**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA**

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

# OPENING BRIEF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION


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**TRACK 4 OPENING BRIEF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION**

# I. INTRODUCTION

In the September 16, 2013 Assigned Commissioner/Administrative Law Judge's (ACR/ALJ's) Ruling regarding Track 4 scheduling, the Commission found it necessary and useful to move forward on the schedule established in the May 21, 2013, Revised Scoping Ruling (Revised Scoping Ruling) to provide direction to Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) regarding immediate procurement authorization. The Commission specifically noted that while the determination of resources needed over the long-term to replace SONGS should take into account the results of the California Independent System Operator Corporation's (ISO's) 2013/2014 transmission planning studies, there is an urgency to moving forward with some procurement in light of the long lead times needed to site and construct new resources.

Accordingly, the parties submitted testimony responding to the ISO's need assessment and the Commission conducted an evidentiary hearing from October 28-November 1, 2013. At the close of hearings, the ALJ established November 25, 2013, as the date upon which Track 4 opening briefs would be due, and December 16, 2013 as the date for Track 4 reply briefs.

Consistent with that schedule, the California Independent System Operator Corporation (ISO) hereby submits its Track 4 opening brief.

## II. THIS PROCEEDING IS AN URGENT FIRST STEP TOWARD MEETING THE COMPREHENSIVE RESOURCE NEEDS CREATED BY THE SONGS CLOSURE AND ONCE THROUGH COOLING REQUIREMENTS WITH PREFERRED RESOURCES, TRANSMISSION SOLUTIONS AND CONVENTIONAL RESOURCES.

### A. The Track 4 Decision Will Be an Important First Step Towards a Long-Term Reliability Solution.

This 2012/2013 biennial long term procurement proceeding has dealt with resource and procurement issues not usually presented for resolution in a typical procurement cycle. In Track 1 the Commission considered the long term local area resource needs of the LA Basin/Moorpark-Ventura local capacity issues in light of the once-through cooling (OTC) environmental requirements imposed by the State Water Resources Control Board on coastal and estuarine generating units. At approximately the same time, the Commission considered in A.11-05-023 the local area resource needs in the San Diego area in light of the OTC requirements. Both the Track 1 resource procurement decision (D.13-02-015) and the decision in A.11-05-023 (D.13-03-029) were based on ISO studies that assumed the continued availability of the San Onofre Nuclear Generating Station (SONGS), despite a prolonged outage of that unit. Given that study assumption, Track 4 was established to consider the need for additional resources in the combined LA Basin/San Diego local capacity areas (SONGS Study Area) assuming that SONGS was not online, an eventuality that came to pass on June 7, 2013. Thus, in a two year time span the Commission is being asked to make local procurement decisions that are needed to replace much of the existing resource fleet in southern California. Overlaid onto this dramatic shift in existing resources are the state's aggressive renewable portfolio goals and the role of preferred resources in meeting future generation needs.

### B. The evidentiary record supports procurement of a "no regrets" level of additional resources.

In this Track 4, the Commission must take the first step down the path in developing a mix of resources by establishing the residual resource needs and authorizing interim additional procurement to address those needs in the SONGS study area. With the differences of opinion that have expressed on that topic, this might seem like a daunting task. However, the evidentiary records developed in Track 1 and A.11-05-023, as well as in the Track 4 hearings just concluded, provide all of the necessary tools and information needed to make a decision about the need for additional resources in light of the SONGS retirement and the potential retirement of the OTC units. Indeed, the ISO encourages the Commission to build on the decisions made in these prior proceedings and to move forward with authorizing an interim amount of additional "no-regrets" resource procurement at this time.

### C. Transmission Solutions and the Updated Load Forecast Should be Considered in Determining Additional Procurement Needs as Expeditiously as Possible.

Although the ISO supports an interim decision that will permit SCE and SDG&E to move forward with a finite amount of resource procurement, there is still work to be done. The ISO will release its draft transmission solution recommendations in late January 2014, with Board of Governor approval in March 2014. These results should be considered in the upcoming LTPP proceeding, with a decision about additional procurement needs issued in 2014 so that SDG&E and SCE can undertake all-source procurement initiatives as quickly as possible in advance of upcoming OTC retirement dates.

### D. Preferred Resource Development Must Be Accelerated and Monitored.

The important of preferred resources in meeting resource needs in southern California was underscored in the Preliminary Reliability Plan for LA Basin and San Diego, an effort by the ISO, CEC and CPUC staff representatives to consider the scope of issues and a path forward to address reliability needs in light of the SONGS closure.[1] The Plan recommends a mix of resources, with a goal that 50% of these would be preferred resources along with transmission upgrades and conventional generation. These preferred resources are *in addition* to the amounts that are already being counted on to meet capacity needs. Monitoring is critical given the size of this combined level of preferred resources, especially given the geographic limitations and performance characteristics necessary to meet operational requirements.

The need for monitoring does not minimize the importance work that is already underway to address these needs. In Track 1 the ISO expressed its intent to work with the Commission and stakeholders to identify preferred resource characteristics needed to meet local capacity needs. The ISO has made good on its intentions, as Mr. Millar described in his rebuttal testimony. In the 2013/2014 transmission planning process the ISO introduced a preliminary methodology for assessing demand response (DR) characteristics in order to consider whether DR can serve as an alternative to transmission or conventional generation resources in capacity-constrained local areas.[2] The ISO is also proposing to launch a preferred resource voluntary

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[1] *Id.*, p. 6; the Preliminary Plan is an attachment to ORA-5.

[2] ISO-7, p.4; see also http://www.caiso.com/Documents/Paper-Non-ConventionalAlternatives-2013-2014TransmissionPlanningProcess.pdf

auction initiative that is targeting procurement of demand response resources to be available to meet local resource adequacy needs in 2015 and beyond.[3]

In addition, the Commission is working on demand response and energy efficiency initiatives in other dockets that help to shape the participation of these preferred resources in achieving load reduction impacts and supply side resource availability to meet reliability needs.

