. Additionally, both CEJA and NRDC discussed the update extensively in their testimonies[83] and it was a subject of cross-examination during the hearing.[84] For these reasons, the arguments of SCE, SDG&E, and IEPA should be rejected.

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[78] RT 2181:1-10 (Martinez, NRDC).
[79] Exhibit ISO-1 (Sparks Opening Testimony) at p. 30:11-13.
[80] Exhibit ISO-2 (Sparks Rebuttal Testimony) at p. 6:20 – 7:11; SDG&E Track 4 Comments on ALJ Questions from Pre-Hearing Conference held September 4, 2013 at 3; RT 2255:5-28 (Monsen, IEPA).
[81] Exhibit SCE-2 (Various Witnesses Rebuttal Testimony) at p. 7:5-6.
[82] D.07-12-052 at pp. 29-30.
[83] Exhibit CEJA-1 (May Opening Testimony) at pp. 42-45; Exhibit NRDC-1 (Martinez Opening Testimony) at pp. 4-14.
[84] RT 2178-2199 (Martinez, NRDC).

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Both CAISO and SCE also have expressed concern about uncertainty in the updated demand forecast, citing the fact that the revised forecast is not yet final.[85] This position ignores the fact that Commission precedent supports the use of such a draft demand forecast if it constitutes the most current publically available information.[86] Additionally, the Commission has explained that:

> Informed decision-making depends on robust analysis. While we recognize that electric resource planning is inherently uncertain, perhaps now more than ever before, we expect the IOUs to integrate the best, most recent planning methodologies and analytical techniques. In subsequent iterations of the long-term procurement process, the IOUs will be expected in their resources planning to meet and exceed the high standards Californians expect as pacemakers on energy and environmental issues.[87]

Employing uncertainty as an excuse for rejecting the best, most recent information regarding energy and environmental issues ignores the fact that uncertainty is inherent in any process intended to predict the future. But CAISO and SCE actually have it backwards: demand forecasting is a tool used to *mitigate* uncertainty, not one that inherently amplifies it; and using the most currently available information only enhances the odds of accuracy.

Of course, even the most robust analysis does not necessarily lead to 100% accuracy when it comes to forecasting, and the concern expressed by CAISO and the IOUs might resonate given their charge of managing reliability but for one fact: every IEPR forecast for the last 22 years has *overestimated actual consumption*. That is, since the 1990 IEPR forecast, actual consumption was less than the end point forecast every single time.[88] As adoption of the

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[85] Exhibit SCE-2 (Various Witnesses Rebuttal Testimony) at p. 7:2-4; RT 1495:17-27 (Sparks, CAISO).
[86] D.07-12-052 at pp. 29-30.
[87] D.07-12-052 at p. 6.
[88] RT 2185:7-14 (Martinez, NRDC) (emphasis added).

September 2013 update would mitigate uncertainty and the risk of it overestimating demand is small, uncertainty is not a valid reason to refuse to utilize the CEC's most recent update to the demand forecast.

C. The Commission should reduce the local capacity needs estimated by CAISO, SCE, and SDG&E for the LA Basin and San Diego local areas to account for savings that are reasonably expected to occur but were omitted from their energy efficiency assumptions.

The Revised Scoping Ruling and Memo provided inaccurately low input assumptions for energy efficiency by (1) relying on an incomplete assessment of energy efficiency potential, (2) omitting incremental naturally occurring savings, and (3) incorrectly using a low estimate of SDG&E's local area rather than the mid-case estimate.[89] The additional EE savings discussed below should be used to reduce authorization for any local capacity needs by at least 885 MW, 543 MW, and 211 MW (by 2022) respectively.[90]

The Revised Scoping Memo provided 933 MW of EE by 2022 as an input assumption.[91] These energy savings were derived from the CEC's analysis of how much EE was incremental to its demand forecast. In turn, that CEC analysis was based on the CPUC's 2012 energy efficiency potential study.[92] The 2012 potential study estimated future EE savings from efficiency codes and standards adopted as of March 2012 and from future utility programs, but did not offer a complete assessment of all future expected energy savings.[93] Because the 2012 potential study focused primarily on 2013 and 2014, it excluded the CEC's new Title 24 building efficiency

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[89] Exhibit NRDC-1 (Martinez Opening Testimony) at p. 4-5.
[90] *Id*. at 4 and 13.
[91] Scoping Memo, Attachment A at p. 3, Summary Table.
[92] Exhibit NRDC-1 (Martinez Opening Testimony) at p. 5-6.
[93] *Id*. at 6.

standards,[94] many finalized future federal appliance standards, and other energy efficiency codes and standards that will produce savings from 2015 and beyond.[95] The 2012 potential study and the CEC analysis based on it were therefore incomplete and, correspondingly, the EE assumptions in the Scoping Memo also were incomplete.[96]

The CEC's September, 2013 updated California Energy Demand 2014-2024 Preliminary Forecast in September was based on the new 2013 Final Draft Potential Study (August 6, 2013)[97]. The updated studies include many of the energy savings that were omitted from the 2012 study, and as a result reflect an increase in estimated future energy efficiency.[98] Comparing the 2012 numbers used in the Scoping Memo to the updated numbers in the 2013 CEC analysis, then adjusting the LA Basin number to account for local impacts in the SONGS area reveals an additional 157 MW (90 MW in the LA Basin and 67 MW in San Diego) of expected energy efficiency savings.[99] Since both CAISO and SCE utilized the 2012 numbers reflected in the Revised Scoping Memo, their findings should be updated with the newer data, reducing their needs by 157 MW and 90 MW respectively.

The Scoping Memo also overlooked incremental savings from energy efficiency that the CEC classifies as 'naturally occurring.'"[100] The CEC developed a separate forecast of the

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[94] Cal. Code Regs, title 24, part 6.

[95] Exhibit NRDC-1 (Martinez Opening Testimony) at p. 6-7. Since the 2012 Potential Study was published on May 8, 2012, it did not account for federal standards finalized after that date. Such standards include 77 FR 31918 (10 CFR 430.32(f)(3)) for dishwashers passed May 30, 2012; 77 FR 32308 (10 CFR 430.32(g)(2)) for clothes washers passed May 31, 2012; and 78 FR 36316 (10 CFR 430.32(j)(3)) for microwave ovens passed August 16, 2013.

