ATTACHMENT B

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

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

APPLICATION BY THE PROTECT OUR COMMUNITIES FOUNDATION FOR REHEARING OF DECISION 14-03-004

David A. Peffer, Esq.
PROTECT OUR COMMUNITIES FOUNDATION
4452 Park Boulevard, Suite 209
San Diego, CA 92116
Email: david.a.peffer@gmail.com

Attorney for the Protect Our Communities Foundation

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I. INTRODUCTION

Pursuant to Rule 16.1 of the Commission's Rules of Practice and Procedure and Public Utilities Code Section 1731 the Protect Our Communities Foundation ("POC") submits the following Application for Rehearing of Decision 14-03-004 ("the Decision").

Relying on models provided by the California Independent System Operator ("CAISO"), one of the parties to this proceeding, the Decision concludes that 2,390 new MW of electrical power is needed throughout the private utilities' service areas by 2022 to meet expected demand. The Decision allocates need among the utilities service areas as follows:

- The Decision authorizes Southern California Edison Company ("SCE) to procure between 1,900 Megawatts (MW) and 2,500 MW of electrical capacity in the Los Angeles Basin local capacity area[1] in combination with procurement authorizations totaling 1,400 to 1,800 MW to meet long-term local capacity requirements by the end of 2021 (Decision, p. 141 citing Ordering Paragraph 1 of D.13-02-015). At least 1,000 MW, but no more than 1,500 MW, of this SCE local capacity must be from conventional gas-fired resources, including combined heat and power resources.
- The Decision authorizes San Diego Gas & Electric Company ("SDG&E") to procure between 500 MW and 800 MW of electrical capacity in its territory to meet long-term

[1] A Local Capacity Area or "LCR"is a defined local area that requires a minimum local electricity supply resource capacity to meet established grid reliability criteria.

local capacity requirements by the end of 2021, of which at least 200 MW must be non-natural gas-fired resources (at p. 143).

This Application sets forth the following grounds on which the Decision is unlawful or erroneous:

- The Decision arbitrarily and without foundation in the record evidence substantially discounts the availability of preferred resources, including Demand Response, Energy Efficiency, Solar PV, and Energy Storage, in determining the amount of LCR need. In so doing, the Decision overvalues the amount of need and authorizes over-procurement of additional resources, particularly gas-fired resources, in contravention of a variety of state laws and policies that require new demand to be met on a priority basis with renewable resources and mandate that the Utilities meet certain targets for renewable resources, including but not only Public Utilities Code Sections 454.5(b)(9)(c), 2827(c)(4)(B), and 2835, et setthe State's Energy Action Plan, and the Commission's own Loading Order. Thus, the Decision fails to proceed in the manner required by law in contravention of Public Utilities Code section 1757(a)(2).
- The Decision also overvalues the amount of LCR need and authorizes over-procurement by failing to consider the full capacity of existing or very likely to be available non-gas-fired generation grid support projects and continued operation of existing gas fired generation. The Decision's failure to consider the full capacity of these non-preferred resources, as well as its discounting of preferred resources, has no basis in the record and findings and thus violates Public Utilities Code Sections 1757(a)(3) and (4), which require that the Commission support its decision with findings on every material issue and base its findings on substantial evidence. Because the over-procurement authorized by the Decision will cause unnecessary rate increases, the Decision further violates the Commission's duty under Public Utilities Code Section 451, which requires that "all charges demanded or received by any public utility… shall be just and reasonable," and Section 454, which provides that "a public utility shall not change any rate or so alter any classification, contract, practice, or rule as to result in any new rate, except upon a showing before the commission and a finding by the commission that the new rate is justified." Accordingly, the Decision's discounting of preferred resources and failure to consider the full capacity

of non-preferred resources constitutes a failure by the Commission to proceed in the manner required by law and an abuse of the Commission's discretion under Public Utilities Code Sections 1757(a)(2) and (a)(5).

∞ In addition, the Decision's entire needs assessment is driven by the Decision's reliance on CAISO's determination that the Sunrise Powerlink/Southwest Powerlink (Sunrise/SWPL) N-1-1 event is the appropriate limiting critical contingency for the San Diego local area. The Decision's deference to CAISO on this issue despite the existence of uncontradicted evidence that this N-1-1 event is so unlikely to occur that it need not be mitigated under governing law violates the Commission's duty under Public Utilities Code Sections 1757(a)(3) and (4) to make findings on every material issue and base its findings on substantial evidence in the record. It also constitutes an unlawful delegation of the Commission's regulatory authority, a failure by the Commission to consider a material issue of public interest, in contravention of Public Utilities Code Section 1705, and a violation of the due process rights of parties as guaranteed by the United States Constitution and the California Constitution. to a full and fair hearing on this issue [2] Because acceptance of the Sunrise/SWPL N-1-1 event as the critical contingency results in an assessment of need that otherwise would not exit, it further violates the Commission's duty to ensure just and reasonable rates under Public Utilities Code Sections 451 and 454. As such, in using the Sunrise/SWPL N-1-1 contingency to determine need, the Commission has failed to proceed in the manner required by law and abused its discretion under Public Utilities Code Sections 1757(a)(2) and (5)

∞ Relatedly, the Decision's denial of POC's motion for official notice of documents establishing that governing regulations do not require treating the Sunrise/SWPL N-1-1 event as a limiting critical contingency, and the Decision's striking of POC's opening and reply briefs based on their citation of these documents, also constitutes a failure by the Commission to proceed in the manner required by law under Public Utilities Code Section 1757(a)(2), a failure by the Commission to make findings based on substantial evidence under Public Utilities Code Section 1757(a)(4), a

[2] *City of Los Angeles v. Public Utilities Com.* (1975) 15 Cal.3d 680, 694; quoting *Northern California Power Agency v. Public Util. Com.* (1971) 5 Cal.3d 370, 380

violation of POC's due process rights under the United States and California Constitutions, and an abuse of the Commission's discretion under Public Utilities Code Section 1757(a)(5).

- Finally, the Decision's authorization of procurement by the Utilities through bilateral contracts is inconsistent with the various state laws and policies requiring that future need be addressed on a priority basis by preferred, renewable resources rather than gas-fired resources, and inconsistent with the Commission's duty to assure just and reasonable rates under Public Utilities Code Sections 451 and 454. As such, by authorizing bilateral contracts the Commission has failed to proceed as required by law and abused its discretion under Public Utilities Code Sections 1757(a)(2) and (a)(5).

The Commission should expeditiously grant rehearing of the Decision in order to correct these legal errors.

II. THE DECISION ERRS IN USING AN UNSUPPORTED AND ARBITRARY APPROACH TO DISCOUNT PREFERRED RESOURCES IN DETERMINING LCR NEED

A. More Than Sufficient Non-Fossil Fuel Resources Are Available to Meet the Identified Need, But The Decision Largely Discounts These Resources Based on Arbitrary and Unsupported Methodologies.

California statutes and Commission policy prioritize the use of clean, non-fossil fuel "preferred resources" to meet new electricity demand. As the Decision recognizes:

> The Commission . . . has a statutory mandate to implement procurement-related policies to protect the environment. Section 454.5(b)(9)(C)[3] states that utilities must first meet their "unmet resource needs through all available energy efficiency and demand reduction resources that are cost-effective, reliable and feasible." Consistent with this code section, the Commission has held that all utility procurement must be consistent with the Commission's established Loading Order, or prioritization.[4]

[3] Unless otherwise noted, all further statutory references in this Application for Rehearing are to the Public Utilities Code.
[4] Decision, pp. 13-14.

> Preferred Resources are defined in the State's Energy Action Plan II, at 2, as follows: "The loading order identifies energy efficiency and demand response as the State's preferred means of meeting growing energy needs. After cost-effective efficiency and demand response, we rely on renewable sources of power and distributed generation, such as combined heat and power applications. To the extent efficiency, demand response, renewable resources, and distributed generation are unable to satisfy increasing energy and capacity needs, we support clean and efficient fossil-fired generation . . . in this decision, we also include Energy Storage in the category of Preferred Resources for ease of use unless otherwise noted.[5]
>
> Once procurement targets are achieved for preferred resources, the IOUs [Investor Owned Utilities] are not relieved of their duty to follow the Loading Order. In D.07-12-052 at 12, the Commission stated that once demand response and energy efficiency targets are reached, "the utility is to procure renewable generation to the fullest extent possible." The obligation to procure resources according to the Loading Order is ongoing.[6]

In this proceeding, parties identified several non-fossil fuel resources that were not included in CAISO's modeling of LCR resources. These resources are listed in Table 1:[7]

Table 1. Resources Not Included in CAISO Modeling

	Impact On Need
Temporary Load-Shedding	- 588 MW
Mesa-Loop in Transmission Project	- 734 MW
Uncommitted Energy Efficiency (EE)	- 733 MW
Energy Storage	- 745 MW
Second contingency Solar PV	- 800 MW
Second contingency Demand Response (DR)	- 997 MW

If fully accounted for, these non-fossil fuel resources would provide a total of 4,597 MW, which is far more capacity than the 2,390 MW need identified by CAISO's modeling and accepted by the Decision.[8]

The parties offered credible and substantial evidence that these preferred resources will be in place at or near the quantities identified in Table 1 by 2022. However, the Decision largely discounts these resources, finding that they are not "very likely" to be available by 2022, and thus cannot be counted toward meeting LCR need, based on arbitrary conditions that have no

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5 Decision, p. 6, fn. 3 and Conclusion of Law 3, p. 135: "The Loading Order, first set forth in the Commission's 2003 Energy Action Plan, and presented in the Energy Action Plan II adopted by this Commission and the CEC in October 2005, established that the State, in meeting its energy needs, would invest first in energy efficiency and demand-side resources, followed by renewable resources, and only then in clean conventional electricity supply."
6 Decision, p. 14.
7 Decision, Table 2, at p. 73
8 Decision, p. 76.

basis in the law or the record and no effect on these resources' ability to meet the LCR need on a megawatt-to-megawatt basis. For example, the Decision requires that, to be counted, DR must be dispatchable within 30 minutes, and the exact location(s) of solar PV PV within the LCR area must be identifiable. Applying these arbitrary requirements with no basis in the evidentiary record and, in the case of energy storage, based simply on an ill-defined unease with the technology in general, the Decision assures that the preferred resources largely fail the "very likely" test.[9] Using this approach, the Decision qualitatively distinguishes between those resources that are "reasonably possible" to be in place, and those that are "very likely." Only those resources which the Commission deems "very likely" to be in place by 2022 are counted. The Decision applies this methodology to each preferred resource, and without record support finds that each preferred resource in the quantities listed in Table 1 fails to meet the "very likely" threshold.

In an alternative methodology, the Decision acknowledges that collectively *some* of these preferred resources may be in place by 2022. To account for this possibility, the Decision adds together all of the resources in Table 1, rounds the total up from 4,597 MW to 4,600 MW, and discounts this total by assuming *only one* of the resources listed in Table 1 will be developed. Using this approach, only 13 to 22 percent of the 4,600 MW in Table 1 is counted in the Decision toward meeting the LCR need.[10] Paradoxically, the Decision assumes *any one* of the preferred resources will be available megawatt-for-megawatt to reduce LCR need (i.e., be 100 percent available), but then only counts one of the resources, either DR or EE or solar PV or energy storage, ignoring the rest.

Both of the Decision's methodologies are deeply flawed. The Decision provides no support for its adoption and application of the "very likely" test. The test has no basis in statute, and the Decision provides no legal citations supporting the test. The Decision does not support this test by citation to any prior Commission decision, and POC is unaware of any prior Commission Decision where this test was adopted or applied. The test was not used in resolving the Track 1 authorization of the instant proceeding, which addressed the same resources: solar PV, demand response, EE, and energy storage.[11]

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[9] D.14-03-014, Finding of Fact 62, at p. 130. The highest reasonable LCR need level must take into account those resources which are very likely to be procured in the time frame between now and 2022.
[10] Decision, Finding of Fact 67, p. 131.
[11] D.13-02-015

The Decision's alternative methodology collectively discounting the resources in Table 1 is equally unreasonable, arbitrary, and lacking evidentiary support in the record of this proceeding. Findings of Fact 66-73 in the Decision[12] are proffered to support the position of the Decision that, despite controlling statutes[13] prioritizing preferred resources over all other resource types, preferred resources are largely unavailable to meet the identified LCR need. The net effect of these findings of fact, none of which has an evidentiary basis in the record, is to moderately trim the procurement authorizations recommended by CAISO, instead of discarding them altogether by validating the uncontested record evidence that available preferred resources can entirely meet the identified LCR need. [14]

The Decision presents its case for largely discounting the role of preferred resources to meet the LCR need based on no substantial evidence and unsupported qualitative judgments. The discounting methodologies applied in the Decision lack any basis in law and are not supported by the evidentiary record. By discounting thousands of MW of preferred resources and by authorizing utility procurement based on an LCR determination driven, in part, by adoption of arbitrary methodologies without any basis in law, the evidentiary record, or prior Commission practice, the Commission has failed to prioritize preferred resources, energy efficiency, and demand response over gas-powered procurement in violation of Section 454.5(b)(9)(c), the State's Energy Action Plan, and the Commission's own Loading Order. Further, the Commission has failed to ensure just and reasonable rates in violation of Sections 451 and 454, instead ensuring that ratepayers will now pay a second time for duplicate resources that will already be in place to meet the LCR need. As such, the Commission has failed to proceed as required by law, made findings unsupported by substantial evidence in the record, and abused its discretion, all in violation of section 1757(a).

[12] Decision, p. 131.

[13] Public Utilities Code Section 454.5(b)(9)(C), 2827(c)(4)(B), 2836(a), and 2837

[14] The Decision, in Finding of Fact 49, states that the energy storage targets adopted in D.1310-040 cannot be assumed to count toward meeting the LCR need on a megawatt-for-megawatt basis, and that potential amounts of demand response, energy efficiency or solar PV resources also cannot be assumed to count toward meeting the LCR need on a megawatt-for-megawatt basis. Finding of Fact 49 is unsupported in the evidentiary record of this proceeding. The record contradicts this finding of fact for each of thepreferred resources listed: demand response, energy efficiency, solar PV resources, and energy storage, as explained in the following sections. Thus, Finding of Fact 49 violates Sect. 1757.

B. The Decision Improperly Fails to Count 997 MW of Available Demand Response.

The Decision makes the following finding of fact concerning the availability of demand response (DR) resources:

> "Potential amounts of demand response. . . cannot be assumed to count toward meeting the LCR need on a megawatt-for-megawatt basis."[15]

This finding is not supported by substantial evidence in the record and is contrary to law.

The Decision's treatment of DR resources in SCE's LA Basin and SDG&E territory is driven by an arbitrary distinction between "first contingency" DR, defined as DR that can be called upon within 30 minutes, and "second contingency" resources. With no substantial evidence to make such a distinction in the definition of available resources, the Decision excludes 997 MW of DR. The Decision simply accepts CAISO's characterization of LCR capacity. Neither the Commission nor CAISO has ever defined LCR requirements for DR, much less defined them in such restrictive terms.[16] The distinction between first contingency and second contingency DR is arbitrary, given a primary purpose of DR is to reduce peak demand and it is reasonable to assume that SCE and SDG&E would be scheduling dispatch of all available DR to reduce peak load on a forecast 1-in-10 year weather event day. CAISO witness Millar testified that a slow-firing gas generation plant (such as a coastal OTC boiler plant) is considered a first-contingency resource despite requiring more than 30 minutes to call up, noting that in high load periods (such as the 1-in-10-year peak weather event modeled in this proceeding) CAISO would be able to commit the plant in advance. He admitted that the same could be true of DR programs.[17] Thus, whether a DR resource is a "first contingency" resource or a "second contingency" resource is an arbitrary distinction from the standpoint of the DR being available to reduce LCR need under an N-1-1 contingency.

EnerNOC introduced evidence that no other Independent System Operator (ISO) or Regional Transmission Operator (RTO) requires demand response resources to be dispatched within 30 minutes in order to qualify as a local capacity resource. Instead, to qualify, these DR resources simply need to be located in the local area and dispatched as instructed by the ISO or

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[15] Decision, Finding of Fact 49, at p. 129.
[16] The Track 1 Decision (D.13-02-015) left the definition of local capacity resource attributes to SCE and the CAISO to develop. Today, there is no adopted definition of the requirements DR resources would need to meet in order to satisfy the LCR. EnerNOC, Inc. Prepared Testimony of Mona Tierney-Lloyd at p. 11.
[17] RT at 1692 (CAISO, Millar).

RTO.[18] These EnerNOC statements were not contested. EnerNOC also questioned CAISO on the basis for discounting DR, for which the CAISO witness had no answer:[19]

> Q Has the CAISO or the Commission adopted a definition for DR resources qualifying as a local capacity resource, eligibility criteria, if you will?
> A We are -- well, one of the things I left out in my description of the ISO, current ISO planning process and the status of it which is a glaring omission is that we were also working on identifying the necessary characteristics of preferred resources such as demand response such that it can meet local needs.
> Q And that hasn't happened yet; is that correct?
> A It's in the process.

Finding of Fact 49 is not supported by substantial evidence and is arbitrary and capricious. By failing to account for 997 MW of DR based on an arbitrary distinction, and by authorizing utility procurement based on an LCR determination inflated, in part, by this failure, the Commission has failed to prioritize demand response over gas-powered procurement in violation of section 454.5(b)(9)(c), the State's Energy Action Plan, and the Commission's own Loading Order. The Commission also has failed to ensure just and reasonable rates in violation of sections 451 and 454. As such, the Commission has failed to proceed in the manner required by law in violation of section 1757(a)(2). Further, by adopting an arbitrary distinction for DR despite the strong evidence against it, including CAISO's own admissions, and the lack of evidence establishing that the distinction is valid or reasonable, the Decision has failed to support its findings with substantial evidence in violation of section 1757(a)(4) and abused its discretion in violation of section 1757(a)(5).