However, it is vital that the development of these resources be carefully tracked and monitored, to ensure that they will be available when needed and before the dates that conventional resources will be taken off-line. Otherwise, it will become necessary to open a regulatory proceeding at the State Water Resources Control Board to extend the life of inefficient Korean War era once-through cooled power plants, with associated air quality, sea life entrainment, and efficiency impacts. The ISO intends to continue to work diligently with the Commission, the CEC and the Water Board to avoid such circumstances, but action on many levels must take place very quickly.

## III. BACKGROUND AND OVERVIEW OF STUDY PARAMETERS

The framework for this Track 4 decision was established in the Revised Scoping Ruling, with one modification addressed in the September 16 AC/ALJ Ruling. Following a May 10, 2013 prehearing conference, the Revised Scoping Ruling revised the original May 17, 2012 Scoping Ruling and added the fourth track to address the impact of a prolonged SONGS outage on local resource needs. Noting that the ISO was running Track 2 *system* studies based on the standardized planning assumptions set forth in the June 27, 2012 Assigned Commissioner's

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3 http://www.caiso.com/Documents/NewStakeholderInitiativeVoluntaryPreferredResourceAuctionNov25_2013.htm

Ruling, the Revised Scoping Ruling set forth, in Attachment A, the planning assumptions to be used by the ISO in Track 4.

Attachment A contained very specific study parameters that the ISO followed in conducting its analysis, and these were discussed in detail in Robert Sparks' initial testimony.[4] These study parameters included:

- The ISO would model three separate cases: 2022 without SONGS, 2022 with SONGS and 2018 without SONGS.
- The LA Basin and San Diego local capacity areas would be combined into a SONGS study area for the purposes of the studies.
- The modeling assumptions are consistent with the 2012 LTPP Scenarios and Assumptions, the Track 1 decision (D.13-02-015) and the San Diego Gas & Electric (SDG&E) Power Purchase Tolling Agreement (PPTA) decision (D.13-03-029).
- The Attachment A Summary Table Input Assumptions addressed load, incremental Energy Efficiency (EE), incremental Demand Response (DR), incremental combined heat and power (CHP), incremental installed PV capacity, the applicable Renewables Portfolio Standard (RPS) portfolio, resource additions and retirements and assumed transmission additions.

The Revised Scoping Memo established a schedule for testimony, reply testimony and an evidentiary hearing, if needed. Noting that SDG&E and Southern California Edison (SCE) were also conducting studies, the ruling set forth dates for the ISO to submit study results, followed by the study results presented by other parties.

[4] ISO-1.

The ISO submitted opening testimony on August 5, 2013, consistent with the schedule. Testimony containing additional study results was submitted on August 26, 2013, by SDG&E, SCE and the City of Redondo Beach (Redondo Beach).[5] Following this testimony submission, the Commission held another prehearing conference on September 4, 2013, to consider possible schedule adjustments in light of the ISO's recommendation to defer a procurement decision until transmission studies had been completed. Parties at the prehearing conference also discussed the status of Track 2 studies and the SDG&E and SCE requests for expeditious procurement authorization in Track 4. In addition, at the prehearing conference ALJ Gamson outlined a number of additional issues that the parties could include in testimony.

On September 16, 2013, the Assigned Commissioner issued a revised Track 2 and Track 4 schedule (September 16 ACR). As requested by the ISO, Track 2 as part of the current LTPP was canceled and system procurement issues deferred to the upcoming 2014 LTPP. However, the revised Track 4 schedule continued to focus on a decision in early 2014 that would not include the results of the ISO's transmission planning studies.[6] The September 16 ACR determined that the additional issues outlined by the ALJ at the prehearing conference were policy considerations that did not involve disputed facts and could be addressed in comments that would be due according to the revised schedule contained in the ACR.

Nineteen parties submitted opening testimony on September 30, 2013, responding to the ISO, SCE, SDG&E and Redondo Beach study results.[7] On October 14, 2013, the ISO, SCE,

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[5] SCE-1 and 1a; SDG&E 1 and 3; RB-1a.

[6] September 16 ACR, page 3.

[7] These parties include California Environmental Justice Alliance (CEJA), Sierra Club, AES Southland, Natural Resources Defense Council (NRDC), NRG, Clean Coalition, California Energy Storage Association (CESA), The Utility Reform Network (TURN), Office of Ratepayer Advocates (ORA), Protect Our Communities Foundation (POC), Pacific Gas & Electric (PG&E), Direct Access Customer Coalition/Alliance for Retail Energy Markets

SDG&E and Redondo Beach submitted rebuttal testimony, along with CEJA, Sierra Club, NRDC, TURN, ORA, PG&E and WPTF. Evidentiary hearings were held from October 28-November 1, 2013 according to the established schedule.

The testimony and rebuttal testimony ran the entire spectrum from support for the ISO/SCE/SDG&E's study results and procurement recommendations to disagreement with the conclusion that any incremental resources whatsoever are needed. In the middle of the spectrum were those parties who agreed with the need for additional resource procurement but that asserted that these needs could be met in a variety of ways[8], those who advocated that the Commission should take into account the ISO's transmission planning studies before making procurement decisions,[9] and those who supported particular resource technologies and procurement strategies to fill resource needs.[10] DACC/AReM, and to a certain extent PG&E, addressed cost allocation issues.

In rebuttal testimony, the ISO responded to parties who took issue with its study methodology and assumptions, as well as providing additional information as the ISO's grid planning standards, NERC/WECC reliability standards and ongoing efforts to promote the development of preferred resources to meet local resource needs. With this brief and the upcoming reply brief, the ISO will summarize its testimony and respond to some of the additional issues raised by the parties.

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(DACC/AReM), Western Power Trading Forum (WPTF), Environmental Defense Fund (EDF), Center for Energy Efficiency and Renewable Technologies (CEERT), EnerNOC, Independent Energy Producers (IEP), Vote Solar Initiative (VSI) and Wellhead.

[8] See, e.g. ORA and TURN

[9] See, *e.g.* CEERT, ORA.

[10] See, e.g. AES Southland, NRG, Wellhead, CESA and WPTF.