[96] Scoping Memo, Attachment A at p. 4.

[97] Exhibit NRDC-1 (Martinez Opening Testimony) at p. 7, fn. 10.

[98] *Id*. at p. 7.

[99] *Id*. at pp. 8-9 and Tables 1, 2, and 3.

[100] *See*: Exhibit NRDC-1 (Martinez Opening Testimony) at p. 10: These EE savings "are expected to occur by definition and are not included in the CEC's demand forecast nor in the amount of incremental savings attributed to

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incremental amount of "naturally occurring" savings and estimated the amount of "naturally occurring" EE savings to be 714 MW (593 MW in the LA Basin and 123 MW in San Diego) in the 2022, low-savings scenario.[101] As this estimate is based on the CEC's old September 2012 analysis of the CPUC's 2012 potential study (still the most recent assessment of incremental naturally occurring savings), it is rather conservative.[102] After adjusting the LA Basin number to account for impacts in the SONGS area, the overall impact of "naturally occurring" energy efficiency savings in the entire SONGS study area amounts to 576 MW (453 MW in the LA Basin and 123 MW in San Diego).[103] Therefore, as with the updated input assumptions, the need findings of CAISO, SCE, and SDG&E should be reduced by 576 MW, 453 MW, and 123 MW respectively.

The Scoping Memo directed CAISO to use the "low level of [EE] savings for use in this set of studies" in SDG&E's local capacity area.[104] Normally, the low estimate would be used to account for the uncertainty of locational impacts of energy efficiency within a utility's service area.[105] The Scoping Memo mistakenly applied that methodology to SDG&E even though SDG&E's service territory is the same as its local capacity area and consequently any energy

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programs, codes, and standards." The CEC found "naturally occurring" energy efficiency in the 2012 potential study that significantly exceeded the "naturally occurring" EE already included in the CEC's 2012 forecast.

[101] Exhibit NRDC-1 (Martinez Opening Testimony) at p. 10, fn. 18. The data discussed is referred to in the NRDC footnote. It can be found in this document: CEC, Estimates of Incremental Uncommitted Energy Savings Relative to the California Energy Demand Forecast
2012-2022, "Incremental Uncommitted Efficiency Savings for Electricity," Low Savings Case, Rows 77 and 115 (September 20, 2012). Available at: http://www.energy.ca.gov/2012_energypolicy/documents/demandforecast/IUEE-CED2011_results_summary.xls.

[102] *Id.* at p. 10.

[103] *Id.* at p. 11, Table 4.

[104] Scoping Memo, Attachment A at p. 4.

[105] *Id.* When the service territory of a large utility that has areas both inside and outside a local capacity area is unlikely to have savings spread completely evenly throughout the territory, the CPUC will make a low savings estimate of energy efficiency to account for the possibility that the local capacity area might not get a proportional share of territory-wide savings; a "mid" estimate would reflect the CEC's best estimate across the entire territory.

efficiency installed in SDG&E's service territory is also installed in its local capacity area.[106] Therefore, there should be no reduction "due to uncertainty of the locational impact" and the "amount included in the local area should simply be the amount reasonably expected to occur in SDG&E's service territory, since they are the same geographical area."[107] To determine that amount, the Scoping Memo clearly stated: "across the SCE and SDG&E areas we expect the mid-level of savings to occur."[108] The Commission should use the "mid" amount of EE impacts reasonably expected to occur in the San Diego local area, which according to the CEC's recent September 2013 update, is 406 MW.[109] The amount of EE included in the CEC's most recent analysis in the low case was 254 MW in 2022, yielding an additional 152 MW in SDG&E's service territory that should be subtracted from CAISO's estimates of San Diego's local need.[110]

SDG&E properly applied the mid case estimate of 318 MW (from the 2012 data) in its study.[111] However, as discussed above, the mid case estimate for EE savings in the September 2013 update is 406 MW and, therefore, SDG&E's estimate should be adjusted accordingly. The CPUC should take that 88 MW difference into account when making need determinations.

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[106] *Id.*

[107] *Id.* at p. 11-12.

[108] Scoping Memo, Attachment A at p. 4.

[109] Exhibit NRDC-1 (Martinez Opening Testimony) at p. 12, fn. 22. The data discussed is referred to in the NRDC footnote. It can be found in this document: CEC, Estimates Of Additional Achievable Energy Savings, Supplement to California Energy Demand 2014-2024 Revised Forecast, Tables 28: SDG&E Service Territory AAEE Savings – Low Savings Case (Scenario 1), p. 37 (September 2013).

[110] Exhibit NRDC-1 (Martinez Opening Testimony) at p. 12. In the alternative, if the CPUC does not use the CEC's updated analysis from the September 2013 and instead uses the old assumptions from the Scoping Memo, then CEJA endorses the NRDC's recommendation accounting for the difference between "mid" and "low" estimates of need in the CPUC Revised Scoping Memo. There, the "low" estimate was 187 MW in 2022 and the "mid" was 318 MW in 2022, which yields 131 MW of energy savings that should be reduced from the estimates of need in the San Diego local area in 2022. Scoping Memo, Attachment A at p. 4. For "mid" estimate, the CPUC Revised Scoping Memo then footnotes the CEC's analysis of incremental energy efficiency at: http://www.energy.ca.gov/2012_energypolicy/documents/demand-forecast/IUEECED2011_results_summary.xls.

[111] Exhibit SDG&E-1 (Anderson Opening Testimony) at p. 5. *See also*: Exhibit NRDC-1 (Martinez Opening Testimony) at p. 13, FN 25.

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To summarize: the Commission should employ the following additional energy efficiency local area impacts in 2022, above and beyond the Revised Scoping Memo:[112]

	Updated Potential Study and CEC Analysis	Including Incremental Naturally-Occurring Savings	Using SDG&E's Mid Case Estimate Instead of Low Case	Total
LA Basin	90 MW	453 MW	-	543 MW
San Diego	67 MW	123 MW	152 MW	342 MW
SONGS Study Area	157 MW	576 MW	152 MW	**885 MW**

SDG&E's energy efficiency input assumptions should include an additional 211 MW (i.e. 123 MW of naturally occurring savings + 88 MW for the updated mid-case assumption).