C. The Decision Improperly Fails to Count 773 MW of Highly Likely Energy Efficiency Savings.

The Decision makes the following finding of fact concerning the availability of energy efficiency resources:

> "Potential amounts of . . . energy efficiency . . . resources also cannot be assumed to count toward meeting the LCR need on a megawatt-for-megawatt basis."[20]

This finding is not supported by substantial evidence in the record and is contrary to law.

[18] EnerNOC Opening Brief, p. 16.
[19] Sparks hearing transcript, p. 1553: (response to EnerNOC on failure to define DR resources)
[20] Decision, Finding of Fact 49, at p. 129.

In calculating the LCR for the SONGS area, the Decision fails to include 733 MW of highly likely energy efficiency savings that were omitted from CAISO assumptions.[21] The 733 MW of energy efficiency (EE) at issue falls into two groups: (1) 576 MW of "naturally occurring" EE savings, i.e., EE savings that are expected to occur regardless of any program or policy,[22] and (2) 157 MW of EE savings from California Energy Commission (CEC) building efficiency standards set to take effect in 2017 and 2020, as well as other State and Federal EE codes and standards that will produce savings beginning in 2015.[23]

The Decision rejects the 576 MW of "naturally occurring" EE savings on two grounds, both relating to the feasibility and availability of these EE resources. First, the Decision claims that uncommitted EE values were based on a "draft" CEC staff forecast that was "not final."[24] This is a factual error, as "the 576 MW of 'naturally occurring' savings do not, as the Decision states, come from the September 2013 CEC draft forecast. Rather, they come from the CEC's *Estimates of Incremental Uncommitted Energy Savings Relative to the California Energy Demand Forecast 2012-2022*, a final report issued in September of 2012."[25]

Second, the Decision claims the LCR impact of uncommitted EE is too uncertain because "there is nothing in the record to show how or whether any such updates might impact LCR needs."[26] This is also in error. The Natural Resources Defense Council (NRDC) provided testimony indicating that the naturally occurring savings detailed in the report "yields 576 MW of additional local impacts from energy efficiency in the SONGS study area (LA Basin and SDG&E territory)."[27] NRDC's witness, Sierra Martinez, testified that NRDC did not merely assume a megawatt-for-megawatt impact on LCR need. Rather, NRDC calculated LCR reduction by utilizing the same methodology used in the Revised Scoping Memo and the busbar allocation methodology of the Energy Commission.[28] This testimony was uncontradicted. Thus, the evidence in the record shows that 576 MW of naturally occurring energy efficiency is very likely to reduce LCR need in the SONGS study area and should therefore be count to reduce overall procurement. The Commission erred in failing to take this available energy efficiency

[21] CEJA Opening Brief, at p. 22; NRDC Opening Brief, at p. 5.
[22] Ex. NRDC-1 (Martinez Opening Testimony), at p. 10.
[23] CEJA Opening Brief, at pp. 23-24; NRDC Opening Brief, at pp. 5-7.
[24] Decision, p. 35-36
[25] Ex. NRDC-1 (Martinez Opening Testimony), at p. 10
[26] Decision at p. 36
[27] *Ibid.* , at p. 11
[28] RT 2191-92 (Martinez, NRDC).

resource into account when it determined need.

The Decision similarly erred in failing to count the 157 MW of EE from new State and Federal Codes. First, while the calculation of EE based on new but already passed legislation was, unlike the "naturally occurring" calculation, based on a draft forecast, the Commission has not been hesitant to use such forecasts in the past.[29] The Commission cannot ignore its own past practice and evidence in the record regarding known efficiency codes and standards with an identifiable local impact. Second, regarding the claim that "there is nothing in the record to show how or whether any such updates might impact LCR needs," the 157 MW identified by CEJA and NRDC is adjusted for LCR impact.[30]

Finding of Fact 49 is not supported by substantial evidence and is arbitrary and capricious. Neither the Commission nor any party raised challenges to the cost effectiveness or reliability of either of the uncommitted EE resources at issue in this proceeding. In light of the clear evidence establishing these EE resources are "very likely" to be available to meet LCR, and the lack of any questions regarding the cost effectiveness and reliability of EE, the Decision's failure to count the full 733 MW of EE is incompatible with section 454.5(b)(9)(C), which requires that an electrical corporation "shall first meet its unmet resource needs through all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible." By dismissing 733 MW of EE, the Commission has adopted a position contrary to this requirement, as well as the State's Energy Action Plan and the Commission's own Loading Order. The Commission also has failed to ensure just and reasonable rates in violation of sections 451 and 454, As such, the Commission has failed to proceed as required by law in violation of section 1757(a)(2). Further, by discounting 733 MW of EE despite the uncontradicted evidence in the record establishing the availability of this preferred resource to reduce need, the Commission has made findings that are unsupported by substantial evidence in the record and abused its discretion in violation of section 1757(a)(4) and (5).

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[29] D.07-12-052 (2006 LTPP), the Commission approved the use of a draft demand forecast even though it had previously ordered the use of an older one in its Scoping Memo. See also D.13-02-015, at p. 49. ("We find that amounts of uncommitted energy efficiency in programs and standards already approved by this Commission and other agencies, but not yet in the demand forecast used by the ISO, should result in adjustments to demand forecasts for the purpose of authorizing LCR procurement levels.")

[30] CEJA Opening Brief, at p. 23; Ex. NRDC-1 (Martinez Opening Testimony), at p. 5, Table 1

D. The Decision Fails to Count At Least 770MW of Solar PV That Will Be Available to Meet LCR Need

The Decision makes the following findings of fact concerning the availability hundreds of MW of local solar resources:

> "Potential amounts of . . . solar PV resources also cannot be assumed to count toward meeting the LCR need on a megawatt-for-megawatt basis."[31]

> "Consistent with the revised Scoping Memo, the ISO correctly designates incremental customer-side solar PV as a 'second contingency' resource because it is difficult to predict the location where customer-side PV will get built."[32]

> "It is likely that Commission programs and the marketplace will increase the amount of solar PV in the future. However, there is no specific data or analysis in the record to determine where solar PV will locate, or the impacts of solar PV on LCR needs."[33]

These findings are not supported by substantial evidence in the record and are contrary to law.

1. Location of Solar PV in the LCR Area Does Not Affect LCR Benefit

The location of solar PV matters only to the extent that the solar PV is located either in the LA Basin or SDG&E territory. The Commission recognizes that all solar PV resources will be "on" at the LCR peak condition at the capacity factor of 0.45 or 0.46.[34] The Decision's use of these factors is already a substantial discount relative to the 0.55 capacity factor assumption specified in Track 2 of this proceeding.[35] There is no uncertainty about the output of solar PV at times of peak demand. Nonetheless, the decision ignores these solar resources on the grounds that it is not possible to identify in advance what will be the exact location(s) of solar PV within the LCR area.[36]

Statements in the Decision that the imprecise future location of solar PV within the LCR area is a basis for discounting its LCR value, and that the output at peak demand of this solar PV is uncertain, are unsupported by the record.[37] No record evidence exists in this proceeding upon

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[31] Decision, Finding of Fact 49, at p. 129.
[32] Decision, Finding of Fact 54, at p. 129.
[33] Decision, Finding of Fact 55, at p. 129.
[34] Revised Scoping Memo, Attachment A, p. 9.
[35] D.12-12-010, pdf p. 76. IV. Other Assumptions Common To All Scenarios, 0.55 = incremental small PV conversion factor for installed capacity to peak production MW (decimal).
[36] Decision, Finding of Fact 54, at p. 129.
[37] Decision, pp. 63-64.

which the Commission can support its determination that solar PV does not reduce LCR need. No factual support is provided in the Decision for ignoring the 278 MW of additional solar PV (by 2022) that the Commission admits will occur, simply because its location is not precisely known within the LCR area.

By failing to account for 278 MW of solar PV that the Decision admits is likely to be available by 2022, and by authorizing procurement based on an LCR determination inflated, in part, by this failure, the Commission has failed to prioritize solar energy over gas-powered procurement in violation of section 454.5(b)(9)(c), the State's Energy Action Plan, and the Commission's own Loading Order. The Commission also has failed to ensure just and reasonable rates in violation of sections 451 and 454. As such, the Commission has failed to proceed in the manner required by law in violation of section 1757(a)(2). Further, by ignoring record evidence of the likely availability of 278 MW of solar PV based on the irrelevant fact that it is unknown precisely where in the LCR area these resources will be located, the Decision has failed to support its findings with substantial evidence in violation of section 1757(a)(4) and abused its discretion in violation of section 1757(a)(5).

2. AB 327, Codified as Public Utilities Code Section 2827, Has Greatly Increased the Amount of Solar PV that Will Be Added By 2018 but the Decision Improperly Ignores This Additional Solar Resource.

The Commission assumes that California's investor-owned utilities (IOUs) are in the process of meeting the California Solar Initiative (CSI) solar PV targets.[38] The IOUs are to have 1,940 MW online by December 2016.[39] This solar capacity is installed on the customer side of the electric meter, on rooftops and parking lots primarily, and is known as "net-metered" solar.

The IOUs' net-metered solar targets increased dramatically with AB 327[40] in October 2013, which enacted Public Utilities Code Section 2827(c)(4)(B) and, established minimum statutory net-metering rooftop solar targets to be met by the IOUs by mid-2017. AB 327 established a statutory mandate to add up to 5,256 MW of solar energy resources in California.

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[38] Revised Scoping Memo, Attachment A, p. 8.

[39] Decision 06-12-033, *Opinion Modifying Decision 06-01-024 and Decision 06-08-028 In Response to Senate Bill 1*, December 14, 2006, p. 36. Finding of Fact 15: The Commission's ("The Commission" is equivalent to "the IOUs" in this context) 65% share of the 3,000 MW statewide goal is 1,940 MW, and 1,750 MW for the mainstream solar incentive program.

[40] Assembly Bill No. 327 (Cal. 2013)

This is a 3,316 MW increase over the 1,940 MW target established for the IOUs by the Commission in D.06-12-033. The IOUs are required by Section 2827(c)(4)(C) to report on a monthly basis their progress in meeting the new minimum solar PV targets by mid-2017. Therefore, at a minimum, the IOUs by law will add 3,316 MW of additional net-metered solar by mid-2017.

In this proceeding, the Commission assumed that only 1,011 MW of additional solar PV would be added by 2018 and 1,300 MW by 2022 in the entire CAISO control area, which includes PG&E, SCE and SDG&E.[41] The Commission's 2018 additional solar PV assumption is only one-third of the additional solar PV that is required by section 2827(c)(4)(B), and therefore only one-third of the solar capacity that is very likely or certain to be added by mid-2017. The Commission's 2022 assumption is only about 40 percent of the solar PV that is required by statute and thus is very likely or certain to be added by mid-2017.

At a minimum, as a result of current statutory requirements, 2,305 MW of additional solar PV capacity will be added by California's IOUs by mid-2017 beyond the 1,011 MW that the Commission counts as available.[42] Of this 2,305 MW of additional solar PV capacity, 866 MW will be located in SCE's LA Basin and 221 MW will be located in SDG&E territory.[43] Of this amount, about 492 MW will be available on peak to meet LCR need in addition to the 278 MW of peak solar PV in 2022 assumed in the Decision.[44] All of this required 770 MW of peak solar PV capacity, that will be meeting LCR need, is ignored by the Decision.

Findings of Fact 49, 54, and 55 are not supported by substantial evidence and are arbitrary and capricious. By ignoring all additional solar PV capacity when assessing LCR need, the Decision has failed to proceed as required by Section 454.5(b)(9)(C), mandating that utilities must first meet their "unmet resource needs through all available energy efficiency and demand reduction resources that are cost-effective, reliable and feasible." Solar PV is a renewable energy resource that reduces demand at the source, consistent with Section 454.5(b)(9)(C).

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[41] *Ibid.*, Attachment A, p. 9.

[42] 3,316 MW – 1,011 MW = 2,305 MW.

[43] Revised Scoping Memo, Attachment A, p. 9. Fraction of additionalsolar PV in LA Basin in 2018 compared to ISO as a whole = 380 MW/1011 MW = 0.376. Fraction of additionalsolar PV in SDG&E territory in 2018 compared to ISO as a whole = 97 MW/1011 MW = 0.096.

[44] The Decision assumes the solar capacity factors at peak demand in the LA Basin and SDG&E territory are 0.45 and 0.46, respectively. Therefore, total additional solar PV available at peak is: (866 MW x 0.45) + (221 MW x 0.46) = 492 MW. This is additional solar PV beyond the 278 MW of peak solar PV in 2022 assumed in the Decision.

The Decision has also failed to proceed as required by Section 2827(c)(4)(B), which establishes explicit capacity targets for solar PV in IOU service territories. The solar PV targets are established by state law. The Commission cannot presume that the law will not be followed and that the solar PV resource will play no role in reducing LCR need. The Decision erroneously relies on such an assumption in contravention of the intent of AB 327 and the Commission failed to proceed as required by Section 2827(c)(4)(B).

In addition, by failing to account for the solar PV contribution to reducing LCR need, the Commission has authorized duplicative procurement to address a need that will already be met by solar PV resources, thereby failing to ensure just and reasonable rates in violation of sections 451 and 454. As such, the Commission has failed to proceed as required by law in contravention of section 1757(a)(2). Likewise, the Commission has failed to support its findings with substantial evidence and abused its discretion in violation of section 1757(a)(4) and.(5).

E. The Decision Fails to Count 745 MW of Highly Likely Energy Storage Resources as Required by AB 2514

The Decision makes the following finding of fact concerning the availability of energy storage resources:

> "The energy storage targets adopted in D.13-10-040 cannot be assumed to count toward meeting the LCR need on a megawatt-for-megawatt basis."[45]

This finding is not supported by substantial evidence in the record and is contrary to law.

AB 2514, as codified at Pub. Util. Code Section 2835 et. seq., mandates that utilities comply with energy storage targets adopted by the Commission.[46] The Commission set mandatory energy storage targets for the utilities in Decision D.13-10-040. Decision D.13-10-040 requires that utilities purchase energy storage projects equal to 1 percent of their 2020 annual peak load by 2020,[47] for a total of 1,325 MW across all utilities installed and operational by no later than the end of 2024.[48] Decision D. 13-10-040 orders SDG&E to purchase 165 MW of energy storage by 2020, and orders SCE to purchase 580 MW of energy storage by 2020, a total of 745 MW.[49]

[45] Decision, Finding of Fact 49, at p. 129.
[46] Pub. Util. Code Sections 2836(a) and 2837
[47] D.13-10-040, Conclusion of Law 29, at p. 74
[48] D.13-10-040, Conclusion of Law 41, at p. 76
[49] D.13-10-040, Ordering Paragraph 1, at p. 76; Appendix A at p. 2.

The Decision in the instant proceeding fails to count 745 MW of energy storage resources that will be added in SCE and SDG&E territories pursuant to AB 2514 and Decision D.13-10-040. The Decision justifies this failure by claiming that these resources are too "uncertain" to count towards LCR. By failing to count these energy storage resources, the Decision ignores the fact that under Pub. Util. Code Section 2835 et. seq. the energy storage targets adopted by the Commission are *mandatory*.[50]

Public Utilities Code Section 2836(a)(1) directs the Commission to "determine appropriate targets, if any, for each load-serving entity to procure viable and cost-effective energy storage systems to be achieved by December 31, 2015, and December 31, 2020." Section 2836(a)(2) mandates that the Commission adopt procurement targets, if determined to be appropriate, by October 1, 2013.

AB 2514 further provides that, once adopted by the Commission, energy storage targets are mandatory and *must* be met by the utilities. Public Utilities Code Section 2837 provides that once energy storage targets are adopted, "[e]ach electrical corporation's renewable energy procurement plan [as required by Public Utilities Code Section 399.11 et. seq.] shall require the utility to procure new energy storage systems that are appropriate to allow the electrical corporation to comply with the energy storage system procurement targets and policies adopted pursuant to Section 2836." The purposes of this mandatory utility energy storage procurement include:[51]

- Reducing the need for new fossil-fuel powered peaking generation;
- Reducing purchases of electricity generation sources with higher emissions of greenhouse gasses;
- Reducing the demand for electricity during peak periods;
- Avoiding or delaying investments in transmission system upgrades;
- And using energy storage systems to provide the ancillary services otherwise provided by fossil-fuel generating facilities.

By ignoring 745 MW of energy storage resources required by law to be available, the Decision subverts each of these purposes.

[50] D.13-10-040, Conclusion of Law 41, p. 76. It is reasonable to require the utilities to contract for their storage targets by no later than 2020, with installation and ope ration of a total of 1,325 MW across all utilities installed and operational by no later than the end of 2024.
[51] Pub. Util. Code § 2837.

Further, the Commission errs in justifying its failure to account for the energy storage targets by claiming that energy storage is "uncertain."[52] Under AB 2514, the location and effectiveness of energy storage resources are in no way "uncertain." The Commission's authority extends to both the placement of energy storage facilities built by utilities, and the selection of third party energy storage facilities. The statutory mandates are clear. Thus, the Commission must exercise its authority to ensure that energy storage resources are certain.

In meeting the mandatory energy storage requirements adopted by the Commission in D.13-10-040, utilities must comply with Section 2836, which provides that the purposes of energy storage procurement include reducing the need for fossil-fuel powered peaking generation, reducing the need to purchase electricity generation sources with higher greenhouse gas emissions, and using energy storage to provide the ancillary services normally provided by fossil fuel generation.

In order to satisfy these purposes, the Commission and the Utilities must site and select projects that maximize contributions to meeting LCR. Energy storage that does not contribute to local capacity would need to be backed up by redundant locally sited generation, and as such would not meet the clear purposes stated in section 2836.

Finding of Fact 49 is not supported by substantial evidence and is arbitrary and capricious. By failing to count this mandatory 745 MW of energy storage, and by authorizing procurement based on an LCR determination driven, in part, by this failure, the Commission has adopted a position directly contradictory to the requirements of AB 2514 and sections 2835, et seq., and has failed to ensure just and reasonable rates in violation of sections 451 and 454. The Commission thus has failed to proceed as required by law in violation of section 1757(a)(2). Further, by discounting energy storage despite the clear requirements of AB 2514, sections 3835 et seq., and the uncontradicted record evidence of the availability of 745 MW of this resource, the Commission has failed to base its decision on findings supported by substantial evidence and abused its discretion in violation of section 1757(a)(4) and (5)

F. The Discounting of Preferred Resources and Emphasis on Gas-Fired Generation Is Counter to Law and Commission Policy

The Decision approves levels of natural gas-fired procurement that are far higher than current evidence shows is necessary as documented in the CAISO *2014 Summer Loads &*

[52] Decision at, p. 61.