## IV. THE ISO'S TRACK 4 STUDY RESULTS AND STUDY METHODOLOGY IDENTIFY RESOURCE NEEDS.

### A. The ISO's Track 4 Analysis Reveals Substantial Local Resource Needs in the SONGS Study Area in Starting in 2018.

In opening testimony, ISO witness Robert Sparks described in detail how the ISO modeled the Attachment A assumptions and then depicted the ISO's study results in several comparison tables. He also explained the differences between the ISO's OTC studies that were used to determine local resource needs in D.13-02-015 and D.13-03-029.

At the beginning of his opening testimony, Mr. Sparks provided information about how the ISO modeled: 1) the CEC 1-in-10 peak load forecast for 2018 and 2022; 2) the low level of incremental EE from the CEC forecast, scaled up to account for distribution losses; 3) a total of 189 MW of first post-contingency DR (scaled up for distribution losses) with the remaining 997 MW utilized on a second post-contingency basis; 4) system-connected and small photovoltaic distributed generation (DG) (specifically system-connected DG which was assumed to be in effective locations); 5) transmission projects approved in the 2012/2013 Transmission Plan; 6) new generation projects completed in 2013 and the Escondido Repowering Project; 7) the OTC and other generation retirement assumptions described in Attachment A; and 8) the Commercial Interest RPS portfolio, including the list of renewable projects for 2018 and 2022 provided by the CPUC staff.[11] Details about each of these assumptions were provided in Tables 1-7. The study results for the 2018 and 2002 without SONGS scenarios, as well as the 2022 with SONGS scenario, were captured in Tables 9-13.[12]

[11] ISO-1, pp.3:13-13:17.

[12] Mr. Sparks' testimony inadvertently did not include a Table 8.

Table 13 in Mr. Sparks testimony identifies the residual resource needs in 2022 without SONGS:[13]

**Table 13 – Residual Resource Needs in 2022 Without SONGS**

| Scenario | Track 1 Decisions (MW) | | Track 4 Studies (2022) (SONGS Study Area = LA Basin + San Diego) (MW) | | | | Residual Resource Needs (Total Track 4 – Maximum Track 1) for SONGS Study Area (MW) |
|---|---|---|---|---|---|---|---|
| | LA Basin | San Diego | DR Assumptions Modeled for Studies*** | Inc. EE Assumptions Modeled for the Studies | System-Connected DGs (Commercial Interest) | Identified Resource Needs Without SONGS | |
| 80%/20% (LA/SD) Total Resource Development Scenario | 1,800* | 308** | 198 | 983 | 1,016 (Installed)<br>457 (NQC) | 4,642 | 4,642 – 1,800 - 308 = 2,534<br>Breakdown:<br>LA Basin (1,922)<br>San Diego (612) |
| Two-thirds/One-Thirds(LA/SD) Total Resource Development Scenario | 1,800* | 308** | 198 | 983 | 1,016 (Installed)<br>457 (NQC) | 4,507 | 4,507 – 1,800 – 308 = 2,399<br>Breakdown:<br>LA Basin (1,222)<br>San Diego (1,177) |

[13] ISO-1, page 26.

Notes:

*Maximum authorized procurement resources in the LA Basin, including preferred resources

**Includes 10 MW of net increase for Escondido

*** Post first contingency values (for use in preparation for second contingency)

The table contains the results for two 2022 without SONGS resource development study scenarios described by Mr. Sparks. The first resource development scenario assumed an 80%/20% resource split between the LA Basin and San Diego local areas, resulting in total resource needs of 4642 MW. The second resource development scenario evaluated a two-third/one-third split between the two areas, and this resulted in a 4507 MW total resource need. As Mr. Sparks explained, the ISO assumed 565 MW of conventional gas-fired generation added to the San Onofre switchyard and found that every 1 MW resulted in a 1.24 MW reduction in the LA Basin local needs. However, the feasibility of construction in these areas is not known.[14]

The first column of Table 13 contains the procurement amounts authorized in D.13-02-015 (Track 1) and D.13-03-029 (SDG&E PPTA). The second column lists the DR incremental energy efficiency (EE) and system-connected DG distributed generation modeled in the study and identified in the previous tables, as well as the total resource needs under each resource development scenario. The final column contains the mathematical calculation used to determine the residual resource needs in each scenario (total resource need- resource procurement previously authorized). For the first resource development scenario, the residual resource need is 1922 MW in the LA Basin and 612 MW in San Diego. Assuming the two-third/one-third resource split, the residual resource needs are 1222 MW in the LA Basin and 1177 in San Diego. The ISO notes that these residual local area needs are consistent with the

[14] ISO-1, pp. 23-24.

"without SONGS" analysis conducted in the 2012/2013 transmission planning process, which formed the basis for the recommendations contained in the Preliminary Reliability Plan for LA Basin and San Diego.[15] In the Track 4 final order, the Commission should adopt the ISO's study results as indicative of the residual resource needs for the LA and San Diego local areas.

### B. The ISO Correctly Modeled the Input Assumptions Described in the Revised Scoping Ruling.

Although numerous parties challenged the ISO's study methodology (see Section II.C below), only CEJA witness Julia May took issue with the way in which the ISO actually modeled the input assumptions. Starting at page 14 of her testimony,[16] Ms. May opines that the ISO "left out" preferred resource assumptions and other resources that could fill the incremental need, and that the ISO also incorrectly calculated transmission loss avoidance provided by distributed resources. However, these assertions are incorrect, as Mr. Sparks explained in his rebuttal testimony and during cross-examination.

Ms. May first states that the ISO incorrectly did not take into account 997 MW of demand response that she claims were to be used "to reduce the need for N-1-1 contingencies." She goes on cite the Revised Scoping Ruling Attachment A instructions as to how the ISO should consider the 997 MW for modeling purposes, and then apparently becomes confused by Mr. Sparks' use of the phrase "post second contingency" in his opening testimony.[17] Mr. Sparks addressed this confusion in his rebuttal testimony by explaining exactly what Attachment A instructed the ISO to do with the various types of demand response identified in the previous

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[15] See ISO-7, pp. 6-7; ORA-5

[16] CEJA-1, pp. 14-18.