D. The Total Megawatt Value of DG, EE, and DR Gained Through Avoided Transmission Was Underestimated

CAISO's testimony recognized distributed resources avoid transmission loss because they do not require transmission over long distances.[113] However, CAISO used too low a percentage of distribution system loss – 4.76% – for energy efficiency and demand response in the LA Basin and San Diego service areas.[114]

Appropriate line loss rates actually range from 5.5% to 11% at peak hours depending on location. CPUC consultant E3 calculated more conservative loss factors which, when converted to loss rate percentages, resulted in loss rates of 7.7% for SCE and 7.5% for SDG&E.[115]

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[112] Exhibit NRDC-1 (Martinez Opening Testimony) at p. 5, Table 1.
[113] Exhibit CEJA-1 (May Opening Testimony) at p. 16; *see*: Exhibit ISO-1 (Sparks Opening Testimony) at pp. 5-6.
[114] Exhibit ISO-1 (Sparks Opening Testimony) at p. 5:10-11. Losses can be measured as either a "Loss Rate" – a percentage of produced power lost – or "Loss Factor" – a number greater than one, multiplied by the generation needed for the load to reflect the added power needed to make up for transmission losses. Loss rates and loss factors can be converted to each other. Exhibit CEJA-1 (May Opening Testimony) at pp. 16-17.
[115] Exhibit CEJA-1 (May Opening Testimony) at p. 17.

Applying those loss rates to the numbers in CAISO's opening testimony Tables 2, 3, and 4[116] results in an additional 49MW of reduced need beyond the reductions already found by CAISO:[117] Application of the 11% peak loss rate, which arguably is the rate most applicable to a 1-in-10 peak load forecast, results in an adjustment from CAISO's numbers of 126 MW.

Since CAISO did not provide any support for its low loss rate, the Commission should use the more appropriate rates discussed above to adjust CAISO's energy efficiency savings due to loss by an additional 49 MW to 126 MW.

E. The Commission Should Assume The Use Of SDG&E's WECC-Approved SPS for Controlled Load Shed

SDG&E has a WECC-certified load shedding SPS in place to mitigate the N-1-1 of the Southwest Powerlink and the Sunrise Powerlink.[118] NERC Reliability Standards permit controlled load shedding for Category C events.[119] SCE Witness Chinn testified that in SCE's Scenario No. 1, the all-generation scenario, that inclusion of the SPS reduced local area need in the LA Basin by 438 MW. Mr. Chinn further testified that including the SPS in SCE's Transmission Scenario reduced local area need in the LA Basin by 900 MW.[120] SCE's study concludes that a combination of its Transmission Scenario with the SPS implemented and its Preferred Resource Scenario (based on resources already authorized in Track 1) reduces the LCR need in the LA Basin local area to zero.[121] However, although CAISO acknowledges the

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[116] Exhibit ISO-1 (Sparks Opening Testimony) at pp. 5 (Table 2), 6 (Table 3), and 7 (Table 4).
[117] Exhibit CEJA-1 (May Opening Testimony) at p. 17-18.
[118] Exhibit SDG&E-3 (Jontry Opening Testimony), at p. 7; RT 1703:12-24 (Jontry-SDG&E)..
[119] Exhibit CEJA-1 (May Opening Testimony) at pp. 34-35.
[120] RT 2026:17-27 (Chinn-SCE).
[121] Exhibit SCE-1 (Various Witnesses Opening Testimony) at pp. 6:21 – 7:4.

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presence of the SPS as a potential mitigation for the contingency in its LCR study, it refuses to consider the use of that SPS in that scenario.[122] SCE's procurement request to the Commission is based almost entirely on this difference.

SDG&E does not directly include the effect of any load shedding SPS when considering the range of need, even though it acknowledges the presence of a Western Electricity Coordinating Council (WECC)-approved SPS for the key N-1-1 contingency event.[123] SDG&E assumes, as does CAISO, that new generation is needed to resolve the contingency. However, SDG&E witness Jontry testified that accounting for the SPS reduced need in the San Diego local area by 150 MW.[124]

All of the witnesses who testified on the subject agreed that use of the SPS to load shed under the contingency modeled by CAISO and the utilities was permissible under NERC and WECC standards. SDG&E witness John Jontry and CAISO witness Sparks agreed that use of an SPS as an interim measure while new preferred resources, transmission mitigations or generation were being developed could be appropriate.[126] CAISO in fact has used such a solution in other heavily populated areas pending completion of transmission projects.[127] Mr. Sparks confirmed that such an interim use could last as long as a decade while a transmission project was under development.[128]

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[122] Exhibit ORA-3 (Fagan Reply Testimony) Attachment B (CAISO Data Request Response 2).
[123] Exhibit ORA-3 (Fagan Reply Testimony) at p. 3.
[124] RT at p. 1710:10-1711:12 (Jontry, SDG&E)
[126] RT at p. 1710:10-1711:12 (Jontry, SDG&E); RT 1411:1 – 1413:13 (Sparks, CAISO)
[127] RT at p. 1470:1 – 1471:9 (Sparks, CAISO)
[128] RT at p. 1411:1 – 1413:13 (Sparks, CAISO)

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CAISO's choice to assume that this SPS is not utilized in response to the loss of three major transmission lines was not backed up by a probabilistic analysis or a cost-benefit analysis.[129] CAISO's assumption is not a choice driven by planning standards to which CAISO is subject. And CAISO's choice is therefore not one the Commission need, or should, accept. As a backup safety net, load shedding is a much more appropriate tool for addressing highly unlikely contingencies than burdening ratepayers with the expense of constructing major power plants to run for the next four decades, "just in case."[131] At a minimum, the San Diego SPS should be assumed to be in place as an interim measure throughout this LTPP study period while additional resources are developed.