Resources Assessment.[53] The Decision authorizes 60 to 79 percent of the SCE procurement range of 1,900 to 2,500 MW to be natural-gas fired, depending on how much of this approved procurement range SCE chooses to construct.[54] The Decision authorizes 60 to 75 percent of the SDG&E approved procurement range of 500 MW to 800 MW to be natural-gas fired generation.[55]

The Decision acknowledges that significant electric power supplies have come online in recent years.[56] The Commission requires the utilities to maintain a planning reserve margin of 15 percent.[57] The planning reserve margin projected by CAISO for the combined peak load of SCE and SDG&E in the summer of 2014 is 35.9 percent. A contributing factor to the high reserve margin is the fact that there has been no net increase in peak load in either SCE or SDG&E service territories over the last eight summers (2006 – 2013).[58]

In the twelve months from SONG's permanent shutdown in June 2013 until the end of May 2014, 3,328 MW of total new capacity has been added in SCE and SDG&E territories.[59] Of this total, 2,257 MW counts as reliable capacity available at peak demand.[60] SONGS had a reliable capacity of 2,246 MW.[61] Thus, the capacity lost by the SONGS closure has already been addressed with new capacity. There is no evidentiary basis for permitting additional procurement based on the closure of SONGS.

[53] CAISO, *2014 Summer Loads and Resources Assessment*, May 9, 2014, p. 13 (attached to Exhibit 1, Declaration of David Peffer in Support of POC's Application for Rehearing).
[54] The Decision (p. 141) directs SCE to procure at least 1,000 MW, but no more than 1,500 MW, of this SCE local capacity from conventional gas-fired resources. Assuming SCE opts for the higher 1,500 MW conventional gas-fired procurement limit, the gas-fired percentage of total SCE procurement authorized in the Final Decision ranges from 60 percent [(1,500 MW ÷ 2,500 MW) x 100] to 79 percent [(1,500 MW ÷ 1,900 MW) x 100].
[55] The Decision (p. 143) directs SDG&E to procure at least 500 MW to 800 MW of new localcapacity, of which at least 200 MW must be from resources other than conventional gas -fired generation. Therefore, the gas-fired percentage of total SDG&E procurement authorized in the Decision ranges from 60 percent [(300 MW ÷ 500 MW) x 100] to 75 percent [(600 MW ÷ 800 MW) x 100].
[56] Decision, p. 23.
[57] CAISO, *2014 Summer Loads and Resources Assessment*, May 9, 2014, p. 4 (attached to Exhibit 1, Declaration of David Peffer in Support of POC's Application for Rehearing).
[58] Opening Comments of Sierra Club California On ALJ Gamson's Questions from the September 4, 2013 Prehearing Conference, Figures 1 and 2, pp. 12-13.
[59] CAISO, *2014 Summer Loads and Resources Assessment*, May 9, 2014, p. 13 (attached to Exhibit 1, Declaration of David Peffer in Support of POC's Application for Rehearing).
[60] Only a portion of total solar and wind capacity is assumed to be available to meet peak demand. The solar capacity factor assumed by CAISO in the *2014 Summer Loads and Resources Assessment* is 0.68 (Table 5, p. 14). The wind capacity factor assumed by CAISO at peak is 0.19. This is the reason for the difference between installed capacity and capacity available at peak demand.
[61] *Ibid.*, p. 9.

Much of the new capacity contributing to the current high planning reserve margin is renewable energy.[62] About 2,752 MW of the 3,328 MW of new SCE and SDG&E capacity is renewable energy, primarily solar energy.[63] The remaining 576 MW is natural gas-fired generation. As a result, natural gas-fired generation is only 17 percent of total SCE and SDG&E generation capacity that came online in the past year. Natural gas-fired generation is about 25 percent of the 2,257 MW of this new capacity that is available at times of peak demand. The current procurement pattern of SCE and SDG&E is much more consistent than the Decision with D.07-12-052 at 12, where the Commission stated:[64]

> Once demand response and energy efficiency targets are reached, "the utility is to procure renewable generation to the fullest extent possible." The obligation to procure resources according to the Loading Order is ongoing.

More than 75 percent of the new supply capacity purchased by SCE and SDG&E in 2013-2014 is renewable energy. As a result of the Decision, this procurement trend will reverse in the future, with up to 75 percent or more of the new supply being natural gas-fired generation. This is contrary to California law, including but not only section 454.5(b)(9)(c), the State's Energy Action Plan, and the Commission's Loading Order, which mandate prioritizing non-gas-fired energy sources. Accordingly, the Commission has failed to proceed as required by law, in violation of section 1757(a) (2). Because the Decision is at odds with current trends minimizing gas-fired generation in California, the Decision also is not supported by substantial evidence and constitutes an abuse of the Commission's discretion under sections 1757(a)(4) and (5).

III. IN DETERMINING NEED, THE DECISION IMPROPERLY FAILS TO COUNT VERY LIKELY NON-GAS FIRED GENERATION GRID SUPPORT PROJECTS AND CONTINUED OPERATION OF EXISTING GAS-FIRED GENERATION

A. 550 MVAR of New Static VAR Compensators at San Onofre Is Very Likely to Be Available

[62] CAISO, *Summer Loads and Resources Assessment*, May 9, 2014, Table 1, p. 6. Total SP26 (SCE + SDG&E) summer 2014 supplies = 36,699 MW. CAISO forecast summer 2014 1-in-2 SP26 peak demand = 26,994 MW. Supply need to maintain 17 percent reserve margin = 26,994 MW × 1.17 = 31,583 MW. Summer 2014 supplies available to SCE and SDG&E beyond Commission 15 – 17 percent planning reserve margin requirement = 36,699 MW – 31,583 MW = 5,116 MW.
[63] *Ibid.*, p. 13. Natural gas-fired generation added between June 1, 2013 and May 31, 2014 in Southern California includes the El Segundo combined cycle plant in SCE territory (526.7 MW) and the Escondido combustion turbine in SDG&E territory (49.5 MW).
[64] Decision, p. 23.

SCE has proposed adding another 550 MVAR of Static VAR Compensators at San Onofre.[65] CAISO modeled a 550 MVAR Static Compensator at San Onofre in connection with the 2012-13 Transmission Plan and determined that it would reduce LCR need in the LA Basin by 300 MW.[66] Despite this evidence, the Decision finds, in Finding of Fact 20, that the record lacks sufficient evidence to determine the LCR impact of additional reactive power resources. The evidence directly contradicts this finding. Finding of Fact 20 is inconsistent with SCE's stated intent to install 550 MVAR at San Onofre. At a minimum, the evidence supports a reduction in LCR need of at least 300 MW, as CAISO determined. By failing to account for this 300 MW of capacity very likely to be available based on SCE's plans, the Decision permits unnecessary and duplicative procurement, in contravention of sections 451 and 454, requiring that rates be just and reasonable. As such, the Commission has not proceeded in the manner required by law, in violation of section 1757(a)(2). For the same reason, the Decision is not based on findings supported by substantial evidence and thus constitutes an abuse of the Commission's discretion under sections 1757(a)(4) and (5).

B. Huntington Beach 280 MVAR Synchronous Condensers Already Exist and Must Be Counted.

The Decision fails to count the 280 MVAR Huntington Beach synchronous condensers, despite the fact that these resources are already in place and operational, and are currently providing 280 MVAR of reactive power at a key location, thereby reducing LCR need. CAISO's 2012-2013 Transmission Plan states: "The ISO assumed that the Huntington Beach synchronous condensers will be available for the intermediate (i.e., 2018) time frame and will assume their continued use or equivalent support. This was identified as part of the need for the SONGS absence scenario for summer 2013."[67] CAISO repeated this position in its July 15, 2013 Workshop on SONGS mitigation efforts.[68] Yet CAISO failed to model the Huntington Beach synchronous condensers for 2022 based on the speculative assumption that repowering would

[65] Decision, p. 33: "SCE has proposed adding another 550 MVAR [Static VAR Compensators] at San Onofre. CEJA shows that the ISO estimates that this addition will reduce need in the LA Basin by 300 MW. This reactive support was not included in the 2022 results of the ISO's Track 4 Opening Testimony."

[66] Ex. CEJA-2 (May Supporting Documents), at p. 56.

[67] Exhibit CEJA 2, at p. 26.

[68] Exhibit CEJA 2, at p. 39-40.

occur on that site.[69] The Decision admits that these resources are in place, yet declines to count them on the grounds that "while the Huntington Beach condensers are assumed by the ISO to be available in the 2018 SONGS-out assessment, they are not included in the revised Scoping Memo's Track 4 2022 assumptions."[70] In so doing, the Decision violates section 1705, which requires the Commission to consider "all issues material to the order or decision." In this regard, every issue that must be resolved to reach a Decision's ultimate finding is "material."[71] The Commission is required to "consider sua sponte every element of public interest affected by . . . [utility proposals] which it is called upon to approve," even if not prompted by a party, and the Commission's failure to do so is a ground for its decision's annulment.[72]

The failure to include the impact of the existing Huntington Beach synchronous condensers on LCR need is contradicted by the evidence in the record. These units exist now and will either continue to operate or "equivalent support" will replace them. By failing to account for this 280 MVAR of reactive power, the Decision permits unnecessary and duplicative procurement, in contravention of sections 451 and 454, requiring that rates be just and reasonable. As such, the Commission has not proceeded in the manner required by law, in violation of section 1757(a)(2). For the same reason, the Decision is not based on findings supported by substantial evidence and thus constitutes an abuse of the Commission's discretion under sections 1757(a)(4) and (5).

C. The Decision Fails to Even Acknowledge the Imperial Valley Flow Controller Project Which Will Reduce LCR Need by 500 MW In SDG&E Territory

SDG&E has submitted a proposal to CAISO to install a flow control device, referred to as the Imperial Valley flow controller.[73] The purpose of this flow controller is to prevent the tripping of a special protection scheme on the Comisión Federal de Electricidad (CFE) line, a scheme that was triggered by the N-1-1 contingency modeled by CAISO. SDG&E witness Jontry testified that the proposal was submitted with a requested in-service date in either 2015 or

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[69] Decision, p. 32: "The Huntington Beach synchronous condensers are also completed. However, while the Huntington Beach condensers are assumed by the ISO to be available in the 2018 SONGS-out assessment, they are not included in the revised Scoping Memo's Track 4 2022 assumptions."
[70] CEJA Opening Comments, p. 9.
[71] *Pacific Tel. & Tel. Co. v. Public Utilities Commission* (1965) 62 Cal.2d 634, 648
[72] *City of Los Angeles v. Public Utilities Com.* (1975) 15 Cal.3d 680, 694; quoting *Northern California Power Agency v. Public Util. Com.* (1971) 5 Cal.3d 370, 380
[73] CEJA Opening Comments, p. 6.

2017.[74] No party submitted testimony or evidence that this flow controller will not be in place by 2017. CEJA testified that the resulting reduction of LCR need in the San Diego region would be at least 500 MW.[75] This testimony was not contradicted. This project is not mentioned in the Decision. This project is very likely to occur. There is no evidence in the record to contradict this. The project addresses a major aspect of the contingency modeled by CAISO in this proceeding and eliminates the need for 500 MW of new resources in SDG&E territory. As a result, SDG&E's procurement authorization should be reduced by 500 MW.

By failing to address the Imperial Valley flow controller project, the Decision violates section 1705, requiring that the Commission make findings of fact and conclusions of law on every material issue, as well as the Commission's duty to "consider sua sponte every element of public interest affected by . . . (utility proposals) which it is called upon to approve."[76] By not reaching any findings regarding this key issue the Commission has failed to support its Decision with findings in violation of Section 1757(a)(3), failed to assure just and reasonable rates in violation of Sections 451 and 454, failed to proceed in the manner required by law in violation of Section 1757(a)(2), and abused its discretion in violation of Section 1757(a)(5).

D. The Decision's Presumption of Complete Early Retirement of OTC Power Plants Is Unsupported by the Record

Historically coastal California power plants have used seawater in once-through cooling (OTC) to meet cooling requirements. California regulations require these plants to either substantially reduce seawater usage in coming years by at least 93 percent through process modifications or reduced operation, or retire.[77] As the only large base-load power plant on the Southern California coast, SONGS was responsible for about 90 percent of Southern California OTC power plant seawater withdrawals when it was operational.[78]In effect, SONGS met its

[74] RT at 1750 (SDG&E, Jontry).
[75] Ex. CEJA-1 (May Opening Testimony), at p. 31.
[76] *City of Los Angeles v. Public Utilities Com.* (1975) 15 Cal.3d 680, 694; quoting *Northern California Power Agency v. Public Util. Com.* (1971) 5 Cal.3d 370, 380
[77] State Water Resources Control Board Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling, as amended June 18, 2013, p. 4. See: http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/policy.shtml .
[78] Prepared Opening Testimony of Bill Powers on Behalf of Sierra Club California, September 30, 2013, p. 22.

December 2022 OTC compliance date[79] almost ten years in advance when it permanently shut down in June 2013.[80]

The early retirement of SONGS has almost completely met the state's OTC phase-out objectives in Southern California a decade ahead of schedule. However, the Decision presumes as a certainty that all remaining OTC plants, which provide cost-competitive reserve capacity to assure grid reliability in Southern California, will retire over the next several years and create a need for new power supplies in the LA Basin and SDG&E territory that otherwise would not exist.

The 2018 need identified in the Decision is created by assuming the retirement of once-through cooling ("OTC") power plants and non-OTC power plants such as the 640 MW Etiwanda plant in SCE territory and the 188 MW Cabrillo II combustion turbines in SDG&E territory.[81] The Decision is clear on this point:

> Such long-term LCRs are expected to result from the retirement of approximately 5,900 Megawatts (MW) from current once-through cooling generators in the Los Angeles (LA) Basin, and approximately 900 MW in the San Diego local area, to comply with State Water Quality Control Board regulations. [82]

If these retirements do not occur by 2018, the need identified in the Decision will not materialize. The refusal of the utilities to allow OTC power plant owners to recover the cost of coming into compliance with the OTC regulation in their power supply bids is the reason these OTC plants may retire by 2018.[83] One readily-available alternative to the Commission is to postpone OTC retirements, such as Encina in SDG&E territory, and non-OTC retirements such as Cabrillo II, for a limited time to bridge any projected gap until sufficient preferred resources are added to the system.[84] The Commission failed to consider this material issue that would result in less need and thus less cost for the ratepayers.

The State Water Resources Control Board's OTC policy does not require retirement of the OTC plants in SCE and SDG&E territories. Rather, it merely requires that OTC plants either

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[79] *Ibid.*, p. 22.
[80] *Ibid.*, p. 22.
[81] Opening Comments of Sierra Club California on ALJ Gamson's Questions from the September 4, 2013 Prehearing Conference, R.12-03-014, September 30, 3013, Figure 2, pp. 11-12.
[82] Decision, p. 6.
[83] POC Opening Testimony, pp. 18-21.
[84] Opening Comments of Sierra Club California On ALJ Gamson's Questions from the September 4, 2013 Prehearing Conference, Figures 1 and 2, p. 12, p. 12.

reduce intake flow and velocity (Track 1 compliance) or reduce impacts to aquatic life comparably by other means (Track 2 compliance).[85]

However, the OTC plants must be able to recover the costs they incur to comply with the OTC policy in the competitive bids these plants submit to utilities. For example, the owner of 964 MW Encina Power Plant in SDG&E territory (Cabrillo, owned by NRG), has stated that it has compliance plans in place for Encina Units 4 and 5, and that the only barrier to implementing these plans is the lack of an adequate Power Purchase Agreement.[86]

SDG&E and CAISO have admitted that their goal is to push for the retirement of Encina. CAISO describes the objectives of its Track 4 study as including: "minimizing the OTC generation repowering or replacement need."[87] Similarly, in A.11-05-023, SDG&E submitted testimony stating that the PPTA's proposed in that proceeding "will help to… facilitate the retirement of aging and Once Through Cooling ("OTC") generation resources."[88] It may be that Encina generation is significantly more cost-effective than other existing and proposed resources. It is unreasonable and unlawful for the Commission to allow any generation procurement based on projections that assume the retirement of potentially competitive generation that has been effectively forced into retirement.

Using the test of likelihood introduced for the first time by the Commission in Track 4 to determine whether to count a resource toward the LCR, "very likely" or "reasonably possible," the record does not support a factual determination that all OTC plants will retire en mass by their respective compliance dates. There are no findings in that record that support the assumption in the Decision that all OTC plants will retire by their compliance dates, a violation of section 1757(a)(4). As a result the Commission has approved over-procurement, failed to assure just and reasonable rates, in violation of sections 451 and 454, failed to proceed as required by law, in violation of section 1757(a)(2), and abused its discretion in violation of section 1757(a)(5).

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[85] State Water Resources Control Board Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling, as amended June 18, 2013, p. 4.
[86] POC Opening Testimony, Exhibit 15.
[87] CAISO Opening Testimony, p. 17
[88] POC Opening Testimony, Exhibit 19.

IV. IN ALLOWING THE USE OF N-1-1 AS THE CRITICAL CONTINGENCY, THE COMMISSION HAS FAILED TO PROCEED AS REQUIRED BY LAW 렙□η

A. In Allowing N-1-1 the Decision Failed to Consider a Material Issue of Public Interest on the Merits

The need determination reached in D.14-03-004 is based on the results of CAISO's modeling.[89] The results of CAISO's modeling, in turn, were driven in significant part by the decision to use the Sunrise Powerlink/Southwest Powerlink (Sunrise/SWPL) N-1-1 event as the limiting critical contingency for the San Diego local area. "N-1-1" means the sequential loss of these two transmission lines with time for system readjustment (generally assumed to be up to 30 minutes) between the first and second outage.[90] In the instant proceeding, several parties, including POC, submitted evidence and presented arguments challenging the use of the Sunrise Powerlink/SWPL N-1-1 event as the limiting critical contingency for the San Diego local area.