[17] CEJA-1, pp. 14. "The CPUC's instructions in Attachment A direct that these resources be utilized to address the second contingency (Category C)- not 'post second contingency'…

decisions. As he noted, the Commission (at page 5 of Attachment A) stated that 173 MW of fast acting demand response in LA and 16 MW in San Diego should be assumed to be used after the first contingency (under N-1-1, the first transmission line outage), during which time the ISO has 30 minutes to readjust the system in preparation for the second overlapping contingency according to NERC reliability standard TPL-003.[18] The instructions also identified locations in the Orange County and San Diego areas where this fast demand response is most effective. The remaining 997 MW of demand response, which currently does not meet the specifications required to address the first contingency, will nonetheless be available in response to the second overlapping transmission line outage to mitigate this condition and avoid help to avoid involuntary load shedding.[19] The ISO's modeling is precisely in line with the language of the Attachment A instructions, which state that:

> To be consistent with the 2012 Load Impact Report, the remaining amount of LA Basin DR forecasted in the report shall be accounted for as a "Second Contingency" resource, i.e. a resource that is available to prepare for subsequent contingencies.[20]

Although this language does not use the phrase "extreme contingency," clearly the Commission acknowledged that the 997 MW of additional demand response would be available after the second overlapping contingency, which is a Category D event and for which involuntary load shedding would be permissible.

Notably, Ms. May does not provide any explanation or justification as to how the 997 MW of additional demand response could actually be used to addressed the first transmission line outage in the 30 minute time interval (including customer notification) in which the ISO

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[18] See Attachment A, footnote 11.

[19] ISO-1, p. 29.

[20] Attachment A, p. 5.

must readjust the system. Rather, she simply comes to the sweeping conclusion that 997 MW should be deducted from the residual local need calculation, without further justification as to how these resources could be used to meet local needs. While the ISO, the CPUC and other parties are working very hard on how to use demand response resources for local capacity needs, the interim approach adopted by the Commission with respect to Track 4 demand response is reasonable and should not be adjusted based on Ms. May's insubstantial testimony.

Similarly, Ms. May takes issue with the ISO's interpretation of the instructions to model customer-side distributed generation to address the second contingency, again apparently based on a misunderstanding of the ISO's opening testimony. In Mr. Sparks' opening testimony, he explained that, consistent with the Attachment A instructions, an incremental 1300 MW of installed customer-side distributed generation was assumed to be located in the ISO balancing authority area, which, when scaled down to the LA Basin and San Diego areas, becomes 477 MW and 616 MW (or 216 and 278 MW of production at peak load conditions). Because the location of this distributed generation is difficult to determine, the Commission instructed the ISO to consider these resources to be available to address the second contingency, similar to the 997 MW of demand response.[21] In rebuttal testimony Mr. Sparks testified that this amount of distributed generation could be available to the ISO to avoid activating the special protection scheme (SPS) that would trigger involuntary load shedding after the second contingency.[22]

Ms. May criticizes the ISO's explanation that these small PV resources were reflected "to a certain extent" in the Track 4 modeling,[23] but once again provides no sound basis for treating

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[21] ISO-1, p. 8. See also Attachment A, p. 10.

[22] ISO-2, pp. 18-19.

[23] CEJA-1, p. 15.

them differently. Specifically, she does not address the difficulty in determining customer locations for these resources which was the primary reason that they were recognized as second contingency resources. Ms. May's recommendation that these resource amounts be deducted from the residual local capacity needs should not be adopted.

Mr. Sparks also addressed Ms. May's inaccurate conclusion that the ISO failed to model the 50 MW of energy storage that SCE was directed to procure in D.13-02-015. Her testimony was apparently based on confusion caused by an ISO data request response which correctly stated that because there was no specific locational information available for the 50 MW, the ISO modeled only the 40 MW of Lake Hodges pumped storage. However, as Mr. Sparks explained, the 50 MW was included in the 1800 MW authorization that the ISO deducted from the total local needs to arrive at residual needs, and therefore the ISO study results do account for the 50 MW of energy storage that SCE will procure.[24]

Finally, Ms. May testified that the ISO should have included 188 MW of capacity provided by the Cabrillo peakers in San Diego, based on Mr. Powers' testimony in A.11-05-023 that SDG&E "is opting not to renew the lease with the third party owner of the turbines."[25] However, this suggestion is inconsistent with the Attachment A instructions, which assumed the retirement of 238 MW of non-OTC generation, including the Cabrillo peakers.[26] Other than citing Mr. Powers' testimony on this issue- which was not adopted in D.13-03-029 on this point. Ms. May has provided no credible reason to change this assumption.

### C. The Commission Should Not Lower the Level of Reliablity in Southern Orange County and San Diego by Adopting Adjustments to the ISO's Study

[24] ISO-2, p. 19.

[25] CEJA-1, pp. 19-21.

[26] ISO-2, p. 19.

**Methodology for the Purposes of Determining Residual Local Capacity Needs.**

Numerous parties took the position that the residual local capacity needs identified in the ISO opening testimony are too high because the ISO's study methodology is "too conservative" and based on transmission planning criteria that "go beyond" NERC or WECC reliability standards. Indeed, the ISO's study methodology became the most highly contentious issue in the Track 4 proceeding. However, the ISO's local capacity area planning standards and study parameters are well known to the Commission and were heavily litigated in A.11-05-023. The testimony presented in Track 4 plow furrowed ground and do not provide the Commission with any new information upon which a decision should be made that is contrary to the decisions reached in other proceedings.

1. Loading Shedding is not a Prudent Mitigation Solution for the N-1-1 Contingency in Densely Populated Urban Areas such as San Diego.

In conducting the Track 4 studies, the ISO used the same local capacity area study methodology employed for the OTC studies that formed the basis of the procurement decisions in Track 1 and A.11-05-023. As Mr. Sparks explained in his rebuttal testimony, the ISO's local capacity study methodology was litigated in both proceedings and approved without change.[27] In A.11-05-023, the ISO addressed the same concerns about mitigation solutions and load shedding for the San Diego N-1-1 critical contingency- the overlapping outages of the Southwest Power Link (SWPL) and Sunrise Powerlink transmission lines- and the ISO addressed these issues in testimony and briefs. The concerns were raised again in the recent SDG&E application for approval of the Pio Pico PPTA, and the ISO submitted testimony in that proceeding (A.13-

[27] ISO-2, pp. 2-3.