F. Transmission Mitigation Options, Including Additional Reactive Support, Needs to Be Analyzed.

1. The Commission Should Defer its Decision Regarding LCR Need Until CAISO's Preliminary Transmission Plan Is Available.

CAISO, SCE and SDG&E all highlight the importance of potential transmission mitigation as key to any SONGS replacement strategy. CAISO originally recommended that the Commission defer any decision regarding procurement until CAISO has fully assessed possible transmission mitigations.[132] CEJA agrees with this recommendation. The Commission should not authorize procurement for additional generation resources in the absence of a thorough

[129] RT at p. 1611:26 – 1613:12(Millar, CAISO)

[131] CAISO's reluctance to use load shedding for severe contingencies and preference for more expensive options has been the subject of CPUC staff comments in the past. California Public Utilities Commission, Comments of the Staff of the California Public Utilities Commission on the January 31 2011 Draft of the 2011-2012 Transmission Plan, at 7-8 (Feb. 29, 2012), *available at* http://www.caiso.com/Documents/CPUC_Comments_Draft2011-2012_TransmissionPlan.pdf.

[132] Exhibit ISO-1 (Sparks Opening Testimony).

investigation of the available transmission upgrades and mitigations has not been conducted. Procurement authorization without full consideration other potential solutions would not be just and reasonable, and would potentially cost ratepayers billions of dollars.

2. If the Commission Declines to Wait for Complete Transmission Information, its Assumptions Should Include All Proposed Transmission Solutions Submitted by SCE and SDG&E to CAISO

If the Commission is inclined to proceed on incomplete information regarding transmission, CEJA recommends that the transmission projects proposed by SCE and SDG&E and discussed below be assumed completed by 2022. CAISO's study only included transmission upgrades and mitigations that are currently in place or already approved in its transmission plan.[133] This is inconsistent with Commission policy to evaluate all possible transmission operational solutions before procurement,[134] and may also lead to procurement that is not just and reasonable.[135]

SCE and SDG&E included potential transmission options in their studies that were not considered by CAISO. SCE examined the addition of the Mesa Loop-In project, which involves rebuilding and upgrading the existing Mesa 230 kV substation in the LA Basin to 500 kV and looping the Vincent-Mira Loma 500 kV line and 230 kV lines into the substation.[136] This project was submitted to CAISO as part of its 2013-2014 Transmission Planning Process. The Mesa Loop-In project would reduce generation needed in the LA Basin by approximately 1,200

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[133] Exhibit CEJA-2 (May Supporting Documents) at p. 32 (quoting CAISO's Transmission Plan at p. 28); *see also* Exhibit ISO-6 (CAISO Grid Planning Standards) (Chapter 3 from 2011-2012 Transmission Plan).
[134] *See supra* at Section I.A (discussing procurement requirements).
[135] Cal. Pub. Utilities Code § 399.11(d).
[136] Exhibit SCE-1 (Various Witnesses Opening Testimony) at p.17:4-8.

MW,[137] and this reduction should be assumed by the Commission if it makes any need determination before complete information is available.

Although SDG&E coordinated study efforts with SCE, SDG&E did not assess whether projects modeled in SCE's service territory would reduce need in San Diego.[138] However, SDG&E agreed that the need in San Diego could be reduced by projects developed by SCE.[139]

SDG&E examined the addition of two regional transmission projects that could reduce LCR need. The first project SDG&E included is a 500 kV Direct Current (DC) transmission project from Imperial Valley to SONGS.[140] The addition of a DC line would reduce the San Diego generation requirement by 850 MW and would reduce the generation requirement for the LA Basin by 551 MW.[141] The second project is a 500 kV regional transmission project from Devers Substation to a new 230 kV substation in north San Diego County.[142] This project reduced the LCR need for San Diego by 550 MW and reduced the LCR need for the LA Basin by 400 MW.[143] SDG&E witness Jontry noted that both of these projects "may differ slightly [from those submitted to the 2013/2014 Transmission Planning Process], but will be electrically equivalent."[144] SDG&E testified that it submitted two 500 kV options with different routing options from Imperial Valley to North County to CAISO's 2013-2014 Transmission Planning Process.[145]

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[137] Exhibit SCE-1 (Various Witnesses Opening Testimony) at p. 36:15-17.
[138] RT p. 1747:5-1748:6 (Jontry, SDG&E).
[139] RT p. 1747:5-1748:6 (Jontry, SDG&E).
[140] Exhibit SDG&E-3 (Jontry Opening Testimony) at p. 8:20-9:4.
[141] Exhibit SDG&E-3 (Jontry Opening Testimony) at p. 13:6-10.
[142] Exhibit SDG&E-3 (Jontry Opening Testimony) at p. 9:5-12.
[143] Exhibit SDG&E-3 (Jontry Opening Testimony) at p. 13:17-21.
[144] Exhibit SDG&E-3 (Jontry Opening Testimony) at p. 9: 2-4, 9:10-12.
[145] RT at 1749:3-11 (Jontry, SDG&E).

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In addition to projects that were included in the SCE/SDG&E study, SDG&E submitted a flow control device to CAISO for the 2013-2014 Transmission Planning Process.[146] Specifically, SDG&E requested "a phase shifter [that] would control the flow on the 230 kV system in Imperial Valley system in Imperial Valley between the ISO system and IID and CFE."[147] The addition of a phase shifter could reduce LCR need by approximately 500 MW.[148] SDG&E anticipates that a phase shifter could be online sometime between 2015 and 2017.[149]

The total increase in import capability and the resulting reduction of need provided by these transmission projects amounts to 3100 MW, not including the value of additional reactive support also contemplated by SCE, SDG&E and CAISO. When the need reduction provided by reactive support projects presently under consideration (as discussed below, roughly 300 MW in the LA Basin and 200 MW in San Diego), transmission options reduce need in the SONGS study area by approximately 3,600 MW.