The Decision dismisses these challenges to N-1-1 on three grounds: (1) changing the limiting critical contingency used in CAISO's modeling would directly change the CAISO modeling input; (2) the determination of whether N-1-1 is a Western Electricity Coordinating Council ("WECC")[91] Category C contingency, for which contingency planning is required, or a WECC Category D contingency, for which no needs assessment is necessary, is more within the expertise of CAISO than the Commission; and (3) CAISO has referenced a probability range for the N-1-1 event that indicates it is a credible contingency that must be mitigated.[92] Each of these grounds is legally erroneous, not supported by the Commission's findings or the evidentiary record, and, thus, an abuse of the Commission's discretion.

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[89] D.14-03-004 at p. 28

[90] Sierra Club Reply Testimony, Exhibit 1, p. 7.

[91] WECC is a regional entity of the North American Electric Reliability Corporation ("NERC"). Pursuant to 16, U.S.C. Section 824o, the Federal Energy Regulatory Commission has named NERC as the entity responsible for developing mandatory and enforceable electricity reliability standards.

[92] Decision, Findings of Fact 24, 31, and 32, p. 126.

1. *By rejecting challenges to N-1-1 as impermissible challenges to modeling inputs, the Commission has failed to proceed as required by law, violated the parties due process rights, and abused its discretion.*

The Decision rejects the challenges to the use of N-1-1 as the limiting critical contingency for the San Diego area, in part, on the claim that such challenges to the modeling inputs adopted in the Scoping Memo are impermissible, and that only the output results of the model can be adjusted up or down based on differences between the Commission's assumptions on the quantity of available resources to meet the LCR need and the resource assumptions used by CAISO when it ran the model.[93] The Decision treats the CAISO decision to use the Sunrise/SWPL N-1-1 as the critical contingency as inviolate based on CAISO's presumed greater level of expertise in identifying the critical contingency.[94] By treating the modeling assumptions as unchallengeable, and as such rejecting the challenges to N-1-1 on the grounds that doing so would change the model input, the Commission has failed to proceed as required by law, violated the parties' due process rights, and abused its discretion.

Section 1705 requires the Commission to consider "all issues material to the order or decision." Every issue that must be resolved to reach a Decision's ultimate finding is "material."[95] The Commission has a proactive duty to identify and fully adjudicate issues of public interest. Failure to fulfill this duty is grounds for a Decision's annulment:

> [t]he Commission may and should consider sua sponte every element of public interest affected by . . . [utility proposals] which it is called upon to approve. It should not be necessary for any private party to rouse the Commission to perform its duty. . . Thus, we conclude that the Commission failed to give adequate consideration to the . . . issues . . . and that its decision must be annulled.[96]

By treating modeling assumptions adopted in the Scoping Memo as unchallengeable, and by dismissing challenges to these assumptions raised by the parties, the Commission has failed to adjudicate, consider, and resolve the reasonableness of these assumptions as required by these provisions. Furthermore, the Commission has denied parties the opportunity for a full and fair

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[93] Decision at p. 49; Decision, Finding of Fact 30, p. 126.
[94] Decision, Finding of Fact 32, p. 126.
[95] *Pacific Tel. & Tel. Co. v. Public Utilities Commission* (1965) 62 Cal.2d 634, 648
[96] *City of Los Angeles v. Public Utilities Com.* (1975) 15 Cal.3d 680, 694; quoting *Northern California Power Agency v. Public Util. Com.* (1971) 5 Cal.3d 370, 380

hearing on these issues and as such has violated the parties' due process rights. This further constitutes a failure by the Commission to proceed in the manner required by law and an abuse of the Commission's discretion under sections 1757(a)(2) and (a)(5)

2. *The Decision's use of N-1-1 is not supported by substantial evidence in light of the whole record*

NERC standards require modeling of a range of contingencies, from (Category A) to extreme events (Category D).[97] The two intermediate categories of contingencies, Category B, events resulting in the loss of a single element and Category C, event(s) resulting in the loss of two or more elements constitute the majority of contingencies examined in SCE's studies. An example of a Category B contingency is the fault and loss of one transformer bank. An example of a Category C contingency is the fault and simultaneous loss of two transmission lines that share a common tower, [98] or the sequential loss of two transmission lines within 30 minutes of each other. Category D contingencies are extreme events with no specific performance requirements other than an evaluation for risks and consequences. If the Sunrise/SWPL N-1-1 contingency is a Category D contingency, NERC reliability standards do not require mitigation.[99]

The Decision bases its use of N-1-1, in significant part, on the finding that "[t]here is no credible basis upon which to find that the ISO's analysis, that the limiting contingency for the SONGS study area is the N-1-1 Category C SWPL/Sunrise overlapping outage assumed and modeled by the ISO, is flawed."[100] This finding is based on the Decision's failure to consider key evidence and as such is in error.

CAISO and other parties contended that the Sunrise/SWPL N-1-1 was a WECC Category C contingency. They further contended that because the Sunrise/SWPL N-1-1 was the most severe Category C contingency for the San Diego local area, they were required to use it as the limiting critical contingency for the area in order to comply with mandatory WECC planning guidelines regardless of the probability, consequence and cost associated with the Sunrise/SWPL N-1-1.[101]

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[97] SCE Opening Testimony, p. 21.
[98] *Ibid*, p. 21.
[99] SCE Reply Testimony, p. 17.
[100] Finding of Fact 33 at p. 127
[101] Jontry Reply Testimony, p. 3.

In response, several parties, including POC, argued that WECC has an official process in place that would allow SDG&E to have the Sunrise/SWPL N-1-1 re-categorized from a Category C contingency, which must be planned for and mitigated, to a Category D contingency, which is considered so unlikely to occur that utilities are not required to plan for it. The evidence regarding the applicability of this process, known as the Probabilistic Based Criteria Review ("PBRC") process, is discussed briefly in the Decision:

> On cross examination, witness Powers claimed the overlapping outage of SWPL and Sunrise is a "functional" Category D because SDG&E could "convert it from a Category C to a Category D" using the WECC process followed by SDG&E in evaluating the performance criteria of the Sunrise route alternatives. However, SDG&E witness Jontry testified that the WECC re-classification process is not available for an N-1-1 contingency. ISO witness Sparks also noted that he had never seen the process applied to a Category C3 contingency, and that WECC is moving to eliminating the process altogether.[102]

In cross examination, both SDG&E witness Jontry and CAISO witness Sparks admitted that the PBRC process exists, and that the process allows for probabilistic exceptions to NERC categorizations.[103,104]

In describing CAISO witness Sparks testimony, the Decision selectively omits the fact that Sparks conceded that the Sunrise/SWPN N-1-1 qualifies for the PBRC process:

> THE WITNESS [Mr. Sparks]: As I described, it [the PBRC process] applies to – I've seen it in examples applied to single contingencies being reclassified as Category C and sometimes it can reclassify double contingency to Category B. I've never seen it [the PBRC process] applied to Category C3, but I suppose it could be.[105]

In relying on Sparks' claim that "WECC is moving to eliminating the process altogether" the Decision ignores the fact that, when questioned, Sparks was unable to substantiate this claim with any specific information beyond the vague claim that "the general population of WECC is moving to eliminate this process."[106]

[102] Decision, p. 47.
[103] Tr. Vol.12, p. 1772, lines 23-28.
[104] Tr. Vol.11, p. 1560, lines 1-19.
[105] Tr. Vol. 11, p. 1562, lines 15-21.
[106] Tr. Vol. 11, p. 1563, lines 8-10

When POC asked whether there was a specific proposal or proceeding at WECC to eliminate the PBRC process, CAISO objected based on relevance, and ALJ Gamson instructed POC's counsel to continue down a different line of questioning.[107]

In relying on SDG&E witness Jontry's claim that the PBRC process does not apply to the Sunrise/SWPL N-1-1, the Decision adopts a highly contradictory position. One of the key findings that the Decision uses to justify the use of N-1-1 is that ISO has a special "expertise" in "issues regarding whether an ISO-determined Category C contingency should be functionally a Category D contingency under WECC reliability standards."[108] Given this special expertise, the testimony of CAISO's transmission expert admitting that the N-1-1 contingency qualifies for the PBRC process should trump SDG&E's testimony claiming otherwise.

In any event, the Commission's failure to consider the availability of the WECC PBRC process to eliminate the Sunrise/SWPL N-1-1 as a viable contingency, amounts to a violation of section 1705, which requires the Commission to consider all material issues, particularly those impacting the public interests. Because it results in unnecessary procurement, the Decision also violates the Commission's duty under sections 451 and 454 to ensure just and reasonable rates. As such, the Decision also constitutes a failure of the Commission to proceed in the manner required by law under section 1757(a)(2). Further, because the Decision selectively ignores key evidence, the Decision's acceptance of N-1-1 as the limiting critical contingency for the San Diego area is not supported by substantial evidence in light of the entire record as required under section 1757(a)(4) and amounts to an abuse of the Commission's discretion under section 1757(a)(5).

3. *The Decision relies on CAISO's erroneous interpretation of the probability of a Sunrise Powerlink/SWPL N-1-1 to assert the N-1-1 is a credible event*

The Decision's failure to independently evaluate the probability of Sunrise/SWPL N-1-1 contingency exposes ratepayers to billions in unnecessary infrastructure costs to address a LCR need created in substantial part by application of the Sunrise/SWPL N-1-1 contingency. The Decision's Finding of Fact 24 references probabilities of occurrence for this N-1-1 event that were used by SDG&E to establish the simultaneous loss of Sunrise/SWPL (N-2) as a very low

[107] Tr. Vol 11, p. 1563, line 15 through p. 1564, line 22
[108] Finding of Fact 32 at p. 126

probability Category D event that does not require mitigation. As a result, the Decision is using probability data that would identify the Sunrise/SWPL N-1-1 contingency as a probabilistic Category D event that does not require mitigation. This contravenes its own Finding of Fact 24.

SDG&E witness Jontry insisted that all N-1-1 events must be mitigated regardless of probability, consequence and cost.[109] However, CAISO witness Sparks proffered a probability range for the Sunrise/SWPL N-1-1, referencing the 21 years to 928 years probability of occurrence from the December 2007 SDG&E probabilistic study that was used by SDG&E to reclassify the original Sunrise/SWPL route N-2 from Category C to Category D.[110] The 21 years to 928 years probability of occurrence was incorporated into Finding of Fact 24 as the factual basis for establishing that the Sunrise/SWPL N-1-1 is a probabilistic Category C event. However, the study CAISO referenced for this probability range is the December 19, 2007 probabilistic analysis conducted by SDG&E as a component of an application by SDG&E to WECC to modify the simultaneous outage of Sunrise Powerlink and SWPL (N-2) from Category C to Category D.[111] This application was successful.

In effect, the Decision uses a probability range developed by SDG&E to demonstrate that the Sunrise/SWPL N-2 is a probabilistic Category D contingency to claim that the Sunrise/SWPL N-1-1 is a probabilistic Category C contingency.[112] Independent of the 2007 SDG&E probabilistic study, WECC determined in 2012 that the Sunrise/SWPL N-2, due to the physical separation between the two lines, fit newly developed WECC requirements for reclassification as a Category D contingency.[113] In contrast to the factually erroneous Finding of Fact 24, POC is aware of no evidence in the record that the N-1-1 event is probabilistically more likely than the N-2 event.[114]

[109] SDG&E Jontry Reply Testimony, p. 3.
[110] CAISO Sparks Reply Testimony, pp. 5-6.
[111] Exhibit POC-X-CAISO-3.
[112] Ibid, p.3. Regarding the 1-in-21 year low-end probability, SDG&E stated "The lower end of the range, 21 years, would not qualify for Category D status, but SDG&E feels that after review of the Robust Line Design criteria for SWPL, the MTBF would tend towards the higher end of the range. This estimate was based on historical outage statistics for other parallel 500 kV lines with the statistics modified to consider mitigating factors that do not apply to the lines in this report."
[113] POC Opening Testimony, Exhibit 5, p. 1
[114] TURN Opening Brief, p. 12, footnote 37. "While it may be theoretically conceivable that an N -1-1 outage would have a higher probability than an N-2 outage, TURN is not aware of any evidence in the record to support basing the Commission's decision on such a theoretical possibility."

Why did SDG&E go through the effort in 2007 to demonstrate through probability analysis that the Sunrise/SWPL N-2 should be a classified as a Category D event that does not require mitigation? According to the Dec. 18, 2008 Sunrise Powerlink Final Decision:

> SDG&E was concerned that WECC would rate any line parallel to the Southwest Powerlink past that milepost (Milepost 36) as a Category C line, and SDG&E wanted the Proposed Project to obtain a Category D rating, which because it represents a higher measure of reliability, might provide further justification for the line. [115]

There is no mention of a Sunrise/SWPL N-1-1 contingency in the Sunrise Powerlink Final Decision. The use of a Sunrise/SWPL N-1-1 in the Decision is incompatible with the reliability basis for the Commission's approval of the Sunrise Powerlink. Because it results in unnecessary procurement, it also violates the Commission's duty under sections 451 and 454 to ensure just and reasonable rates. As such, the Decision constitutes a failure of the Commission to proceed in the manner required by law under section 1757(a)(2) Further, because the Decision misconstrues key evidence, the Decision's acceptance of N-1-1 as the limiting critical contingency for the San Diego area is not supported by substantial evidence in light of the entire record as required under section 1757(a)(4) and amounts to an abuse of the Commission's discretion under section 1757(a)(5).

4. *The Decision's acceptance of N-1-1 based on deference to CAISO constitutes an unlawful delegation of the Commission's regulatory authority*

In deferring to CAISO regarding the reasonableness of N-1-1, rather than exercising its independent judgment on the issue, the Commission has abdicated the statutory responsibilities assigned to it by the Legislature and unlawfully delegated its power to an interested party in these proceedings. Public Utilities Code Section 451 provides that for a new rate to be valid, *the Commission* must make a finding that the new rate is justified. Similarly, Public Utilities Code Section 1705 requires that *the Commission* consider all material issues, and particularly the public interest. The Legislature has not assigned these duties to CAISO. Indeed, CAISO's statutory purpose is to "ensure efficient use and reliable operation of the transmission grid."[116] Unlike the Commission, CAISO has no statutory mandate to protect the public interest by

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[115] Sunrise Powerlink Decision, D. 08-12-058, p. 213.

[116] Pub. Util. Code Section 345���

ensuring the reasonableness of utility rates. CAISO is merely a private corporation, with a state corporate charter to operate. But no governmental authority or responsibility attaches to this private corporation and it is not subject to the procedural or conflict of interest safeguards that apply to all other state government entities. Protecting the public interest and ensuring the reasonableness of utility rates is solely the responsibility of the Commission. The Legislature has not authorized the Commission to delegate this responsibility to CAISO.

By failing to exercise its own informed judgment based on the evidentiary record, and instead wholly deferring to CAISO, on the critical issue of the reasonableness of N-1-1, the Commission, thus, has acted outside of its authority, failed to proceed as required law, and substantially prejudiced the rights of the other parties, including POC, not to mention the rights of the ratepayers. *See, e.g., Assiniboine and Sioux Tribes of Fort Peck Indian Reservation v. Board of Oil and Gas Conservation of Montana*, 792 F.2d 782, 794-796 (9th Cir. 1986) (Bureau of Land Management unlawfully delegates its authority concerning applications for placement of oil and gas wells on tribal lands if it approves such applications based on the judgment of another entity without meaningful independent review); *Save our Wetlands v. Sands*, 711 F.2d 634, 641–43 (5th Cir.1983) (construing the requirements imposed upon agencies under the National Environmental Policy Act to consider environmental consequences of their actions and holding that an agency does not satisfy those requirements if it "reflexively rubber-stamps" reports prepared by others); *Memorial Hosp. of Roxborough v. N.L.R.B.*, 545 F.2d 351, 360-361 (3d Cir. 1976) (National Labor Relations Board unlawfully abdicated its duty under the National Labor Relations Act to determine appropriateness of a bargaining unit by accepting Pennsylvania Labor Relations Board determination without exercising the NLRB's own mandated discretion); *Sierra Club v. Lynn*, 502 F.2d 43, 59 (5th Cir.1974), *cert. denied*, 421 U.S. 994 (1975) (public or private entities may participate in preparation of environmental impact reports, as long as federal agency does not abdicate responsibilities and rubberstamp their work product); *Friends of Endangered Species, Inc. v. Jantzen*, 589 F.Supp. 113, 118–19 (N.D.Cal.1984), *aff'd*, 760 F.2d 976 (9th Cir.1985) (federal agency's delegation of environmental research to a third party is impermissible if agency fails to adequately review the work).

B. Use of Standard CAISO G-1/N-1 Planning Contingency, Correct G-1 In SDG&E Territory, and Consistent Capacity for Path 44 Would Reduce SDG&E LCR Need By About 1,400 MW

1. *G-1/N-1 Planning Standard Should Have Been Used in Modeling to Add 1,000 MW of Reliable Transmission Import Capacity on the Sunrise Powerlink*

A substantial Commission basis for approving the Sunrise Powerlink was that it would provide at least 1,000 MW of reliability under a standard G-1, N-1 contingency.[117,118] California ratepayers are paying $2 billion for the Sunrise Powerlink.[119]

Treating the Sunrise/SWPL N-1-1 as a credible contingency means that the construction of the $2 billion Sunrise Powerlink has actually decreased Southern California grid reliability. This is in direct contrast to the claims made to the Commission by SDG&E and CAISO during the Sunrise Powerlink proceeding that the Sunrise Powerlink would reduce LCR need in SDG&E territory by 1,000 MW.

The reason for the reduced grid reliability is that, with Sunrise Powerlink in operation, much more power can be imported over SDG&E's two 500 kV lines, Sunrise Powerlink and SWPL, than could be imported over SWPL alone. The loss of both of these lines in an N-1-1 event, if this event is credible, means that there is a larger hole to fill with local capacity than there was prior to the existence of the Sunrise Powerlink.