06-015) responding to arguments raised by Sierra Club, CEJA and POC. The ISO's testimony in A.13-06-015 was attached to Mr. Sparks' rebuttal testimony in Track 4 as ISO-3.

In essence, the controversy focuses on whether the overlapping outage of the SWPL (Eco-Miguel) 500 kV transmission line, followed by an outage of the Sunrise (Imperial Valley-Suncrest) 500 kV transmission line (an N-1-1 Category C contingency) should be addressed by load shedding or by other mitigation solutions such as additional local area resources or transmission upgrades. Consistent with the ISO's study methodology, as explained in testimony in A.11-05-023, in its Track 4 studies the ISO did not recommend load shedding as a long-term planning mitigation solution for this contingency. As Mr. Sparks explained, it is the ISO's position that load shedding in the highly urbanized San Diego area should not be used as a transmission planning tool. This is due to the significant amount of load that would be subject to load shedding, the sensitivity of urban loads to large blocks of load shedding, the complexity of operating arrangements in the area, and the proximity of particular transmission lines.[28]

In particular, the lines in question have a high exposure to outages, including a one-in-13 year fire risk and the probability of a simultaneous outage of the two lines (where four to eight miles apart) trends towards one in 21 years.[29] Mr. Sparks also testified that SDG&E, CFE and IID all have major transmission tie-lines emanating from the Imperial Valley substation, making the substation critical to the reliability of the system and vulnerable to human error. With the SONGS outage, system dependence on this substation has increased.

To be sure, NERC reliability standard TPL-003 permits load shedding in response to Category C contingencies, but does not *require* the ISO, as the Planning Coordinator, to approve

[28] ISO-3, p. 7.

[29] ISO-2, pp. 5-6.

automatic load shedding under all circumstances. For example, the ISO has load shedding schemes on the sub-transmission system or for extreme Category D contingencies.[30] Mr. Sparks testified, during re-direct examination, specifically that there are 34 load dropping special protection schemes (SPS) on the ISO grid.[31] Eighteen are on the sub-transmission (less than 200kV) system, and these drop small amounts of load in low density population areas. Four of the 34 drop pump load, and seven respond to extreme contingencies (Category D). Three SPS are on major paths where there are actually alternative transmission paths with alternative resources.

For large urban areas, the ISO's historic practice has been, as a last resort, to rely on load shedding as an interim measure only until the permanent solution can be put in place.[32] Mr. Sparks described the interim load shedding arrangements in his rebuttal testimony and during cross and redirect examination. Two interim load shedding arrangements were relied upon in SCE's south Orange County area until the Del-Amo-Ellis loop-in project could be completed and a different load shedding scheme was in place until the Barre-Ellis reconfiguration and the Johanna, Santiago and Viejo shunt capacitors were in place in 2013.[33] There is another interim load shedding scheme, with the potential to shed over 100 MWs, in place for the San Francisco peninsula while PG&E completes several related transmission rebuilding projects.[34]

Thus, ISO takes the same position with respect to load shedding as a transmission planning mechanism in all high urbanized areas of the grid with no other means of supply,

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[30] ISO-2, p. 5

[31] Tr. 1582:12-1584:10.

[32] ISO-2, p. 5.

[33] *Id.*

[34] Tr. 1472:13-26.

including the SCE and PG&E service territories.[35] Mr. Millar explained that this practice is also consistent with most of the ISOs throughout the United States and Canada. A decision by the Commission to the contrary suggests that the ISO should plan to a lower level of reliability and adopt load shedding to address needs in many other heavily populated, urban areas of the state, as well .[36]

*a. The Intervenors Misunderstand the Applicable NERC/WECC Transmission Planning Criteria.*

Although other parties argued that the SONGS area residual local resource needs would be reduced if the Commission authorized load shedding in response to the N-1-1 limiting contingency, Sierra Club (Bill Powers), CEJA (Julia May), POC (David Peffer) and Redondo Beach (Jaleh Firooz) presented extensive technical testimony on this point, most of which contains misunderstandings and misinterpretations of the applicable NERC reliability standards. For example, both Mr. Powers and Mr. Peffer seem to be under the impression that the ISO has the discretion to "introduce" the N-1-1 contingency as the most limiting contingency for the SONGS study area.[37] This, of course, is incorrect, because the most limiting contingency for a local capacity is determined by the ISO's study results, as Mr. Sparks explained on cross-examination:

> Q. (Peffer) Is it CAISO's position that this specific contingency, the concurrent outage of Sunrise and Southwest, is the only contingency that CAISO can use pursuant to WECC or NERC regulations?
>
> A.(Sparks) Well, I guess I'm not clear what you mean by "the only contingency."

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[35] ISO-2, p. 2.

[36] ISO-2, p. 7.

[37] *E.g.* Sierra Club-1a, p. 4: "Is treatment of the Sunrise Powerlink/Southwest Powerlink N-1-1 as the limiting contingency a fatal flaw in the Track 4 modeling? Yes."

*E.g.* POC-1, p. 4: "In 2012 CAISO introduced a new limiting contingency, N-1-1, for the San Diego local area."

> Q. Well, you relied on this as your limiting contingency, correct?
>
> A. That was a finding of the studies. We studied all the contingencies in the study area required to be analyzed by the NERC planning standards. This one was found to be the critical contingency in terms of driving the most needs in the area.
>
> Q. Okay. So—and you are saying that you want to—that CAISO wants to use this specific critical contingency in determining need, correct? This is the basis of your need determination?
>
> A. Well, again, this was the conclusion of the studies and a natural outcome of the studies. I guess I took exception to the word "wants."[38]

Mr. Powers, Ms. May and Mr. Peffer then go on to claim that the SWPL/Sunrise overlapping N-1-1 contingency is a Category D extreme event for which transmission upgrades are not required under NERC standards.[39] Mr. Sparks addressed this notion in his rebuttal testimony, where he explained that these witnesses seemed to be confusing the overlapping outages of the two lines (loss of one element, system re-adjusted, followed by loss of a second element), with the simultaneous loss of two transmission lines (a Category D contingency).[40]

On cross examination, Mr. Powers appeared to take the position 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.[41] Even if the Commission would consider giving any weight to the notion that the most limiting contingency for the SONGS study area is a

[38] Tr. 1557:21-1558:16.