3. The Commission Should Consider Reactive Power Options In Determining LCR Needs Created by SONGS Retirement.

The constraint that drives LCR resource need for the SONGS area is post-transient voltage instability under a N-1-1 contingency scenario. Reactive resources in the SONGS area are critical for avoiding voltage instability in the event of the driving contingency events, the loss of major transmission lines into the SONGS area.[150] The Revised Scoping Memo notes that it "sets forth the assumptions to be used for considering the impacts of interim and long-term local reliability needs in the Los Angeles Basin local area and San Diego sub-area resulting from

[146] RT 1748:18-1749:14 (Jontry, SDG&E).
[147] RT 1749:5-8 (Jontry, SDG&E).
[148] Exhibit CEJA-1 (May Opening Testimony) at p. 31.
[149] RT 1750:9-14 (Jontry, SDG&E).
[150] Exhibit ISO-1 (Sparks Opening Testimony)

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an extended SONGS outage," but the Scoping Memo does not list reactive power assumptions.[151]

CAISO has included some, but not all, resources with potential to mitigate the loss of reactive support provided by SONGS in its Track 4 analysis, and recognizes and anticipates that additional reactive resource analysis will be conducted as part of the 2013/14 TPP analyses. The Johanna, Santiago, and Viejo shunt capacitors are completed and included in CAISO's modeling.[152] The Huntington Beach synchronous condensers are also completed.[153] However, while the Huntington Beach condensers are assumed by CAISO to be available in the 2018 SONGS-out assessment, they are not included in the Track 4 2022 assumptions.[154]

SDG&E has proposed two 230 kV synchronous condenser projects that provide 480 MVARs of dynamic reactive support within the SONGS study area.[155] A rough estimate of the total need reduction in the San Diego area resulting from these projects is at least 200 MW.[156] SCE has proposed adding another 550 MVAR [Static Var Compensators] at San Onofre.

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[151] Scoping Memo, at p. 6.

[152] Exhibit CEJA-2 (May Supporting Documents) at pp. 48-50 (California Independent System Operator, Response of the California Independent System Operator Corporation to the First Set of Data Requests Related to Track 4 of the Division of Ratepayer Advocates; California Environmental Justice Alliance; Sierra Club, CA; and Clean Coalition, Request No. 2 (July 12, 2013)).

[153] Exhibit CEJA-1 (May Opening Testimony) at p. 8.

[154] Exhibit ISO-1 (Sparks Opening Testimony) at p. 9; Exhibit CEJA-2 (May Supporting Documents) at pp. 48-50 (California Independent System Operator, Response of the California Independent System Operator Corporation to the First Set of Data Requests Related to Track 4 of the Division of Ratepayer Advocates; California Environmental Justice Alliance; Sierra Club, CA; and Clean Coalition, Request No. 1 (July 12, 2013)).

[155] Exhibit SCE-1 (Various Witnesses Opening Testimony) at p. 28:5-15, t. III-3. These projects included a Suncrest 240 MVAR synchronous condenser and a Cannon/Encina 240 MVAR synchronous condenser. See also p. 31, Table III-4 notes.

[156] Exhibit CEJA-1, (May Opening Testimony) at p. 9.

CAISO estimates that this addition will reduce need in the LA Basin by 300MW.[157] This reactive support was not included in the 2022 results of CAISO's Track 4 Opening Testimony.

CAISO has stated that it only approved reactive support additions at two substations out of the ones analyzed because it did not know at the time of the Transmission Plan that SONGS was being permanently retired.[158] Both SCE and SDG&E concur that reactive support and transmission improvements are key to replace SONGS.[159] Because reactive support is so important for mitigating the SONGS retirement and not all available and practical solutions have been modeled, it is only reasonable that these be included and modeled, and the procurement decision be delayed until afterward. If the Commission is not willing to wait for a complete study of these proposed projects, it should assume that they are in place by 2018.

G. The Commission Should Account for 612 MW of Energy Storage from the Energy Storage Decision when Determining the Available Need in the SONGS Area

On October 17, 2013, the Commission issued its "Decision Adopting Storage Procurement Framework and Design Program."[160] In that decision, the Commission set energy storage targets of 580 MW for SCE and 165 MW for SDG&E.[161] These targets are to be procured gradually through biennial solicitations from 2014 through 2020.[162] Though the IOUs

[157] Exhibit CEJA-1 (May Opening Testimony) at p. 7.

[158] Exhibit CEJA-1 (May Opening Testimony) at p. 9, fn. 31. (California Independent System Operator, ISO Response to the Second Set of Data Requests Related to Track 4 of the Division of Ratepayer Advocates; California Environmental Justice Alliance; Sierra Club, CA; and Clean Coalition in Docket No. R.12-03-014, Request No. 3 (Aug. 8, 2013) ("[t]ransmission projects at two locations (vicinity of San Onofre switchyard, and Talega Substation) received the ISO Board approval as part of the least-regret transmission for the mid-term SONGS absence as part of the 2012/2013 Transmission Plan.")).

[159] *See e.g.*, SCE Track 4 Testimony, at 49:6-9; SDG&E Jontry Track 4 Testimony 7:14-19, 14:9-11.

[160] D.13-10-040.

[161] *Id.* at Appendix A, p. 2, Section 2(a).

[162] *Id.* at Appendix A, p. 5, Section 3(a).

may defer up to 80% of their MWs to later procurement periods,[163] they must ultimately have 100% of their respective storage targets online no later than December 31, 2024.[164]

As the Decision makes evident, storage can and will play a key role in the future of California's electricity grid: "[e]nergy storage has the potential to transform how the California electric system is conceived, designed and operated. In so doing, energy storage has the potential to offer services needed as California seeks to maximize the value of its generation and transmission investments; optimizing the grid to avoid or defer investments in new fossil fuel-powered plants integrating renewable power, and minimizing greenhouse gas emissions."[165] Moreover, consistent with AB 2514,[166] the Storage Decision guided by three purposes:

> The optimization of the grid, including peak reduction, contribution to reliability needs, or deferment of transmission and distribution upgrade investments;
>
> The integration of renewable energy; and
>
> The reduction of greenhouse gas emissions to 80 percent below 1990 levels by 2050, per California's goals.[167]

It is true that the targets in the Storage Decision need not be fully met until 2024 while this current LTPP proceeding only contemplates the needs of the electrical grid through 2022; but with storage procurement complete by 2020 and energy storage deploying relatively

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[163] *Id*. at Appendix A, p. 3, Section 2(c).
[164] *Id*. at Appendix A, p. 1, Section 2(a) ("Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company shall procure (i.e., pending contract, under contract, or installed) 1,325 MW of energy storage by 2020 with the requirement that the overall procurement goal of 1,325 MWs will be installed and delivering to the grid by no later than the end of 2024….").
[165] R.10-12-007 at p. 2.
[166] *See*: Cal. Pub. Util. Code § 2835(a)(3).
[167] D.13-10-040 at Appendix A, p. 1, Section 1.

quickly,[168] most if not all of the storage targets should be available by 2022. Therefore, since the Storage Decision has positive, long-term impacts on the environment and grid reliability in a timely manner, CEJA recommends that the Commission include the entirety of SCE's and SDG&E's energy storage targets within the SONGS area when making its final decision in Track 4.