In effect, SDG&E's $2 billion Sunrise Powerlink energized in June 2012 was presented to the Commission by SDG&E and CAISO as a substantial grid reliability benefit under a G-1/N-1 standard planning contingency. However, under the Sunrise/SWPL N-1-1 contingency used in the Decision, the $2 billion Sunrise Powerlink is a grid reliability problem that precipitates a multi-billion procurement authorization of 1,500 to 1,900 MW in SCE's LA Basin and 500 to 800 MW in SDG&E territory.

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117 Sunrise Powerlink Decision, D.08-12-058, p. 28. "Pursuant to reliability criteria established by the North American Electric Reliability Corporation (NERC), SDG&E must have enough local generation resources to reliably serve all load in its Local Reliability Area after the loss of the largest generating unit in its service area followed by the loss of its most critical transmission line (the "G-1/N-1" criteria). The G-1/N-1 criteria determine SDG&E's "Local Capacity Requirement" since the Local Capacity Requirement is the amount of local generation that SDG&E must have to continue operating reliably after a G -1/N-1 event."

118 Sunrise Powerlink Decision, D.08-12-058, pp. 110-111. "In estimating Sunrise's impact on SDG&E's Local Capacity Requirement, CAISO assumes that Sunrise will cause SDG&E's "All Lines in Service" Simultaneous Import Limit to increase from 2,850 MW to 4,200 MW and its Non-Simultaneous (G-1/N-1) Import Limit to increase by 1,000 MW, from 2,500 MW to 3,500 MW.331 These increased import limits result in a potential reduction in SDG&E's Local Capacity Requirement, and thus a reduction in the amount of new in-area generating capacity and Must Run contracts needed by SDG&E to meet those requirements."

119 SC-1, p. 5.

By allowing the Utilities and CAISO to perpetrate this "bait and switch" tactic on the public and accepting the reasonableness of the Sunrise/SWPL N-1-1 contingency, the Commission undercounts the LCR need contribution of existing SDG&E transmission and generation infrastructure, and as a result authorizes unnecessary procurement for an LCR need that is already being met. This is a violation of the Commission's duty to ensure just and reasonable rates under sections 451 and 454. It also is a failure of the Commission to proceed as required by law and an abuse of the Commission's discretion under section 1757(a)(2) and (a)(5).

2. *Use of Coastal Path 44 Actual Thermal Rating of 3,200 MW Adds 700 MW of Reliable SDG&E Import Capacity Under G-1/N-1Contingency*

The only major transmission pathway in SDG&E territory that remains available to import power under the Sunrise/SWPL N-1-1 consists of the five 230 kV lines in the same right-of-way corridor that parallel Interstate 5 along the San Diego County coastline, collectively known as "Path 44". CAISO identifies the thermal capability of Path 44 as approximately 3,200 MW in the modeling it conducted of the N-1-1 contingency.[120] However, the historic path rating for Path 44 assumed by SDG&E and CAISO and used in modeling of the G-1/N-1 scenario, was 2,500 MW.[121] Mr. Sparks confirmed the 3,200 MW thermal capability of Path 44 under cross-examination.[122]

Use by CAISO of 3,200 MW of import flow on Path 44 in its modeling of the N-1-1 contingency, and use 2,500 MW of import flow on the same Path 44 in its modeling of a G-1/N-1 contingency, is a modeling inconsistency that omits 700 MW of additional reliable import power under the G-1/N-1 contingency. Use of the actual Path 44 thermal rating of about 3,200 MW when modeling the G-1/N-1 case would reduce LCR need by 700 MW under the G-1/N-1 standard contingency.

CAISO explains that before Sunrise Powerlink was built, it applied a now obsolete Path 44 rating based on "N-1 thermal limit historically employed for Path 44 for pre-Sunrise system."[123] CAISO now applies, after the construction of Sunrise Powerlink, a Path 44 power

[120] SC-1, Exhibit 2, Tables 1 and 2, p. 4 and p. 6.
[121] SC-1, Exhibit 2, Table 1, p. 4.
[122] Tr. Volume 10, p. 1514, lines 25-28, p. 1515, lines 1-5.
[123] POC Opening Testimony, Exhibit 2, p. 6

flow based on "voltage collapse criteria."[124] The result of this change by CAISO is that Path 44 carries approximately 700 MW more for N-1-1 contingency modeling purposes, with no physical change to Path 44, than it does when CAISO models the G-1/N-1 contingency. The "voltage collapse criteria" now in use by CAISO must also be applied to Path 44 when modeling the G-1/N-1 contingency with Sunrise Powerlink operational, which CAISO has not done.

The Decision's failure to properly account for the actual power flow capability of Path 44 under the G-1/N-1 contingency results in an over-assessment of need and unnecessary authorization of procurement, thus violating the Commission's duty under sections 451 and 454 to ensure just and reasonable rates. As such, the Decision constitutes a failure of the Commission to proceed in the manner required by law under section 1757(a)(2). Further, the failure to properly account for the thermal capability of Path 44 is not supported by substantial evidence in light of the entire record as required under section 1757(a)(4) and amounts to an abuse of the Commission's discretion under section 1757(a)(5).

3. *Proper Categorization of G-1 in SDG&E Territory Would Result in Loss of Only 260 MW Steam Generator at Otay Mesa Combined Cycle Plant, Not Entire 604 MW Plant as the Decision Assumes*

In addition, CAISO's erroneous categorization of outages at Palomar Energy and Otay Mesa combined cycle plants, the two combined cycle plants in SDG&E service territory, as presumptive "whole plant" outages for LCR planning purposes conflicts with the clear statement of the Federal Electricity Regulatory Commission (FERC) on the capabilities of these two combined cycle plants.[125] This matters when the CAISO board-approved G-1/N-1 planning standard is applied. CAISO acknowledgement of the design capabilities of the two combine cycle plants, which allow the plants to continue operating as simple-cycle units with the steam turbine-generator in forced outage, would increase the LCR capacity in the SDG&E load pocket by approximately 344 MW under the CAISO-approved standard G-1/N-1 planning contingency in SDG&E territory.[126] Because the Decision overvalues the loss that would be caused by outages at Palomar and Otay Mesa, the Decision over-assesses LCR need and authorizes unnecessary procurement, thus violating the Commission's duty under sections 451 and 454 to

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[124] Ibid.

[125] SC-1, Exhibit 1.

[126] SC-1 (Opening Testimony of Bill Powers On Behalf of Sierra Club California

ensure just and reasonable rates. As such, the Decision constitutes a failure of the Commission to proceed in the manner required by law under section 1757(a)(2). Further, the Decision's overvaluation of the losses caused by Palomar and Otay Mesa outages is not supported by substantial evidence in light of the entire record as required under section 1757(a)(4) and amounts to an abuse of the Commission's discretion under section 1757(a)(5).

4. *The Commission Failed to Include a Finding That No Outage "Ripple Effect" Occurs from SDG&E to SCE Territory if G-1/N-1 Is the Contingency Standard*

The Commission adopted a power flow model critical contingency in the Decision (N-1-1) that conflicts with the critical contingency (G-1/N-1) used as a basis for its decision to approve the Sunrise Powerlink and undermines the basis for the prior approval. The Sunrise Powerlink-Southwest Powerlink N-1-1 "ripple effect" felt as an N-1 in SCE territory,[127] the basis for joint SCE-SDG&E power flow modeling in Track 4, would disappear under a G-1/N-1 contingency, as power would continue to flow over the Sunrise Powerlink under contingency conditions and not be rerouted through the SCE transmission system.[128] As SCE explains:[129]

> A Category C contingency, where two 500 kV transmission lines that feed SDG&E are lost, will reroute power to the remaining lines that feed SDG&E (see No. 1 in Figure III-3). The rerouted power flows through lines in the LA Basin and produce thermal overloads and voltage deviation violations (see No. 2).

Under a standard G-1, N-1 planning contingency in SDG&E territory, a Path 44 path rating that accurately reflects the thermal capability of the two lines, and an accurate G-1 capacity for the San Diego area combined cycle units, SDG&E territory would have more than 1,400 MW of LCR capacity that is not counted when the Sunrise Powerlink/SWPL N-1-1 contingency is assumed. There would be no determination of need in either SDG&E territory or SCE territory if a standard G-1, N-1 planning contingency is assumed, an accurate path rating is applied to Path 44, and the designated G-1 unit reflects the inherent design capability of the two San Diego combined cycle plants. The Commission fails to ensure just and reasonable rates by undercounting the LCR need contribution of existing SDG&E transmission and generation

[127] Tr. Volume 13, p. 1934, lines 5-11.

[128] SCE Opening Testimony, Figure p. 25.

[129] Ibid, p. 24.

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infrastructure in CAISO model, and as a result authorizes unnecessary procurement for an LCR need that is already being met. This is a violation of the Commission's duty to ensure just and reasonable rates under Sections 451 and 454. It also is a failure of the Commission to proceed as required by law and an abuse of the Commission's discretion under section 1757(a)(2) and (a)(5).

V. THE DECISION ERRONEOUSLY AUTHORIZES PROCUREMENT THROUGH BILATERAL CONTRACTS

The Decision authorizes the utilities to procure resources through bilateral contracts,[130] reasoning that SCE was allowed to procure resources with bilateral contracts in Track 1.[131] However, there are major differences between the Track 1 and Track 4 authorization.

Track 1 authorized a specified minimum amount of natural gas resources, whereas the Track 4 Decision importantly finds that all of the need could be met with preferred and energy storage resources.[132] Bilateral contracts are not an appropriate way to meet the Track 4 need because they will not allow all available preferred and energy storage resources to be considered. Rather, bilateral contracts will target only one entity and likely one type of resource. Bilateral contracts will also not facilitate compliance with the Loading Order and Section454.5 of the Code, which requires that energy efficiency; demand response and renewable resources are procured before fossil fuel resources.

The Decision also importantly requires that all applications must demonstrate "[c]onsistency with the Loading Order, including a demonstration that it has identified each preferred resource and assessed the availability, economics, viability and effectiveness of that supply in meeting LCR need."[133]

Allowing bilateral contracts will effectively negate the language in the Decision requiring compliance with the Loading Order and finding that preferred resources could fill the unmet need. Track 1 also limited bilateral procurement to the narrow situations that meet the requirements of Section 454.6 of the Public Utilities Code,[134] whereas the language of the

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[130] Ex. CESA-1 (Lin Opening Testimony).
[131] Decision, p. 92.
[132] Comparison of Decision Ordering Paragraph 3, p. 144, with Track 1 Authorization, D.13-02-015.
[133] Decision Ordering Paragraph 8, p. 145
[134] D.13-02-015, Ordering Paragraph 9.

Decision does not explicitly limit bilateral contracts to that situation. Rather, the Decision states that: [SCE] and [SDG&E] are authorized to procure bilateral cost-of-service contracts to meet authorized local capacity requirements as specified in this Order, including bilateral contracts consistent with the provisions of Public Utilities Code Section 454.6.79. [135]

Generally, allowing bilateral contracts will likely result in contracts that do not represent the best deal for ratepayers or the environment. Such contracts will not prioritize preferred resources, energy efficiency, and demand response over gas-powered procurement, in violation of section 454.5(b)(9)(c), the State's Energy Action Plan, and the Commission's own Loading Order. Nor will they ensure just and reasonable rates, violating the Commission's duty to ratepayers under sections 451 and 454. As such, by authorizing bilateral contracts the Commission has failed to proceed as required by law and abused its discretion in violation of section 1757(a)(2) and (a)(5).

VI. BY REJECTING POC'S MOTION FOR OFFICIAL NOTICE AND STRIKING POC'S OPENING AND REPLY BRIEFS, THE COMMISSION FAILED TO PROCEEDAS REQUIRED BY LAW, ABUSED ITS DISCRETION, AND VIOLATED POC'S DUE PROCESS RIGHTS.

A. Denial of POC's Request for Official Notice Was a Legal Error and Abuse of Discretion.

On November 4, 2013, POC submitted a Motion seeking Official Notice of three official WECC policy Documents setting forth WECC's official PBRC process.[136] These documents were identified as POC-4, POC-5, and POC-6.

ALJ Gamson rejected POC's Motion in a one-sentence, corrected email ruling dated November 15, 2013, stating in full:

> The November 4, 2013 Motion of the Protect Our Communities Foundation for Official Notice of Exhibits, identified as Exhibits POC-4, POC-5, and POC-6, is hereby denied. These items will not be admitted into evidence in this proceeding. [137]

[135] Decision Ordering Paragraph 3, p. 144.
[136] These documents were titled: Reliability Performance Evaluation Work Group – Phase I Probabilistic Based Reliability Criteria Implementation Procedure, dated June 14, 2001 (Previously marked for therecord as POC-4); Seven Step Process for Performance Category Upgrade Request, dated October 2004(Previously marked for the record ads POC-5); WECC Board of Directors Request Regarding Performance Category Upgrade Request, dated February 20, 2013 (Previously marked for the record as POC-6).
[137] ALJ Gamson's original email ruling, dated November 15, 2013, erroneously referred to exhibits "POC-3, POC-4, and POC-5."

This ruling provided no explanation as to why POC's Motion was denied.

The Decision affirms ALJ Gamson's ruling, citing to two arguments from the Utilities' November 6, 2013 Response to POC's Motion: that "the documents did not qualify for Judicial Notice;" and that "the documents were not relevant because they predated current NERC standard or were otherwise not applicable to the facts at hand."[138] Both of these justifications are in error and an abuse of the Commission's discretion.

As POC explained in its Motion, POC-4, POC-5, and POC-6 are officially noticeable. Rule 13.9 of the Commission's Rules of Practice and Procedure provides that "Official notice may be taken of such matters as may be judicially noticed by the courts of the State of California pursuant to Evidence Code section 450 et seq." California Evidence Code section 452 states that Judicial notice may be taken of "Regulations and legislative enactments issued by or under the authority of the United States or any public entity in the United States."

The documents submitted by POC were regulations or enactments issued under the authority of the United States and by a public entity in the United States. WECC's transmission planning rules and policies are part of a comprehensive transmission planning regulatory scheme implemented by the FERC, NERC, and WECC. FERC is the Federal agency responsible for regulating the national electric grid.[139] Pursuant to the Federal Power Act,[140] FERC has delegated its regulatory authority regarding reliability standards to NERC, which in turn has delegated this regulatory authority to WECC. FERC explains the relationship between FERC, NERC, and WECC as follows:

> The Energy Policy Act of 2005 (EP Act 2005) Established section 215 of the Federal Power Act, which authorized the Federal Energy Regulatory commission (Commission or FERC) to certify an Electric Reliability Organization (ERO) for the purpose of proposing reliability standards for the bulk-power system in the continental United States subject to the Commission's approval. After they are approved by the Commission, the standards are mandatory for the users, owners, and operators of the bulk power system and are enforced by the ERO under the Commission's oversight. The statute also authorized the ERO to delegate enforcement authority to a Regional Entity, subject to Commission approval. In July 2006, the Commission certified the North American Electric Reliability Corporation (NERC) as the ERO. And on June 5, 2007, the Commission accepted executed agreements between NERC and eight Regional Entities, including the

[138] D.14-03-004 at p. 20
[139] 16 U.S.C. Section 824 et. seq
[140] 16 U.S.C. Section 791(a) et. seq.

Western Electricity Coordinating Council (WECC), in regard to the delegation of NERC's ERO standards development and enforcement authorities to such entities.[141]

Thus, for utilities within WECC's jurisdiction, WECC's rules, guidelines, regulations, and policies relating to compliance with NERC standards are regulations or enactments issued under the delegated authority of FERC, a public regulatory entity in the United States, by WECC, a public entity in the United States.

The documents submitted as POC-4 and POC-5 set forth WECC's official, board-approved PBRC policy, which allows for probabilistic exceptions to contingency categorization based on NERC's official categories. POC-6 is an official WECC report that applies POC-4 and POC-5 and identifies the documents as official WECC policies approved by WECC's Board.

The Decision errs in affirming ALJ Gamson's denial of the Motion based on the Utilities' argument that the documents in question do not qualify for judicial notice. WECC does not maintain a formal code of regulations. Instead, official WECC regulatory policies, including those enacted pursuant to delegated federal authority, are set forth in policy documents such as POC-4, POC-5, and POC-6. These official policy documents are publically available on WECC's website.[142] Documents setting forth such policies are noticeable.

The Decision further errs in affirming the denial of the Motion based on the Utilities argument that "the documents were not relevant because they predated current NERC standard or were otherwise not applicable to the facts at hand." Neither the Decision nor the Utilities' Motion provides any explanation as to why WECC's adoption of the PBRC process prior to the adoption of the most recent revision to NERC's standards would make the PBRC process inapplicable to the current standards. This claim is directly contradicted in the evidentiary record, which shows that SDG&E sought a PBRC recategorization of the proposed Sunrise Powerlink and Southwest Powerlink in 2008, three years after the NERC standards relied upon by the Utilities were implemented.[143] The Utilities' claim that the PBRC process set forth in POC-5 doesn't apply to the N-1-1 contingency at issue in this proceeding is unsupported by

[141] Exhibit SC-01 (Powers Opening Testimony), Exhibit 1, pp. 1-2
[142] https://www.wecc.biz/library/default.aspx
[143] The Utilities rely on NERC reliability standard TPL-003, which was first effective April 1, 2005

citation to any WECC policy or any other authority, and is contradicted by CAISO's admission that the PBRC process does apply.[144]

B. Striking Of POC's Opening and Reply Briefs Was a Legal Error, Abuse of Discretion, and Violation of POC's Due Process Rights

On December 4, 2013, SCE and SDG&E (the "Joint Utilities") filed a Motion to Strike several sections of POC's Opening Brief on the grounds that these sections relied on materials excluded from the Evidentiary record by ALJ Gamson's November 14, 2013 ruling denying POC's November 4, 2013 motion for Official Notice.[145]

The Joint Utilities' Motion to strike was overly broad, as only two of the six sections of POC's Opening Brief that the Utilities sought to strike cited to documents not contained in the evidentiary record, specifically, exhibits POC-4, POC-5, and POC-6. The remaining four sections cited to and relied upon exhibit POC-3, which is part of the evidentiary record. In seeking to strike these sections citing exhibit POC-3, the Joint Utilities erroneously relied on ALJ Gamson's November 14 ruling, which erroneously referred to exhibits "POC-3, POC-4, and POC-5" rather than his corrected November 15 ruling, which referred to exhibits "POC-4, POC-5, and POC-6."