[39] SC-1, p. 2; POC-1, p. 11; CEJA-1, p. 30.

[40] ISO-2, pp. 11-13.

[41] Tr. 1932:7-19. See also POC-X-CAISO-3.

"functional" Category D, SDG&E witness John Jontry quite clearly put to rest the idea that the WECC re-classification process is available for an N-1-1 contingency:

> A. (Jontry)…One thing I would point out, though, is that we're—this process is really to applying for moving an N-2 simultaneous contingency from Category C to Category D. It doesn't really apply to the N-1-1, which is for—looks at two lines that may or may not be in a common corridor, they may be at opposite ends of the system. So they may not have a common [sic-mode] failure in common.
>
> Q.(Peffer) Are you saying that this particular methodology only applies to lines in the common corridor?
>
> A.(Jontry) What it really applies to [sic-is] lines in the common corridor and also meets the WECC definition of adjacent circuits. Not all lines in common corridors meet the WECC criteria for adjacent circuits. An example would be Sunrise and SWPL aren't adjacent circuits, even though for a significant distance are in a common corridor.[42]

Mr. 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.[43]

Ms. May took a slightly different approach, arguing that the SWPL/Sunrise overlapping outage is really a Category D event because when there is an outage of these transmission lines, a CFE line (Otay Mesa to Tijuana) is also tripped. She argues that three lines removed from service is an extreme event under NERC standard TPL-004 (Category D).[44] However, Ms. May misunderstands the CFE cross-tripping arrangement. As Mr. Sparks noted in his rebuttal testimony, opening the Otay-Mesa line following the N-1-1 contingency is a planned and controlled opening of the line to protect the line and downstream facilities on the CFE system. It is not part of the contingency, but rather a controlled mitigation solution. Alternatively, the ISO could recommend additional generation to avoid opening the line, but it is more cost effective to

[42] Tr. 1775:7-27.

[43] Tr. 1562:15-27.

[44] CEJA-1, pp. 3, 29-32.

rely on the line opening. The ISO also is evaluating transmission solutions that could prevent overloading on the line.[45]

Ms. Firooz again provided testimony on the probability that the N-1-1 contingency will occur under 1-in-10 peak load conditions, a matter thoroughly addressed in Track 1 and resolved with the approval of the ISO's study methodology. Along the same lines, Mr. Powers displayed further confusion about NERC reliability standards with his statement that "the purpose of grid reliability standards is to assure that a utility can continue to provide reliable power during peak demand periods…"[46], to which Mr. Sparks pointed out that the purpose of the reliability standards is ensure that the transmission system is reliable based on deterministic analysis that considers periods of heavily stressed conditions- which can be at any time.[47]

These intervenors have provided no credible basis upon which to conclude that the ISO's analysis is somehow flawed and that the limiting contingency for the SONGS study area is anything but the N-1-1 Category C3 SWPL/Sunrise overlapping outage.

*b. Involuntary load shedding creates significant system and customer impacts.*

Several parties, including ORA and TURN, criticized the ISO for not conducting a cost benefit analysis of load shedding in response to the N-1-1 contingency versus additional resources or transmission additions.[48] Both CEJA witness May and Sierra Club witness Powers mixed apples and oranges by opining that "voluntary load shedding" provides major economic benefits for large companies[49] and Ms. Firooz opined that controlled load drop is more reliable

[45] ISO-2, pp. 11-12.

[46] Sierra Club- 1a, p. 1.

[47] ISO-2, p. 12.

[48] ORA-3, p. 8; TURN-

[49] CEJA-1, p. 35, Sierra Club-2, p. 1..

than bringing up additional generation.[50] These witnesses, through their testimony, gave the impression that a cost benefit analysis of the SDG&E load shedding scheme would be a relatively simple exercise to conduct, and that controlled load shedding has relatively minor impacts on customers.

ISO witness Neil Millar responded to the idea that the ISO should have conducted a cost benefit analysis for load shedding in response to the SWPL/Sunrise N-1-1 event. He pointed out in complex transmission systems such as the LA Basin and San Diego, the analytical tools simply are not available to conduct a probabilistic analysis of the costs of all outages and load shedding permutations.[51] He noted that there are circumstances under which the number of possible system conditions is much more limited, thus permitting meaningful input into the decision-making process, and the ISO does employ a cost benefit analysis under these more limited conditions (see discussion below about ISO grid planning standards). However, in light of the practical considerations in conducting a cost benefit analysis for load shedding in large urban areas like San Diego, which is the eighth largest city in the United States, the ISO has historically taken that position described in the previous section that load shedding is not a prudent transmission planning tool. As Commissioner Florio pointed through questions posed to Mr. Millar, controlled load shedding is a means of maintaining grid reliability by sacrificing service reliability. Mr. Millar agreed, noting that there are also system issues that have to be considered when instantaneously dropping significant amounts of load:

> …We are not talking about a gradual ramp-down. We are talking about systems that should have that load dropped from the system in under a quarter of a second. So that also sets up impacts on the system that at times are not without consequence. And it is

[50] Redondo Beach-1, p. 10.

[51] ISO-7, p. 10.

also happening at a time when the system has already been weakened by the initial disturbance. [52]

It is important to note that the SDG&E load-dropping SPS arms blocks of 500 MW[53] of load and could automatically trip up to 1000 MW. During cross-examination, Mr. Jontry explained that load shedding in these quantities is more of a "blunt instrument" than a "surgical procedure" that has to happen very quickly, and it is difficult to avoid interrupting critical facilities initially. While it might be possible to drop smaller blocks of load, Mr. Jontry stated that the blocks are probably as small as possible to address the contingency and avoid voltage collapse.[54] None of the intervenors presented any credible testimony that contradicted Mr. Jontry's explanation and supported the notion that load shedding could somehow be targeted to "non-critical load" (apparently referring to air conditioning load during peak hours), which seemed to be the basis for their recommendations that load shedding would be an acceptable alternative.[55] Notably, none of the witnesses conducted an analysis of the societal impacts of load interruptions in terms of economic costs.[56]

In response to Ms. Firooz's statement that load shedding is less complicated than bringing up generation, Mr. Sparks noted that Ms. Firooz ignores the complexities of dropping load, and the very real possibility that an armed load-tripping SPS could be inadvertently triggered and shed load when the system is not under stressed conditions. This risk is

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[52] Tr. 1681:6-22.