The SONGS study area, however, does not include the entire SCE service area: in this and other proceedings, the LA Basin has been judged to comprise approximately 77% of this area.[169] Applying that number to SCE's 580 MW storage target for 2024 yields 447 MW of energy storage in the LA Basin; add that to SDG&E's 165 MW target and the total for the SONGS study area comes to 612 MW to be procured by 2020 and in operation by 2024. CEJA recommends the Commission utilize these 612 MW.

CAISO, SCE, and SDG&E do not oppose the deployment of energy storage within the SONGS service area (or outside it for that matter); however they do express concerns about its effectiveness for LCR purposes. CAISO, for example, presumes "the Commission will consider energy storage targets identified in…R.10-12-007 [Energy Storage Decision]" but is concerned about "the ultimate amount, location and timing of energy storage actually developed."[170] SCE similarly suggests that some portion of the targeted storage resources will end up in the LA Basin as LCR, but the "timing is unknown. It's not clear to me…what the accounting will be for LCR purposes of storage."[171] Likewise, "SDG&E believes that some amount of ES – the right kind of

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168 Exhibit CEJA-1 (May Opening Testimony) at p. 54

169 See e.g Scoping Memo, Attachment A at p.4; Exhibit CEJA-1 (May Opening Testimony) at p. 46.

170 CAISO Comments in Reponse to Questions Raised by ALJ Gamson during the September 4, 2013 Pre-hearing Conference, filed September 30, 2013ALJ Comments, at p. 3.

171 RT at 1903:9-18 (Nelson, SCE).

ES at the right locations – may play a role in meeting some of SDG&E's identified LCR need. SDG&E does not expect, however, that ES procurement to meet the [Storage Decision's] targets will translate directly into procurement capable of meeting LCR need on a megawatt-for-megawatt basis."[172] These concerns, though understandable, are unnecessary.

The targeted storage in D.13-10-040 is intended to "reduce demand for peak electrical generation, defer or substitute for an investment in generation, transmission, or distribution assets, or improve the reliable operation of the electrical transmission or distribution grid."[173] The utilities will not be able to satisfy these requirements unless they procure storage located in areas with demand for peak power, areas where investments in generation, transmission or distribution would occur, or areas with grid reliability issues. In SDG&E's territory, the only area currently identified that shares all these attributes is the San Diego local area.[174] In SCE's territory, the applicable area would appear to primarily be the Western LA Basin.[175] As such, if the IOUs locate their targeted storage using these guidelines, their concerns about LCR need should be allayed.

While the IOUs have expressed some uncertainty as to whether all of the energy storage procurement authorized in the Storage Decision will be capable of meeting local reliability needs (as discussed above), it seems clear that a substantial amount of energy storage procured to meet the targets set in R.10-12-007 will be available to meet such needs. Indeed, SDG&E recognized

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[172] Exhibit SDG&E-2 (Anderson Rebuttal Testimony) at p. 1:18-21.

[173] Cal. Pub. Util. Code § 2835(a)(3).

[174] A.13-06-015, Application of San Diego Gas & Electric Company (U 209 E) to Fill Local Capacity Requirement Need Identified in D.13.03.029 (June 21, 2013) at pp. 2-3.

[175] RT at 1900:8:13 (Nelson, SCE) ("…I do think you're right that it is in fact divided between a focused portion in South Orange County and then the rest just in the Western L.A. Basin so that it would count for LCR.").

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that some portion of storage should be able to meet LCR need.[176] If the Commission believes this is a genuine issue, it could consider asking the IOUs to assure that their RFOs for storage specify characteristics necessary to meet LCR need, as suggested by SDG&E.[177] However, simply ignoring the substantial likelihood that such clean and flexible resources will be available for local reliability purposes has potential to cause over-procurement and/or to undermine the Commission's goals with respect to energy storage development.

SCE has expressed concern that energy storage will not be "cost-effective" as required in AB 2514.[178] According to SCE, they estimate the capital cost for a 10 MW battery facility to be $1,983/kW with four hours of storage capacity while assuming battery replacement every ten years.[179] However, a four-hour battery replacement is excessive for local capacity purposes. For example, CAISO wholesale day-ahead demand response products must be able to respond to an event of up to 2 hours duration.[180] There is a substantial difference in the capital cost of 2- and 4-hours of battery storage.[181] The Sierra Club, on the other hand, noted that the Commission itself "estimates the 2020 capital cost of 50 MW of battery storage with 2 hours of storage capacity at $1,056/kW, and with 3 hours of storage capacity at $1,406/kW. The Commission estimates the 2020 capital cost of LMS100 units at $1,535kW."[182] Additionally, SDG&E has stated that as the development of storage technology continues to progress, it is likely that prices

176 RT at pp. 1810:22 – 1811:14 (Anderson, SDG&E).

177 RT at pp.1855:26 – 1856:2 (Anderson, SDG&E) ("I think we ought to go out in an RFO seeking energy storage with the characteristics we need to meet the LCR need. So that way we identify the need, and we look for the storage to be part of the solution.").

178 RT at p. 2156:18-24 (Silsbee, SCE).

179 Exhibit SC-1 (Powers Opening Testimony) at p. 24.

180 *Id*.

181 *Id*.

182 *Id*. (Footnotes removed).

will decline over time.[183] Given the Commission's own studies showing that energy storage as well the assertions of another utility, any worries about whether energy storage will be cost-effective should be dismissed.

Therefore, for the reasons stated above, the Commission should include 612 MW of energy storage from the Energy Storage Decision when making its determination of need in Track 4.