The remaining two sections of POC's Opening Brief properly cited to official WECC policies as authority, not evidence. Evidence is "testimony, writings, material objects, or other things presented to the senses that are offered to prove the existence or nonexistence of a fact."[146] POC's Brief, in contrast, cites to the WECC documents setting forth WECC's PBRC process, an official regulatory policy, as *authority*.[147]

As explained above, WECC's transmission planning rules and policies are part of a comprehensive transmission planning regulatory scheme implemented by the FERC, NERC, and WECC. FERC is the Federal agency responsible for regulating the national electric grid. Pursuant to the Federal Power Act, FERC has delegated its regulatory authority regarding reliability standards to NERC, which in turn has delegated this regulatory authority to WECC.

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[144] Tr. Vol. 11, p. 1562, lines 15-21.
[145] Email Ruling of ALJ Gamson,, Dated Novemer 14, 2013
[146] Cal. Evid. Code § 140.
[147] As POC explained in its Response to the Joint Motion, "Although these documents set forth an official WECC regulatory policy, and as such notice and/or inclusion in the evidentiary record is not necessary, POC made the decision to seek official notice of these documents out of an abundance of caution." At p. 3

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Under this scheme, WECC's rules and policies are mandatory and have the force of law. Thus, for utilities within WECC's jurisdiction, WECC exercises federal regulatory authority regarding the establishment, implementation, and enforcement of reliability standards and related policies.

The fact that the PBRC process exists and is an official WECC policy that allows for individual exceptions to mandatory NERC/WECC reliability standards is not contested by any party to this proceeding. In cross examination, both CAISO witness Sparks[148] and SDG&E witness Jontry[149] admitted that the PBRC process exists and is an official WECC policy that allows for such individual exceptions. The evidentiary record in this proceeding includes a PBRC application that SDG&E filed with WECC, seeking an exception to the categorization of the N-2 outage of Southwest Powerlink and the proposed Sunrise Powerlink transmission lines as a NERC/WECC Category C event.[150]

As an official WECC policy that allows utilities to apply for individual exceptions to mandatory NERC/WECC reliably standards, the PBRC process is an essential part of the FERC/NERC/WECC regulatory scheme regarding system reliability. As such, the official WECC documents setting forth the PBRC process are properly viewed as regulatory authority, which may be directly cited to. The Commission acted contrary to law, abused its discretion, and violated POC's due process rights by striking POC's opening and Reply briefs.

VII. IMPLICATION IN DECISION THAT LACK OF SUFFICIENT LOCAL CAPACITY MAY HAVE PLAYED A ROLE IN ACTUAL BLACKOUTS IS ERRONEOUS

The Decision references the September 2011 blackout in SDG&E territory to justify requiring new resources as a backdrop to its discussion of the advantages/disadvantages of maintaining sufficient local supply with no load shedding or to consider load shedding as one response to address the Sunrise/SWPL N-1-1 contingency.[151] The implication in Decision that lack of sufficient local capacity may have played a role in actual September 2011 blackout in SDG&E territory is erroneous.

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[148] Transcript, p. 1559, line 14 to p. 1560, line 22
[149] Transcript, p. 1773, line 25 to p. 1774, line 2
[150] Ex. POC X CAISO 3
[151] Decision, p. 42.

SDG&E territory has experienced two major blackouts in the last four years.[152] Both blackouts occurred under single contingency conditions with large amounts of unused local capacity available. The first blackout was caused by the CAISO when it erroneously scheduled a generator that had already notified CAISO that it was unavailable.[153] This blackout occurred under low demand conditions just after midnight on April 1, 2010. FERC ordered CAISO to pay a $200,000 fine for this avoidable error.[154] The second blackout occurred on September 8, 2011 and was precipitated by the loss of a single 500 kV transmission line, SDG&E's Southwest Powerlink.[155] Inadequate grid management procedures were cited as the cause of this blackout by FERC, not lack of generation or transmission resources.[156] On this hot, high demand day, SDG&E was relying on less than 50 percent of the local capacity available to it in its service territory, only 1,543 MW out of 3,350 MW available.[157] SDG&E demand at the time of the blackout was 4,293 MW.[158] Most of this demand was being met by 2,750 MW of imported power when the blackout occurred. A larger quantity of unused local capacity would have made no difference in preventing either blackout. Thus, the Decision's entire justification for the additional procurement it authorizes is not supported by the substantial evidence in the record.

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[152] POC Opening Testimony, Exhibits 10 and 11.
[153] POC Opening Testimony, Exhibit [illegible] pp. [illegible]
[154] POC Opening Testimony, Exhibit 10, p. 5.
[155] POC Opening Testimony, p. 14.
[156] POC Opening Testimony, pp. 13-14.
[157] POC Opening Testimony, Exhibit 11, p. 20, p. 24, and p. 60. SDG&E load at time of blackout = 4,293 MW. Import power level at time of blackout = 2,750 MW along SDG&E Southwest Powerlink. Amount of local generation in use at time of blackout = 4,293 MW – 2,750 MW = 1,543 MW.
[158] *Ibid,* p. 60.

VIII. CONCLUSION

In light of the multiple unlawful and erroneous aspects of D.14-03-004 identified above, the Commission should grant rehearing of D.14-03-004 in order to expeditiously correct these errors.

Respectfully Submitted,

Dated: May 22, 2014

/S/

David A. Peffer, Esq.
Protect Our Communities Foundation
4452 Park Boulevard, Suite 209
San Diego, CA 92116
david.a.peffer@gmail.com

EXHIBIT 1

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

DECLARATION OF DAVID PEFFER IN SUPPORT OF POC'S APPLICATION FOR REHEARING

I, David A. Peffer, declare and state that the following is based on my own personal knowledge and if called upon as a witness I could and would competently testify thereto:

1. I am an attorney authorized to practice law in the State of California. I represent the Protect Our Communities Foundation in the Commission's 2012 LTPP proceeding, R.12-03-014.

2. Attached hereto is a true and correct copy of the cover page, table of contents, and pages 1-16 of the California Independent Operator's (CAISO's) 2014 Summer Loads & Resources Assessment, dated May 9, 2014, and downloaded from CAISO's website (http://www.caiso.com/Documents/2014SummerAssessment.pdf) on May 22, 2014.

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I declare under penalty of perjury and under the laws of the state of California that the foregoing is true and correct. Executed this day, May 22, 2014, in San Diego, California.

Dated: May 22, 2014

/S/

David A. Peffer, Esq.
Protect Our Communities Foundation
4452 Park Boulevard, Suite 209
San Diego, CA 92116
david.a.peffer@gmail.com

2014 SUMMER LOADS & RESOURCES ASSESSMENT

California ISO
Shaping a Renewed Future

May 9, 2014

Prepared by: Infrastructure Development

Table of Contents

I. EXECUTIVE SUMMARY

The *2014 Summer Loads and Resources Assessment* provides an analysis of the upcoming summer supply and demand outlook in the California Independent System Operator (ISO) balancing authority area. The ISO works with state agencies, generation and transmission owners, load serving entities, and other balancing authorities to formulate the summer forecast and identify any issues regarding upcoming operating conditions. The loads and resources assessment considers the conditions across the entire ISO balancing authority area as a whole (representing about 80 percent of California), and then further considers separately the situations in the Northern California zone (North of Path 26 or NP26) and the Southern California zone (South of Path 26 or SP26). The drought impact in California on power supply and local reliability concerns for southern Orange and San Diego counties due to the loss of the San Onofre Nuclear Generation Station are two of the key issues in 2014 and are addressed in this report

Impact of California Drought on Summer Power Supply

The 2014 water year is one of the most severe droughts on record according to California Department of Water Resources. As of April 29, 2014, the statewide hydrologic conditions were summarized as: 56% of average precipitation; 20% of average snowpack water content; and 63% of average reservoir storage.[1] These drought conditions will limit the capability of the state's hydroelectric resources and may cause up to 1,150 MW of thermal units to shut down due to water supply curtailments.[2]

However, these potential supply limitations should not materially impact the reliability of the ISO system this summer due to significant generation additions, sufficient energy imports, and moderate peak demand growth. The main impact from the drought during 2014 summer will be an increase in natural gas generation, which could result in an increase in energy prices, and increased greenhouse gas emissions. However, the unusually dry conditions across the state do create a heightened risk of wildfires, which could impact the use of major transmission lines during periods of critical summer peak demand. Thus, wildfires could create grid reliability challenges over the summer. Some of the key factors supporting this conclusion are summarized below.

[1] http://cdec.water.ca.gov/cgi-progs/reports/EXECSUM

[2] Climate change studies suggest this is the start of a long-term trend toward drier, hotter conditions in California. This trend in addition to increasing deployment of renewable resources underscores the importance of ensuring California has adequate grid infrastructure going forward to both offset the impacts of climate change and effectively integrate renewable resources. To address this challenge, the ISO is taking a more sophisticated approach to system planning where generic capacity and traditional planning reserve margins are less relevant and the primary focus is on ensuring California has sufficient dispatch and flexibility capabilities within the resource fleet to reliability operate the system and achieve state energy policy goals. This study work is being used in ongoing CPUC proceedings to inform resource procurement decisions.

- **ISO Hydro Generation Derate**

  In the Final Net Qualifying Capacity (NQC) Report for Compliance Year 2014[3], ISO total hydro NQC in August is 7,666 MW (capacity available for peak based on state's resource adequacy program). The NQC is the maximum capacity eligible and available for meeting the CPUC resource adequacy requirement. The ISO determines the NQC by applying performance criteria and deliverability restrictions as outlined in the ISO tariff and the applicable business practice manual. However, as a result of the drought, and based on discussions held with Pacific Gas and Electric and Southern California Edison, the two largest hydro capacity owner/operators in the ISO, the ISO has determined that a hydro derate in the amount of 1,370 MW (normal scenario) to 1,669 MW (extreme scenario) should be applied to the net qualifying capacity of 7,666 MW. There is only 44 MW of NQC hydro generation located in San Diego and Orange Counties and the majority of this generation is pumped storage. Consequently, drought conditions will have little impact on local resource adequacy in the San Diego and Orange County areas.

- **Potential Thermal Restriction**

  In considering the drought situation for the summer of 2014, the ISO is following the potential impact of thermal units being out of service due to water supply curtailments. Among the 260 thermal power plants greater than 20 MW, three facilities in Northern California totaling 1,150 MW have been identified to be at risk of having water supply curtailments. The ISO will work with state and local agencies to monitor these facilities through the summer. Water supplies to thermal generation will likely be of a greater concern in 2015 if the current drought continues.

- **Imports from Outside California**

  As of April 29, 2014, Northwest River Forecast Center projected April to August reservoir storage in Columbia - Dalles Dam to be 107% of average.[4] The Pacific Northwest hydro surplus energy sales into the ISO are anticipated to be in the normal to above normal range for 2014 to make up for some of California's low hydro generation. The California – Oregon Intertie (COI) thermal limit could be a limiting factor for these imports. It is anticipated that dynamically scheduled and other generation from the Four Corners will be available for surplus energy sales into the ISO during the peak hours. The Southern California Import Transmission (SCIT) thermal limit could be a limiting factor for these imports.

- **Natural Gas and Solar Generation Additions**

  A total of 3,243 MW additional generations are expected to enter commercial operation by June 1 2014, 2,258 MW in SP26 and 985 MW in NP26, This 3,243 MW comes from 3,555 MW of new generation that went into commercial operation since last summer, the retirement of the 650 MW of generation at Morro Bay, and an additional 338 MW that is expected to become commercial operation by June 1, 2014.

[3] *Net Qualifying Capacity (NQC).* Retrieved from website: http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx

[4] http://www.nwrfc.noaa.gov/water_supply/ws_forecasts.php?id=TDAO3

Of the 3,243 MW, 61% is solar, 32% is natural gas, and 7% is in other categories. This will help to offset the anticipated hydro derate in 2014.

Local Reliability Concerns due to SONGS Outage

The permanent retirement of the San Onofre Nuclear Generating Station was announced on June 7, 2013. This further validated the steps taken in 2012 to prepare the system for the summer of 2013 in anticipation of SONGS not returning to service. Those steps included the completion of several transmission and voltage support enhancements in the LA Basin area.

While additional approved mitigations are expected to begin coming into service for the summer of 2015, no additional transmission measures are available for the summer of 2014. With continued modest load growth, local reliability conditions in the south Orange and San Diego counties are likely to be marginally more challenging this summer compared to last.

If critical high-voltage transmission lines are out of service, due to wildfires or other conditions, deficient voltage levels may occur under peak load conditions that could trigger localized customer outages. Furthermore, the absence of SONGS results in potential overloading of local transmission lines under certain contingencies.

Until longer term mitigations are in place, southern Orange County and San Diego will remain susceptible to reliability concerns and will require close attention during summer operations – particularly during critical peak days and in the event of wildfires that could potentially force transmission lines out of service.

During these types of conditions, both demand response programs and Flex Alert conservation appeals will likely be used to lessen the strain on the grid.

Overall ISO System-wide and Zonal Reliability

Even with the drought concerns, the summer assessment projects adequate supply for meeting 2014 summer peak demand for the ISO grid at the system wide level and for the NP26 and SP26 regions when considered independently. This projection is based on examining the operating reserve margins under normal and extreme scenarios.

The summer 2014 supply and demand outlook for the entire ISO system, NP26 and SP26 are shown in *Tables 1 through 3*. Planning reserve margins under the normal peak demand scenario are projected to be 34.4% for the ISO system, 35.9% for SP26, and 36.3% for NP26 (*Table 1*).

Operating reserve margins under the normal summer conditions are expected to be 23.8% for the ISO system 28.2% for SP26, and 22.7% for NP26 (*Table 2* and *Figure 1*). Both the planning reserve margin and the normal operating reserve margin are projected to be greater than the California Public Utility Commission's 15% resource adequacy requirement for planning reserve margin.

The 2005 to 2014 operating reserve margins under the normal scenario projected prior to each summer are shown in *Figure 2*. It is worth mentioning that the operating reserve margin projected for 2014 is the second largest in the past ten years. The normal scenario for operating reserves is defined for system and zonal conditions as moderate net imports, 1-in-2 generation outages, and 1-in-2 peak demand. A 1-in-2 event means the event has an equal probability of the outcome falling below the forecast value or exceeding the forecast value.

Under an extreme scenario, operating reserve margins are projected to drop to 13.6% for the ISO system, 15.1% for SP26 and 7.6% for NP26 (*Table 3* and *Figure 1*), which are above the firm load shedding threshold of 3%. The extreme scenario is defined as low net imports, 1-in-10 generation outages, and 1-in-10 peak demand. A 1-in-10 event means the event has a 90% probability of the outcome being less than or equal to the forecast value, or conversely, a 10% probability of the outcome being greater than or equal to the forecast value. Operating reserve margins for each zone are for informational purposes as the system is dispatched on a one-system basis. The methodology for assessing transfers between the NP26 and SP26 zones that has been employed in this and past Summer Assessments is based on historical flows, which does not adequately address evolving conditions with drought impacts most strongly felt in NP26. A revised methodology utilizing modeled transfers under projected load and resource scenarios will be employed in next year's Summer Assessment.

The projected probability of experiencing involuntary load curtailments due to low operating reserve margins in summer 2014 is 0% for ISO system, 0% for SP26 and 0.1% for NP26, assuming moderate imports and a high hydro derate. These projected probabilities are based on historical generating resource availabilities and the forecast range of weather driven peak demand levels and do not include load curtailments due to transmission lines being out of service due to wildfires or other contingencies.

The ISO summer 2014 peak demand is projected to reach 47,351 MW during 1-in-2 weather conditions, which was 646 MW more than 2013 weather normalized peak of 46,705 MW. The weather normalized peak is an estimate of what the peak would have been under normal weather conditions. The increase in the ISO peak demand forecast is a result of a moderate economic recovery forecast from Moody's Analytics.

The ISO projects that 53,950 MW of net qualifying capacity (NQC) will be available for summer 2014 (*Table 7*). A total of 3,243 MW of additional generation since last year's report is made up of 3,555 MW of new generation that reached commercial operation and the retirement of 650 MW of generation at Morro Bay between June 1, 2013 and April 22, 2014 and an additional 338 MW that is expected to become commercial operation during April 23, 2014 to June 1, 2014 timeframe.

An estimated 2,066 MW of demand response and interruptible load programs will be available to be deployed during summer 2014. Demand response can reduce summer peak demands and provide grid operators with additional system flexibility during periods of limited supply. Demand response can provide economic day-ahead and real-time energy and ancillary service.

The 2014 summer imports are projected to vary from 8,500 MW to 11,000 MW for the ISO, 8,800 MW to 11,300 MW for SP26, and 1,300 MW to 3,000 MW for NP26. The projected 2014 moderate imports for the ISO is 9,000 MW, which is lower than last year. Having sufficient imports are essential in maintaining system reliability under extreme conditions.