[53] 500 MW equates to roughly 300,000 homes.

[54] Tr. 1740:24-1743:19.

[55] See, *e.g.* Powers cross-examination Tr. 1947:10-1951:2.

[56] See *e.g.* Tr. 1951:10-15

proportional to the amount of time that the load needs to be armed. She also did not consider the complexities of communication and sensing equipment associated with load shedding.[57]

*c. The ISO Will Initiate a Stakeholder Process in Q1 2014 Regarding its Long-Standing Treatment of Load Shedding for Category C Contingencies .*

TURN witness Woodruff testified that the ISO's transmission planning policy regarding load shedding in large urban areas "may read reasonably," but it has not been documented publicly through a stakeholder process. He suggested that the ISO should be encouraged to review this issue in a more public manner. [58] In response, Mr. Millar pointed out that the ISO's Board of Governors is aware of the ISO's historic practices in regard to the consideration of N-1-1 contingencies, and that the ISO intends to address these practices in the ISO grid planning standards as part of an open stakeholder process in the first half of 2014.[59]

POC witness Peffer correctly noted that the ISO grid planning standards require that, for the Category B contingencies under NERC reliability standard TPL-002, utilities must plan for an overlapping outage of the area's largest generator unit (G-1) and the largest transmission line (L-1), sometimes referred to as the G-1, N-1. This planning standard is more stringent than the N-1 outage allowed by NERC TPL-002, but reflects the standard practice utilized by the IOUs prior to the creation of the ISO.[60] Mr. Powers also cited the ISO's G-1, N-1 standard for single contingency events, arguing that with the G-1, N-1 as the limiting contingency (apparently

[57] ISO-2, p. 14.

[58] TURN-1, p. 25, Appendix A.

[59] ISO-7, p. 10.

[60] POC-1, p. 4.

assuming load shedding for the N-1-1 contingency), "there would be minimal, if any, 'ripple effect' into SCE's LA Basin."[61]

This is not correct. According to Mr. Sparks, the incremental difference between the G-1, N-1 Category B contingency (for which load shedding is not permitted) and the N-1-1 Category C contingency is only 150- 300 MW. Unfortunately, as discussed above, the SDG&E safety net is armed to trip block of 500 MW, which is more than the amount of load needed to address the contingency.[62] Thus, the record clearly does not support the wholesale adoption of the safety net as a response to the N-1-1 contingency for SONGS local study area.

*d. The ISO's Track 4 Transmission Planning Analysis Reflects the Sunrise Benefits Addressed in A.08-12-058.*

Both Mr. Powers and Mr. Peffer argue that the N-1-1 contingency reduces the benefits of the Sunrise transmission lines that were identified in the decision that approved the CPCN for that project.[63] These arguments are misplaced, as Mr. Sparks testified.

At the time of the Sunrise proceeding, the impact of Sunrise on reducing the local capacity requirement in San Diego was calculated to be 1000 MW. This value was derived from analysis at the time, which assumed that a 3500 MW WECC path rating would be established on the Path 44 (with the definition of Path 44 modified to address the new transmission) and was provided in Mr. Sparks' rebuttal testimony [table beginning on line 19, Page 9 of 19). Mr. Sparks' rebuttal testimony also sets out the impact on local capacity needs under the N-1-1

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[61] Sierra Club-1, p.5

[62] ISO-2, p. 6-7.

[63] Sierra Club-1, pp. 5-7; POC-1, pp. 14-16. The ISO notes that the POC testimony seems to simply repeat Mr. Powers' arguments without further analysis.

analysis and demonstrated a reduction of 1100 MW; a larger benefit than was estimated at the time of the Sunrise proceeding.

Mr. Sparks also explained that once Sunrise was placed in service, the San Diego local capacity area was expanded to include the Imperial Valley substation, and the name of the area is now the "San Diego/Imperial Valley" local capacity area.[64] There are several subareas within this larger local area.

2. The ISO has Correctly Applied the G-1, N-1 Standard to the San Diego Local Area.

At pages 7-8 of his testimony, Mr. Powers testified that the ISO's assumptions regarding the operational capabilities of combined cycle generating units are "fundamentally flawed" and should not be used for the purposes of establishing the residual local area needs. Essentially, Mr. Powers argues that the ISO incorrectly assumes that the entire 604 MW output of the Otay Mesa generating unit, a combined cycle facility that is the largest generator in the local service area (the "G-1"), is offline during an outage. According to Mr. Powers, the gas turbines in a combined cycle generation facility have the ability to continue in operation when the steam turbine is out of service, and therefore the ISO should not assume that all of the Otay Mesa output is offline during an outage.

In response, Mr. Sparks pointed out that the ISO grid planning standards specifically address the loss of a combined cycle power plant module as a single generator outage standard.[65] According to standard number 5, a single module of combined cycle power plant is considered a single contingency (G-1) and must meet the performance requirements of NERC TPL-002

[64] See ISO-5.

[65] ISO-6, p. 5.

(Category B) for single contingencies. For a single transmission circuit outage with one combined cycle module out of service the system readjusted must meet these requirements.

The grid planning standards permit a re-categorization to a less stringent requirement, based on historical information. After two years of operation, an exception can be given if historical data shows that there was no outage of the combined cycle module. After three years of operation, an exception can be given if the outage frequency is less than once in three years.

Mr. Sparks explained that the ISO assessed the Otay Mesa historical performance over the period 2009-2012 and determined that the plant had outages well beyond once in three years. Indeed, Otay Mesa had 14 full plant outages over the three year period. Based on this information, there is no indication that the plant has the ability to "ride through" the loss of the steam turbine, despite Mr. Powers' claim that there are economic reasons for the facility to do so.[66] The ISO will re-consider an exception for Otay Mesa if the performance-based standard for demonstrating reliability is met, but for the present time Mr. Powers has presented no credible information that the ISO is incorrectly applying the G-1, N-1 planning standard.

3. It is Reasonable for the ISO to Increase the Amount of Modeled Load by 2.5% as Required by WECC Regional Business Practice.