H. Each Study Undercounts Available Preferred Resources

1. CAISO's Study Undercounts Preferred Resources Included In The Scoping Memo as "Second Contingency" Resources

The Scoping Memo sets out assumptions for Demand Response and Incremental Small Photovoltaic Installed Capacity for 2018 and 2022. The demand response assumptions are the same for both years, 189 MW of "fast" DR to be modeled as a "First Contingency" resource and 997 MW of DR forecasted in the Load Impact Report which is to be accounted for as a "Second Contingency Resource." According to the Scoping Memo, the studies "shall model 'First Contingency' resources as addressing the first contingency to prepare for the second contingency."[184] Second Contingency resources "are not modeled but would be accounted for as potential resources to address any residual need identified by a second contingency condition in the studies."[185] Price responsive and day-ahead DR programs or DR programs outside the areas of most concern fit the Second Contingency category.[186] The Scoping Memo states an expectation that these programs could become more capable of meeting needs by 2022 while

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183 Comments of the California Environmental Justice Alliance in Reponse to Questions Raised by ALJ Gamson during the September 4, 2013 Pre-hearing Conference, filed September 30, 2013, at p. 5, referring to Opening Comments of San Diego Gas & Electric Company Concerning Proposed Decision in R.10-12007 dated 9-23-2013 at p. 4.

184 Scoping Memo, Attachment A at p. 2.

185 *Id*.

186 *Id*.

also noting that further action would be needed to make that a reality, and that the study results "shall provide a broad assessment of local area needs that inform the programs of 'Second Contingency' resources such that they can adapt to meet the residual need."[187]

Similarly, the Scoping Memo designates incremental customer-side PV as a Second Contingency resource because it is difficult to predict the location where customer-side PV will get built. The Scoping Memo directs CAISO to determine the most effective busbars where customer-side PV should be located in order to address those contingencies: "[o]nce those locations are identified, the Commission can then direct customer-side generation programs, like the California Solar Initiative or other efforts, to target those locations."[188]

The only other resources designated by the Scoping Memo as Second Contingency are those authorized in prior proceedings, including the Track 1 authorization to SCE of 1400-1800 MW of procurement and 298 MW approved in the San Diego PPTA Decision.[189] Those resources, like the incremental small PV, were categorized as Second Contingency because of locational uncertainty.[190]

CAISO treated the three sets of Second Contingency resources quite differently. It directly reduced its calculation of residual need by 1800 MW for the LA Basin and 308 MW for San Diego based on the Track 1 and San Diego authorizations.[191] It modeled 198 MW of "post first contingency". It did not reduce need at all to account for the 997 MW of Second Contingency DR. Rather, CAISO stated that this 997 MW "would be applied to contingencies that are of Category D." Similarly, CAISO relegated incremental customer side PV to

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187 *Id.*

188 *Id.* at p. 10.

189 *Id.* at p. 13. Attachment A to the Scoping Memo actually refers to D.12-12-010 rather than D.13-02-015, but the only authorization of 1400-1800 MW to SCE occurred in the latter proceeding. CEJA assumes this was a typographical error and notes that CAISO made the same assumption in its analysis.

190 *Id.*

191 CAISO included a 10 MW of net increase for Escondido. See Exhibit CAISO-1 (Sparks Opening Testimony) at p. 26, Table 13.

addressing Category D contingencies, i.e. contingencies that CAISO says are not included in this study and are irrelevant to this proceeding.

a. Second Contingency DR

CAISO's treatment of Second Contingency DR is problematic for two reasons. First, CAISO appears to assume that the character of the demand response programs that exist today are the same as will exist in 2022, which seems to contradict the expectation stated in the Scoping Memo that those programs are likely to be able to meet need in 2022 if action is taken.[192] Secondly, on September 25, 2013 the Commission instituted a rulemaking proceeding intended to enhance the role of DR programs. The OIR for that proceeding makes it very clear that the Commission does not intend for demand response programs to remain in stasis for the next 9 years:

> None of the 2,400 MW from the Utilities' retail demand response programs participated in the CAISO markets in 2012 and the CAISO's ability to dispatch these demand response resources continues to be limited. . . .
> The Commission is hopeful that the new vision for demand response resources in this rulemaking and the increasing collaboration among the state agencies will help California overcome these challenges.[193]

In particular, the current DR proceeding is likely to increase the role of DR in the SONGS study area. In its order, the Commission found that, historically, SCE and SDG&E have underutilized demand response programs and dispatched their power plants to meet peak demand far more frequently in comparison to demand response programs.[194] The demand response programs were not utilized to their full Resource Adequacy capacity even during extremely hot

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[192] Scoping Memo, Attachment A, at p. 2.
[193] R.13-09-011 Order Instituting Rulemaking dated September 25, 2013 at p. 14-15.
[194] *Id*. at 7.

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weather conditions such as are found in the Track 4 modeling.[195] It is reasonable to expect that DR programs in the region will expand and become more focused by 2022.

Second, even if the character of the programs identified as Second Contingency resources do not change, they still have value in addressing the contingency modeled here. CAISO has assumed that the N-1-1 contingency involved occurs at the hour of peak demand on the hottest day in ten years. The DR resources characterized as Second Contingency are capable of being scheduled in advance, and in the case of such a notably hot day they would have sufficient notice (presumably in the form of a weather forecast) to be scheduled in advance. By drawing down on these programs, the Second Contingency DR would shave load and reduce need. CAISO witness Millar confirmed this fact during the hearing:

> Q. Would a long start generator that's off-line when an N-1 -- this is a hypothetical -- contingency occurs be able to respond in 30 minutes?
>
> A. I think you've answered your question. No.
>
> Q. Okay. But isn't that generator in the LA Basin still considered a local capacity resource?
>
> A. It is. But the difference here is that if we knew we were going to be entering into a high load period, we would commit the unit so that it is started and operating.
>
> Q. Isn't it possible that a demand response resource with more notice [would] also be able to respond within the time frame expected?
>
> A. That's possible.[196]

Whether one assumes that the nature of the Second Contingency DR has evolved sufficiently (with the Commission's help) to meet LCR needs by 2022 or simply that it remains an option to shave load on an easily anticipated high-load day, the 997 MW of Second

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195 *Id*.
196 RT at p. 1692:1-18 (Millar, CAISO).