Table 1

Planning Reserve Margins

Summer 2014 Supply & Demand Outlook (Planning Reserve Margins)			
Resource Adequacy Planning Conventions	**ISO**	**SP26**	**NP26**
Existing Generation[5]	53,612	26,178	27,434
Retirement	0	0	0
High Probability Addition[6]	338	261	77
Hydro Derate (below NQC)	(1,370)	(281)	(1,089)
Net Interchange (Moderate)[7]	9,000	9,200	2,100
Total Net Supply (MW)[8]	61,580	35,358	28,522
DR & Interruptible Programs[9]	2,066	1,341	725
Demand (1-in-2 Summer Temperature)[10]	47,351	26,994	21,452
Planning Reserve Margin[11]	**34.4%**	**35.9%**	**36.3%**

Table 2

Normal Scenario Operating Reserve Margins

Summer 2014 Outlook - Normal Scenario 1-in-2 Demand, 1-in-2 Generation Outage and Moderate Imports			
Resource Adequacy Conventions	**ISO**	**SP26**	**NP26**
Existing Generation	53,612	26,178	27,434
Retirement	0	0	0
High Probability Additions	338	261	77
Hydro Derate (below NQC)	(1,370)	(281)	(1,089)
Outages (1-in-2 Generation)[12]	(5,030)	(2,105)	(2,921)
Net Interchange (Moderate)	9,000	9,200	2,100
Total Net Supply (MW)[13]	56,550	33,253	25,601
DR & Interruptible Programs	2,066	1,341	725
Demand (1-in-2 Summer Temperature)	47,351	26,994	21,452
Operating Reserve Margin[14]	**23.8%**	**28.2%**	**22.7%**

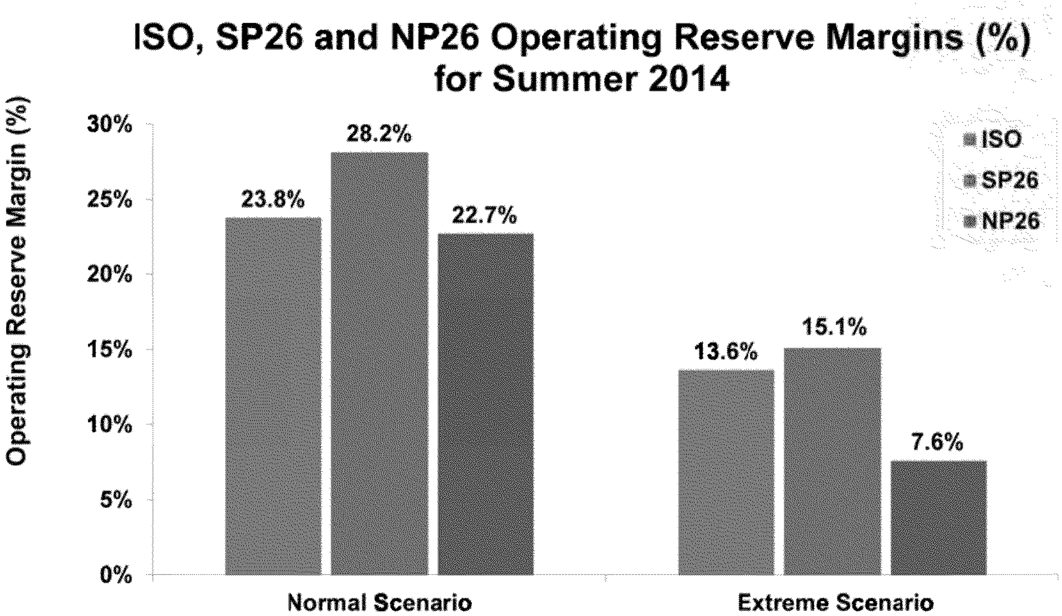
[5] Refer to Table 7. Conventional 74%, Renewable 26%.
[6] Refer to Table 6.
[7] Refer to Table 10. Net Interchanges of ISO, SP26 and NP26 are not coincident.
[8] Total Net Supply = Existing Generation + High Probability Additions – Hydro Derate – Retirements + Net Interchange
[9] Refer to Table 11.
[10] Refer to Table 12.
[11] Planning Reserve Margin = [(Total Net Supply + Demand Response + Interruptible) / Demand] – 1
[12] Refer to Table 8. Outages of ISO, SP26 and NP26 are not coincident.
[13] Total Net Supply = Existing Generation + High Probability Additions – Hydro Derate – Retirements – Outages + Net Interchange
[14] Operating Reserve Margin = (Total Net Supply + Demand Response + Interruptible) / Demand -1

Table 3

Extreme Scenario Operating Reserve Margins

Summer 2014 Outlook - Extreme Scenario 1-in-10 Demand, 1-in-10 Generation Outage and Low Imports			
Resource Adequacy Conventions	**ISO**	**SP26**	**NP26**
Existing Generation	53,612	26,178	27,434
Retirement	0	0	0
High Probability Additions	338	261	77
High Hydro Derate (below NQC)	(1,669)	(342)	(1,328)
High Outages (1-in-10 Generation)	(6,478)	(3,406)	(4,126)
Net Interchange (Low)	8,500	8,800	1,300
Total Net Supply (MW)	54,303	31,491	23,357
DR & Interruptible Programs	2,066	1,341	725
High Demand (1-in-10 Summer Temperature)	49,601	28,522	22,377
Operating Reserve Margin	**13.6%**	**15.1%**	**7.6%**

Figure 1



Notes:
⇨Demand based on 1-in-2, or 1-in-10 Weather.
⇨All Demand Response and Interruptible Load has been utilized.
⇨At Stage 3 Emergency firm load is shed to maintain 3% Operating .

Figure 1 shows adequate operating reserve forecast margins under the normal and extreme scenarios. The operating reserve margins for ISO, SP26 and NP26 are projected to be above the 3% firm load shedding threshold in all scenarios.

Figure 2

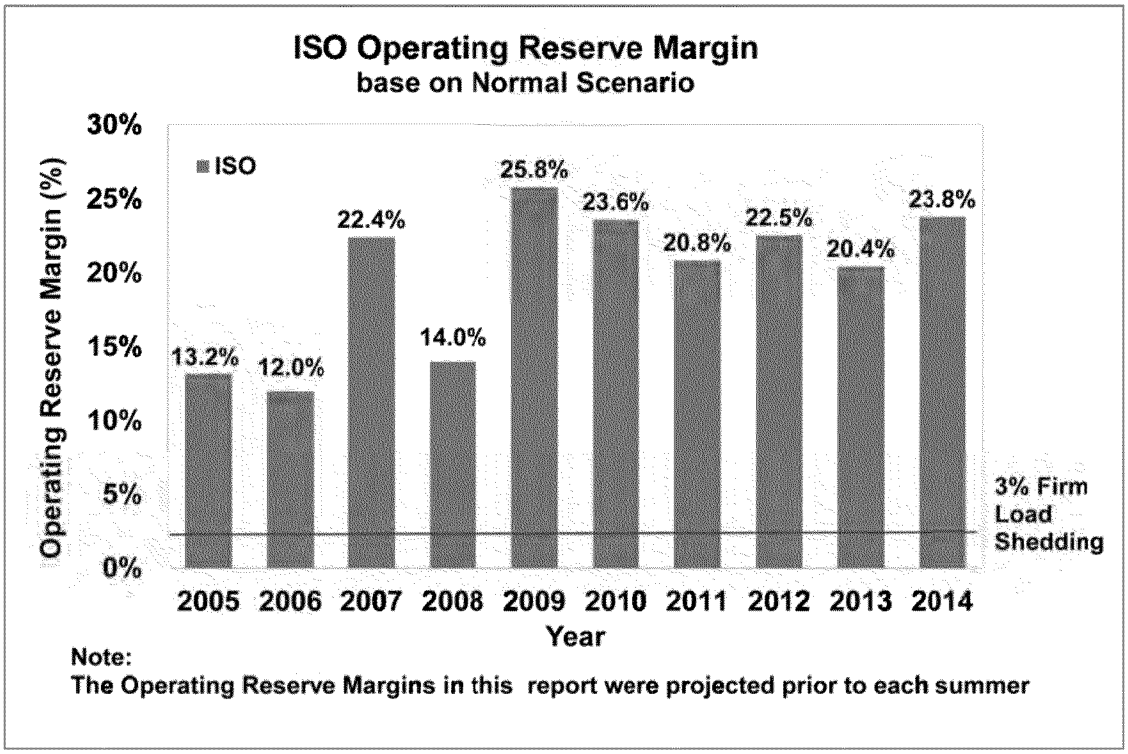


Figure 2 shows forecasts of normal operating reserve margins have remained ample and fairly consistent since 2009.

Producing this report and publicizing its results is one of many activities the ISO undertakes each year to prepare for summer operations. Other activities include coordinating meetings on summer preparedness with the WECC, Cal Fire, natural gas providers and neighboring balancing authorities. The ISO's ongoing relationships with these entities help to ensure everyone is prepared during times of system stress.

Significant amounts of new renewable generation has reached commercial operation and this trend is expected to continue as new renewable generation comes online to meet the state's 33% renewables portfolio standard (RPS). A certain amount of flexible and fast responding resources will need to be maintained on the system to ensure reliable operation in the transition to the RPS.

The roughly 10,517 MW of natural gas fired capacity subject to the once-through-cooling regulation, which will require coastal power plants that use ocean water for cooling to be retired, retrofitted or repowered, is an ongoing issue that also needs to be addressed. The ISO is working closely with state agencies and plant owners in evaluating the reliability impacts of implementing these regulations to ensure electric grid reliability is maintained throughout the transition. The ISO plans to include assessments of the adequacy of flexible capacity in future Summer Loads and Resources Assessment reports.

II. SUMMER 2013 REVIEW

Demand

The recorded 2013 summer peak demand reached 44,941 MW on June 28, 2013. Adjusting for the normalized weather conditions, this translates into a peak load of 46,705 MW for ISO in 2013, an increase of 30 MW, or 0.06% from the 46,675 MW of 2012 summer peak demand. The SP26 summer peak demand was 27,058 MW and NP26 peak demand reached 20,928 MW. The annual peaks for the ISO, SP26 and NP26 happened on June, July and September, respectively. The fact that the annual peaks did not occur coincidently is due to a number of factors, with weather being the primary contributing factor.

Figure 3 shows ISO, SP26 and NP26 actual monthly peak demand from 2006 to 2013. The ISO summer peak dropped each year from 50,085 MW in 2006, which was high because of extreme weather conditions and a stronger economy, to 45,809 MW in 2009 as demand moderated during the recession. Demand has fluctuated since 2009 based on changing economic, demographic, and weather conditions. The ISO, SP26 and NP26 daily peaks from June to September 2013 are shown in *Appendix A: 2013 Summer Peak Load Summary Graphs.*

Figure 3

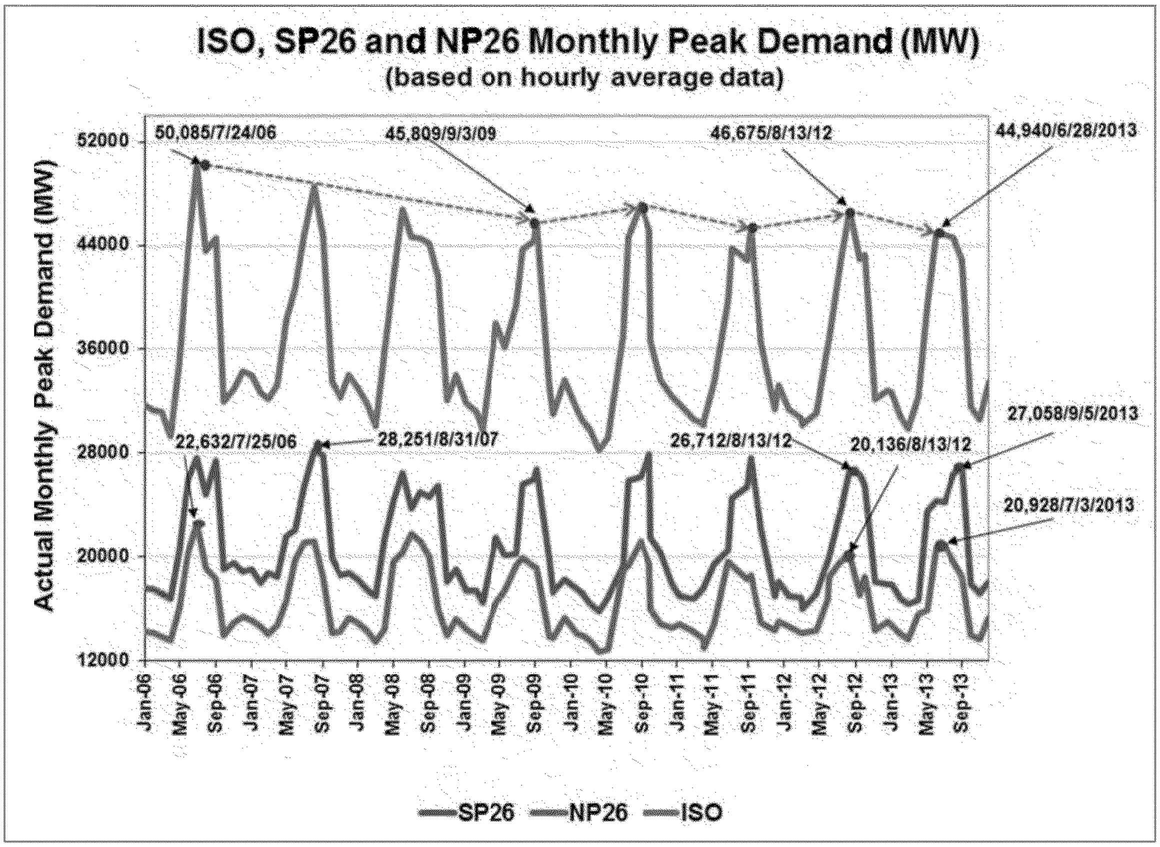


Figure 3 shows the ISO balancing authority system peak as well as peaks for Northern and Southern California. Starting in 2006, the summer ISO peak demand gradually declined to 2009, somewhat rollercoaster from 2009 to 2013.

Table 4 shows the difference between 2013 actual peak demands and 2013 1-in-2 peak demand forecasts. The ISO peak demand in 2013 was categorized as approximately the 20th percentile or 1-in-1.25 temperature event. The 20th percentile represents a point at which 20 percent of the probable outcomes will be equal to or less than this value. The weather normalized peak load for ISO in 2013 was 46,705 MW.

The actual peak demand in Southern California was 195 MW lower than the 1-in-2 forecast peak demand for SP26, The weather at the time of the SP26 peak demand was the 27th percentile or 1-in-1.38 temperature event. A combination of a mild weather pattern, demand response, and an actual economic growth slower than that forecasted by Moody's was the main contributor to the actual peak demands being lower than 1-in-2 forecast peak demands for ISO and SP26.

The actual peak demand in Northern California was 400 MW lower than 1-in-2 forecast peak demand for NP26. The weather at the time of the NP26 peak demand was the 62th percentile or 1-in-2.63 temperature event. This anomaly was the result of differences in non-weather parameters in the load forecast model, including but not limited to the difference between the realized economic growth in Northern California and the assumptions incorporated into the forecast. The downward impact of these variations from forecast more than offset the upward impact of higher than average temperatures.

Table 4

2013 ISO Actual Peak Demand vs. Forecasts

	1-in-2 Forecast (MW)	Actual (MW)	Difference from 1-in-2 Forecast (MW)	Difference from 1-in-2 Forecast (%)
ISO	47,413	44,941	-2,472	-5.2%
SP26	27,253	27,058	-195	-0.7%
NP26	21,328	20,928	-400	-1.9%

Generation

As of April 22, 2014, the net dependable capacity of the ISO balancing authority was 65,226 MW, including 32,157 MW in SP26 and 33,069 MW in NP26. The NDC is the maximum capacity of a unit during the most restrictive seasonal conditions less the units' capability used for station service or auxiliaries. It includes the capability of units that may be temporarily inoperable because of maintenance, forced outage, or other reasons, or only operable at less than full output. It excludes power required for plant operation and emergency power for unit startup and shutdown. The net dependable capacity of the ISO balancing authority is shown in *Appendix B 2014 ISO NDC and RPS by Fuel Type.*

Generation in the ISO balancing authority is primarily fueled by natural gas (60.8%), followed by 22.0% renewables portfolio standard (RPS) resources, 12.5% large hydro, 3.5% nuclear units and a small amount of oil and coal. Although SONGS units 2 and 3 totaling 2,246 MW were retired on June 7, 2013, they were excluded in 2013 summer resources and outages calculation. Contra Costa Units 6 and 7 totaling 674 MW were replaced on May 1, 2013 with 800 MW Marsh Landing Generation Station units 1 to 4. Huntington Beach units 3 and 4 were converted to synchronous condensers on December 7, 2012. Morro Bay Units 3 and 4 retired on February 5, 2014. The ISO used the California Public Utilities Commission methodology for determining the components of the renewables portfolio standard generation.[15] The conventional resources included natural gas, nuclear, oil and coal.

Renewables Generation

A total of 14,330 MW renewable commercial operation generations were composed of 41.5% wind, 31.1% solar, 11.0% geothermal, 8.9% small hydro, 4.8% biomass, and 2.9% biogas. Maximum wind generation reached 4,268 MW on June 23, 2013. Maximum solar generation reached 2,893 MW on December 26, 2013. Because California has relatively large share of natural gas generation, a potential shortage of natural gas could create reliability issues on the power grid. Greater fuel diversity through integration of renewable energy resources is helping to mitigate this risk.

Generation Outages

The average weekday generation outages in 2013 were lower than those in 2012, with the most significant contribution to the change coming from the retirement of the SONGS units 2 and 3. ISO average weekday generation outages from June 2013 to September 2013 were 5,104 MW lower than 8,220 MW in 2012. SP26 average weekday outages were 2,341 MW lower than 4,307 MW in 2012. NP26 average weekday outages were 2,178 MW lower than 3,913 MW in 2012.

Graphs in *Appendix C: 2011 – 2013 Summer Generation Outage Graphs* show the weekday hour-ending 16:00 forced and planned outage amounts during the summer peak days from June 15 through September 30 for the 2011, 2012, and 2013 (excluding holidays). The graphs do not include ambient and normal outages as these amounts are accounted for in the NQC listing, based on most likely summer peak weather conditions.

A forced outage is the outage where the equipment is unavailable for unexpected events such as the removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. A planned outage is the outage where the shutdown of a generating unit, transmission line, or other facility, is for inspection or maintenance, in accordance with an advance schedule. An ambient outage is a special type of outage where the cause is due to ambient conditions outside of the resource operator's control. The ambient conditions include exceeding air emission limits, lack of fuel, lack of water, low steam pressure, geomagnetic disturbance, earthquake, or catastrophe. Normal outage is the outage when the unit cannot response to a dispatch due to designed operations.