Contingency DR should reduce need. CAISO's relegation of the entire amount to address a Category D contingency for which it is not even required to plan is inappropriate.

b. Incremental small PV

Similarly, CAISO did not reduce its residual need calculation to account for customer side PV, using the rationale that its location "is difficult to determine and therefore should be considered located in the most effective locations, similar to the additional larger amount of DR, for mitigating reliability concerns associated with contingencies that are subsequent to second contingency conditions (i.e. post second contingency) following an N-1-1- overlapping contingency." The Scoping Memo states that CAISO is to determine the most effective locations so the Commission can then direct customer-side generation programs to target those locations. By 2022, with the likely implementation of smart inverters and a smarter grid in general, distributed generation such as customer side PV will provide manageable power located in the affected area that can reduce peak loads, reduce transmission line loss, and provide ancillary services such as reactive power and voltage support. Relegating it to addressing a Category D contingency, a contingency not even being studied here, is – again – inappropriate.

CEJA submits that CAISO's residual need calculation should be reduced by all of the Second Contingency resource amounts, not just those which CAISO believes are worthy of consideration.

2. SCE's Study Does Not Reflect Available Preferred Resources

SCE stated in testimony that "[t]o the extent practical, SCE relied on the Revised Scoping Ruling and Memo of the Assigned Commissioner and Administrative Law Judge issued on May 21, 2013."[197] However, SCE did not rely on the scoping assumptions at all with respect to preferred resources. SCE assumed no energy efficiency, DG, or PV other than what is embedded within the CEC demand forecast. Demand Response is not used in the load forecast.

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197 SCE Track 4 Testimony, at 13 (emphasis added).

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The only preferred resources not embedded in the load forecast were set forth in SCE's Preferred Resources Scenario, which includes increased levels of energy efficiency, demand response, energy storage, and customer side PV.[198] SCE concluded the assumptions set forth in the Scoping Memo were only for CAISO to use.[199]

In SCE's Preferred Resources Scenario,[200] it included 50 MW of Energy Storage, 126 MW of Rooftop Solar, and 452 MW of DR, totaling 628 MW of these preferred resources. The CPUC assumptions, on the other hand, included 50 MW of Energy Storage, 390 MW of Rooftop Solar (171 NQC for 2018 + 219 NQC for 2022), and 794 MW of DR, totaling 1,234 MW, which is 606 MW more than SCE used in its Preferred Resources scenario and 1,234 MW more than any of its other scenarios. The difference between SCE's assumptions and the Scoping Order alone offsets SCE's procurement request of 500 MW. Moreover, SCE has not accounted for any portion of the 580 MW of energy storage the Commission ordered it to procure in D.10-12-007; it only accounted for the 50 MW ordered procured in Track 1. Consideration of the additional storage procurement, which will be substantially in place by 2022, reduces SCE's need even more.

3. SDG&E

SDG&E found about 620 MW of need after application of transmission solutions[201] and then asked for a slightly lower amount of procurement (about 500-550 MW), based on the idea that it had not accounted for any DR and/or other preferred resources. This means SDG&E assumed 70-120 MW of DR and/or other preferred resources would be in place. The Scoping

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198 SCE Response to CEJA, DRA, and Sierra Club, DATA REQUEST SET CEJA_DRA_Sierra Club-SCE-001, Question 2 (emphasis added).

199 SCE Response to CEJA, DRA, and Sierra Club, DATA REQUEST SET CEJA_DRA_Sierra Club-SCE-001, Questions 3-5.

200 SCE Track 4 Testimony, at 18, table III-1.

201 Exhibit SDG&E-1 (Anderson Opening Testimony) at p. 11.

Memo assumes a total of 16 MW in First Contingency DR[202] and an additional 203 MW of Second Contingency DR for a total of 219 MW.[203]

SDG&E assumed only 20 MW of dependable capacity from new local solar based on an installed capacity of 50MW in the load pocket.[204] Not only is this less than half the amount requested in the Scoping Memo (45 MW in 2018 and 59 MW in 2022), but the 60% reduction from 50 MW installed capacity does not even use the Scoping Memo's peak demand import factor of 0.46.[205] SDG&E's modeling also does not include any of the 165 MW of energy storage it was ordered to procure by 2020 in D.10-12-007. As with SCE, consideration of the additional storage procurement will reduce SDG&E's need even more.

IV. THE CONTINGENCY PLANS PROPOSED BY SCE AND SDG&E ARE UNNECESSARY AND INAPPROPRIATE

SCE has proposed two forms of contingent planning to "backstop" its plans to incorporate preferred resources and to account for possible problems with construction of new generation facilities. One plan involves the use of contingent contracts for power while the other involves contingent site permitting. SDG&E has proposed to develop an "Energy Park," which appears to be a pre-developed site for new gas fired generation, also justified as contingency planning. While none of these proposals are actually before the Commission in this proceeding, CEJA submits that all of these plans are unnecessary. There are other options for contingency planning than new gas power plant construction. One such option has already been discussed,

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202 This assumption appears understated, as SDG&E reports that it already has 20 MW of fast DR in place. *See* Exhibit SDG&E-1 (Anderson Opening Testimony) at p. 12, n. 12.

203 SDG&E currently has 40-45 MW of DR in place in addition to the above-mentioned 20 MW of fast DR. *See* RT at pp. 1805:5-12 and 1806:27 – 1807:3 (Anderson, SDG&E).

204 Exhibit SDG&E-1 (Anderson Opening Testimony) at p. 8:9-11.

205 Scoping Memo, Attachment A, p. 9.

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the use of the San Diego SPS as an interim measure while other resources are under development.

To the extent the Commission believes that there may be uncertainties whether resources such as improved demand response, distributed generation, and energy storage required by the recent storage decision will be available in 2022, CEJA recommends that the Commission seek short-term (2-4 year) extensions of OTC retirement dates in order to alleviate that concern. From a water quality perspective, the impacts of such extensions would be minor. SONGS was responsible for approximately 90 percent of Southern California power plant OTC water withdrawals prior to its June 2013 retirement. It retired ten years before the State Water Board-mandated OTC retirement schedule. This is also far more reasonable from a greenhouse gas and air quality perspective, an additional five years of OTC operation, compared to committing to another four decades of fossil-fuel generation. Finally, it is extremely effective from a ratepayer perspective – it is far more expensive to build new or even repowered gas plants that will not be able to run due to future environmental restrictions than to extend existing facilities and replace them with preferred resources.

CONCLUSION

For the reasons stated above, CEJA urges the commission to find that there is no need for procurement of new resources in the SONGS study area at this time, and to deny the request of SCE and SDG&E for such procurement.

Respectfully submitted,

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