Imports

Figure 4 shows the 2013 ISO peak and the net interchange over the weekday summer peak load period. There are numerous factors that determine to the level of interchange

[15] Renewable Energy and RPS Eligibility; website: http://www.cpuc.ca.gov/PUC/energy/Renewables/FAQs/01REandRPSeligibility.htm

between the ISO and other balancing authorities at any given point in time (refer to the Imports section on page 20).

The imports at the 2014 summer peak for ISO and SP26 decreased in 2013. The ISO imports at the peak decreased from 9,199 MW in 2012 to 8,780 MW in 2013 and the SP26 imports at its peak decreased from 8,513 MW in 2012 to 8,306 MW in 2013. These decreases were due in part to higher in-state generation dispatch in Southern California in 2013 and low loads due to mild weather. However, the NP26 imports at its peak increased from 997 MW in 2012 to 2,331 MW in 2013. *(Appendix D: 2011 – 2013 Summer Imports Summary Graph)*

Figure 4

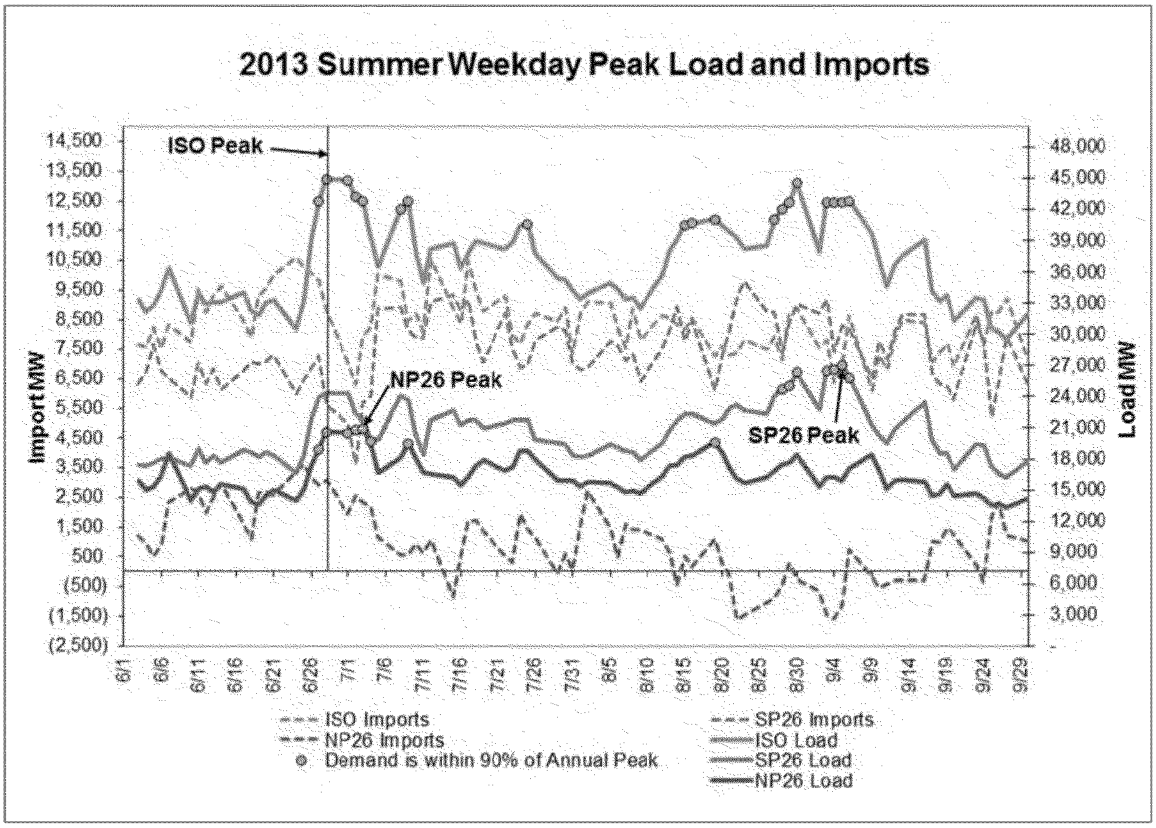


Figure 4 shows the amount of imports at ISO daily system peaks.

III. SUMMER 2014 ASSESSMENT

Generation

Total ISO generation NQC (before hydro derates) for the 2014 summer peak is estimated to be 53,950 MW, a 3,243 MW increase from June 1, 2013. This additional amount will help meet an expected 646 MW of load growth and offset the hydro derate for this summer. Each year, CPUC, the CEC and the ISO work together to publish an NQC list which describes the amount of capacity that can be counted from each resource to meet Resource Adequacy requirements in the CPUC's RA program. To account for the variable output of intermittent resources, the NQC calculation process uses a three-year rolling average of historical production data to determine the NQC for each wind, solar, or other non-dispatchable resource. The NQC for dispatchable resources depends on its availability and deliverability. The ISO determines the net qualifying capacity by testing and verification as outlined in the ISO tariff and the applicable business practice manual.

The largest available generation resource type is natural gas generation accounting for 68.7% and the second largest generation type is hydro accounting for 14.2%. Non-hydro renewables including geothermal, biogas, biomass, wind and solar units make up about 11.7%. With the retirement of both SONGS units nuclear generation accounts for 4.2% while coal and oil generation provide 1.2%. On-peak NQC by fuel type is shown in *Appendix E: 2013 ISO Summer On-Peak NQC Fuel Type.*

Generation Addition and Retirement

Table 5 shows that a total of 3,555 MW of NQC came on line in the ISO balancing authority from June 1, 2013 to April 22, 2014. This new NQC included 1,997 MW in SP26 and 1,558 MW in NP26, and 650 MW from Morro Bay Units 3 and 4 retiring on February 5, 2014. After April 22, 2014, 338 MW of additional net qualifying capacity generation is expected to come on line by June 1, 2014 as shown in *Table 6*, with 261 MW in SP26 and 77 MW in NP26. New generation with zero NQC are not listed in *Tables 5* and *6*.

Table 7 shows the total generation capacity changes within the ISO since June 1, 2013 and expected by June 1, 2014. A total of 3,243 MW of generation additions are expected to enter commercial operation for this summer, 2,258 MW in SP26 and 985 MW in NP26. This table was developed using the final NQC list that was used for the California Public Utilities Commission as part of its resource adequacy program for compliance year 2014, which the ISO posted to its website on March 13, 2014. Generators who chose not to participate in the NQC process were added using the ISO Master Control Area Generating Capability List, which is also posted on the ISO website.[16]

[16] *Master Control Area Generating Capability List* website : http://www.caiso.com/participate/Pages/Generation/Default.aspx

Table 5

New Generating Capacity (MW)
(Generation that achieved commercial operation from 6/1/ 2013 to 4/22/2014)

Resource ID	COD	NDC	NQC (est)	Fuel Type	Area
DEVERS_1_SOLAR1	01-Jun-13	12.0	8.2	SUN	SCE
DEVERS_1_SOLAR2	01-Jun-13	9.0	6.2	SUN	SCE
KANSAS_6_SOLAR	06-Jun-13	20.0	13.7	SUN	PGAE
COCOSB_6_SOLAR	12-Jun-13	1.5	1.0	SUN	PGAE
OLIVEP_1_SOLAR	22-Jun-13	20.0	13.7	SUN	PGAE
GATES_2_SOLAR	24-Jun-13	20.0	13.7	SUN	PGAE
GATES_2_WSOLAR	24-Jun-13	10.0	6.8	SUN	PGAE
ELSEGN_2_UN2021	29-Jun-13	263.7	263.7	NATURAL GAS	SCE
ELSEGN_2_UN1011	09-Jul-13	263.0	263.0	NATURAL GAS	SCE
DAVIS_1_SOLAR1	01-Jul-13	1.0	0.7	SUN	PGAE
GONZLS_6_UNIT	08-Jul-13	1.4	0.9	LANDFILL GAS	PGAE
PEABDY_2_LNDFIL	09-Jul-13	1.6	1.0	LANDFILL GAS	PGAE
SANLOB_1_LNDFIL	21-Jul-13	1.5	0.9	LANDFILL GAS	PGAE
OCTILO_5_WIND	29-Jul-13	265.0	50.5	WIND	SDGE
LECEF_1_UNITS	31-Jul-13	315.0	315.0	NATURAL GAS	PGAE
DAVIS_1_SOLAR2	05-Aug-13	1.0	0.7	SUN	PGAE
RUSCTY_2_UNITS	08-Aug-13	625.0	625.0	NATURAL GAS	PGAE
WAUKNA_1_SOLAR	14-Aug-13	20.0	13.7	SUN	PGAE
VACADX_1_NAS	06-Sep-13	1.9	1.9	BATTERY	PGAE
TOPAZ_2_SOLAR	09-Sep-13	237.0	162.1	SUN	PGAE
VISTA_2_FCELL	13-Sep-13	1.4	0.9	AGRICULTURAL WASTE	SCE
GUERNS_6_SOLAR	18-Sep-13	20.0	13.7	SUN	PGAE
CSLR4S_2_SOLAR	11-Oct-13	130.0	88.9	SUN	SDGE
CNTNLA_2_SOLAR1	16-Oct-13	51.5	35.2	SUN	SDGE
CPVERD_2_SOLAR	22-Oct-13	150.0	102.6	SUN	SDGE
SOLAR PROJECT	10/22/2013 (COM)	219.7	150.2	SUN	SCE
CAVLSR_2_RSOLAR	01-Nov-13	210.0	143.6	SUN	PGAE
ARLVAL_5_SOLAR	05-Nov-13	127.0	86.8	SUN	SDGE
GLDTWN_6_SOLAR	18-Nov-13	5.0	3.4	SUN	SCE
GENESI_2_STG	27-Nov-13	250.0	171.0	SUN	PGAE
VICTOR_1_SOLAR1	06-Dec-13	17.5	12.0	SUN	SCE
GLDTWN_6_COLUM3	10-Dec-13	10.0	6.8	SUN	SCE
ETIWND_2_CHMPNE	20-Dec-13	1.0	0.7	SUN	SCE
CHINO_2_JURUPA	20-Dec-13	1.5	1.0	SUN	SCE
CONTRL_1_CASAD1	20-Dec-13	10.0	7.0	GEOTHERMAL	PGAE
CHINO_2_SASOLR	20-Dec-13	1.5	1.0	SUN	SCE
DEVERS_1_SOLAR	24-Dec-13	18.5	12.7	SUN	SCE
RSMSLR_6_SOLAR1	20-Dec-13	20.0	13.7	SUN	SCE
RSMSLR_6_SOLAR2	20-Dec-13	20.0	13.7	SUN	SCE
PEORIA_1_SOLAR	30-Dec-13	1.5	1.0	SUN	PGAE
KNGBRG_1_KBSLR1	30-Dec-13	1.5	1.0	SUN	PGAE
KNGBRG_1_KBSLR2	30-Dec-13	1.5	1.0	SUN	PGAE
IVANPA_1_UNIT1	30-Dec-13	126.0	86.2	SUN	SCE
IVANPA_1_UNIT2	30-Dec-13	133.0	90.9	SUN	SCE
IVANPA_1_UNIT3	30-Dec-13	133.0	90.9	SUN	SCE
VLCNTR_6_VCSLR1	30-Dec-13	2.5	1.7	SUN	SDGE
VLCNTR_6_VCSLR2	30-Dec-13	5.0	3.4	SUN	SDGE
CRELMN_6_RAMON1	30-Dec-13	2.0	1.4	SUN	SDGE
CRELMN_6_RAMON2	31-Dec-13	5.0	3.4	SUN	SDGE
MSOLAR_2_SOLAR1	01-Jan-14	165.0	112.8	SUN	SCE
ESCNDO_6_PL1X2	23-Jan-14	49.5	49.5	NATURAL GAS	SDGE
LOCKFD_1_BEARCK	05-Feb-14	1.5	1.0	SUN	PGAE
COGNAT_1_UNIT	12-Feb-14	49.5	30.2	BIOMASS	PGAE
JAYNE_6_WLSLR	18-Feb-14	18.0	12.3	SUN	PGAE
IVSLRP_2_SOLAR1	04-Mar-14	200.0	136.8	SUN	SDGE
PIT1_6_FRIVRA	05-Mar-14	1.5	1.0	SUN	PGAE
MCARTH_6_FRIVRB	05-Mar-14	1.5	1.0	SUN	PGAE
TMPLTN_2_SOLAR	06-Mar-14	1.5	1.0	SUN	PGAE
OLDRIV_6_BIOGAS	10-Mar-14	2.0	1.2	BIOMASS	PGAE
RIVRBK_1_LNDFIL	11-Mar-14	1.0	0.6	LANDFILL GAS	PGAE
WIND PROJECT	3/13/2014 (COM)	138.0	26.3	Wind	SCE
OTAY_6_LNDFL5	14-Mar-14	1.5	0.9	Land Fill Gas	SDGE
OTAY_6_LNDFL6	14-Mar-14	1.5	0.9	Land Fill Gas	SDGE
LOCKFD_1_KSOLAR	14-Mar-14	1.0	0.7	SUN	PGAE
WIND PROJECT	3/17/2014 (COM)	90.0	17.1	Wind	SCE
SOLAR PROJECT	4/17/2014 (COM)	72.0	49.2	SUN	SCE
SOLAR PROJECT	4/17/2014 (COM)	103.5	70.8	SUN	SCE
SOLAR PROJECT	4/18/2014 (COM)	195.3	133.6	SUN	SCE
Total		4,859	3,555	ISO	
		3,010	1,997	SP26	
		1,849	1,558	NP26	

Note: COM means commercial operations for markets

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Table 6

High Probability Generation Additions Expected (MW) from 4/23/2014 to 6/1/2014					
Project Name	**Project Type**	**Estimated COD**	**NDC**	**NQC (est)**	**PTO**
Solar Project	New	4/23/2014	1.5	1.0	SCE
Solar Project	New	4/23/2014	20.0	13.7	PG&E
Solar Project	New	4/27/2014	1.5	1.0	PG&E
Solar Project	New	4/30/2014	2.0	1.4	SCE
Solar Project	New	4/30/2014	2.0	1.4	SCE
Solar Project	New	4/30/2014	5.0	3.4	SCE
Solar Project	New	before 6/1/2014	20.0	13.7	PG&E
Solar Project	New	before 6/1/2014	20.0	13.7	PG&E
Solar Project	New	before 6/1/2014	6.5	4.4	SDG&E
Wind Project	New	before 6/1/2014	4.2	0.8	SCE
Solar Project	New	before 6/1/2014	1.5	1.0	PG&E
Solar Project	New	before 6/1/2014	1.3	0.9	PG&E
Solar Project	New	before 6/1/2014	25.0	17.1	PG&E
Land Fill Gas Project	New	before 6/1/2014	0.8	0.5	PG&E
Land Fill Gas Project	New	before 6/1/2014	20.0	12.2	SCE
Solar Project	New	before 6/1/2014	1.3	0.9	PG&E
Biomass Project	New	before 6/1/2014	3.0	1.8	PG&E
Natural Gas Project	New	before 6/1/2014	4.3	4.3	PG&E
Natural Gas Project	New	before 6/1/2014	4.2	4.2	PG&E
Natural Gas Project	New	before 6/1/2014	4.3	4.3	PG&E
Solar Project	New	before 6/1/2014	1.5	1.0	SCE
Solar Project	New	before 6/1/2014	1.5	1.0	SCE
Solar Project	New	before 6/1/2014	1.5	1.0	SCE
Solar Project	New	before 6/1/2014	1.5	1.0	SCE
Land Fill Gas Project	New	before 6/1/2014	20.0	12.2	SCE
Land Fill Gas Project	New	before 6/1/2014	20.0	12.2	SCE
Land Fill Gas Project	New	before 6/1/2014	20.0	12.2	SCE
Land Fill Gas Project	New	before 6/1/2014	20.0	12.2	SCE
Land Fill Gas Project	New	before 6/1/2014	20.0	12.2	SCE
Natural Gas Project	Conversion	before 6/1/2014	170.7	170.7	SCE
Total			425	338	ISO
			318	261	SP26
			107	77	NP26

Table 7

Total Expected Generation change (MW) from June 1, 2013 to June 1, 2014						
	from 6/1/2013 to 4/22/2014	from 6/1/2013 to 4/22/2014	As of 4/22/ 2014	from 4/23/2014 to 6/1/2014	for 2014 summer	for 2014 summer
	Additions COD	Retirements	Existing	High Probability Additions	Total Expected	Total Expected Change
ISO	3,555	(650)	53,612	338	53,950	3,243
SP26	1,997	0	26,178	261	26,439	2,258
NP26	1,558	(650)	27,434	77	27,511	985

This assessment uses all capacity available within the ISO balancing authority regardless of contractual arrangements to evaluate resource adequacy in order to understand how the system will respond under contingencies. Although some resources may not receive contracts under the resource adequacy program, and may contract with entities outside the ISO for scheduled short-term exports, these resources are still considered available to the ISO.

The NQC values for wind and solar are determined and annually adjusted based on actual output during peak hours over a three-year period. If the ISO balancing authority experiences extreme weather conditions beyond what is considered by the NQC calculation process, it is possible that not all of the capacity accounted for will be available because the unit ratings of combustion turbines and some other resources are impacted by high ambient temperatures.

Generation Unavailability

The estimated 1-in-2 generation outages during the 2014 summer peak demand periods for the ISO, SP26 and NP26 are 5,030 MW, 2,105 MW and 2,921 MW, respectively. The estimated 1-in-10 generation outages for the ISO, SP26 and NP26 are 6,478 MW, 3,406 MW and 4,126 MW, respectively (*Table 8)*. The last three years of generation outages during the peak demand period were used to develop a range of outages for the probabilistic analysis and to determine the 1-in-2 and 1-in-10 outage levels for the deterministic analysis.

Table 8

Generation Outages for Summer 2014 (MW)			
	ISO	SP26	NP26
1-in-2	5,030	2,105	2,921
1-in-10	6,478	3,406	4,126