SCE, in describing its studies of the local area needs without SONGS, noted that the ISO's positive reactive margin load modeling requirement, as described in the ISO's 2014 Local Capacity Technical Analysis (LCTA), is a "more stringent performance requirement than NERC reliability standards" and it was not included in the SCE studies.[67] SCE explained that its power

[66] ISO-2, p. 16.

[67] SCE-1, p. 27.

flow studies are designed to meet "minimum" NERC reliability studies so as to avoid monetary penalties and sanctions.[68]

The ISO does not agree with this position and believes that a failure to apply the reactive margins to modeled load that are a WECC Regional Business Practice could, indeed, subject a utility to monetary penalties. Mr. Sparks explained that this business practice requires system models to account for uncertainties- such as power factor, equipment mis-operation during contingencies or variations in neighboring system models- by increasing the amount of modeled load by 5% for Category A or B and 2.5% for Category C.[69] In the event of a system blackout related to inadequate system margin, it is possible that NERC would impose sanctions for a failure to follow this well-accepted and widespread business practice. Despite assertions from other parties that this 2.5% margin, along with other ISO transmission planning practices, is "too conservative," the Commission should not make adjustments that could bring about a lower level of grid reliability.

## V. SDG&E AND SCE STUDIES SUPPORT ADDITIONAL LCR PROCUREMENT AUTHORIZATION

In testimony submitted on August 26, 2013, both SCE and SDG&E described the power flow studies they conducted collaboratively to identify residual local capacity needs in the absence of SONGS. While the studies were quite similar in methodology to those conducted by the ISO, there were also differences with respect to certain input assumptions, including proposed transmission alternatives and local resource assumptions. Based on the study results, both parties identified residual resource needs and have requested authorization to procure additional resources. Although the ISO did not include proposed transmission alternatives in its

[68] *Id.,* p. 26.

[69] ISO-2, pp. 3-4.

Track 4 studies and is currently evaluating these proposals in the 2013/2014 transmission planning process, the ISO supports the SCE and SDG&E additional procurement request.

### A. The SCE and SDG&E Study Results are Consistent with the ISO's Findings

SCE and SDG&E jointly studied six local reliability scenarios and the testimony provided by each party described the particular scenarios applicable to their service territories. The scenarios represented a variety of proposed mitigation solutions for the identified residual needs in the absence of SONGS in 2022. Topology, load and resource assumptions were provided by each company for the representation of their service territories in all of the scenarios.[70] As noted by SCE, the study assumptions were largely consistent with the Revised Scoping Memo (and therefore the ISO's study assumptions), but not entirely. For example, SCE's thermal unit retirement assumptions did not include the Etiwanda units 3 and 4 or Coolwater units 2 and 4. SCE also included demand response resources as a load reduction to substation loads whereas the ISO modeled demand response as described in the Revised Scoping Memo and discussed above.[71] In addition, some of SCE's scenarios contained transmission projects not yet approved by the ISO.[72]

SCE studied four scenarios: 1) LA Basin/SDG&E Generation (jointly studied with SDG&E); 2) LA Basin Transmission (Mesa Loop-In); 3) Preferred Resources; and 4) Regional Transmission (Valley-Alberhill-SONGS). SCE also ran two sensitivity cases: LA Basin Generation without SDG&E load shedding and LA Basin Transmission without SDG&E load shedding.[73]

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[70] SDG&E- 3, pp. 3-6; SCE-1, pp. 13-15.

[71] SCE-1, p. 14.

[72] SCE-1, p.28.

[73] See, *e.g.*, SCE-1, Table III-5, p. 32.

SDG&E studied two transmission scenarios in addition to the conventional generation case along with SCE: a Regional Transmission scenario that included a 500 kV DC transmission project from Imperial Valley to SONGS Mesa; and a Regional Transmission scenario with a 500 kV AC line from Devers substation to a new 230 kV substation in north San Diego county.[74] SDG&E also ran sensitivities for these scenarios assuming both load shedding as a mitigation solution for the N-1-1 contingency, and no load shedding.[75]

Despite the differences in modeling assumptions, the ISO, SCE and SDG&E study results fell within the same range of residual resource needs for the combined SONGS study area. An "apples to apples" comparison of the total SONGS area needs can be put together from Table 3 in Mr. Jontry's opening testimony, SCE's Table III-5 and the ISO results from Table 13 in Mr. Sparks' testimony (set forth in section IV.A above), using the SCE/SDG&E study results for the Conventional Generation scenario.[76] Mr. Jontry's Table 3 shows the San Diego need as 1472 MW under N-1-1 conditions without load shedding (from SDG&E Table 2). Table 3 also shows LA Basin need as 2802 MW (from SCE-1 Table III-5) but it appears that SCE calculated that need based on load shedding by SDG&E. SCE's LA Basin Generation need determination without load shedding (Case 1S), 3240 MW, should be used to compare the study results with the ISO as follows:

[74] SDG&E-3, pp. 8-9.

[75] *Id.* pp. 10-11, Tables 1 and 2.

[76] SDG&E-3, p. 12 ; SCE-1, p. 32.

| Study Scenario | Identified Resource Need | | | Residual Resource Need[77] | | |
|---|---|---|---|---|---|---|
| | LA Basin | San Diego | Total | LA Basin | San Diego | Total |
| ISO Study: 80%/20% (LA/SD) | 3722 | 920 | 4642 | 1922 | 612 | 2534 |
| ISO Study: 80%/20% (LA/SD) | 3022 | 1485 | 4507 | 1222 | 1177 | 2399 |
| SCE Study | 3240 | 1170 | 4410 | 1440 | 862 | 2302 |
| SDG&E Study | 2802 | 1770 | 4572 | 1002 | 1470 | 2472 |

Based on this side-by-side comparison, the study results are very similar and provide the Commission with a sound basis for making procurement decisions. Indeed, the main driver of differences between the ISO and the SCE/SDG&E study results was the assumption that SDG&E would shed load in response to the N-1-1 contingency event. However, although both parties ran studies for informational purposes that included this assumption, neither party based its procurement recommendations on study results containing this assumption.[78]

In rebuttal testimony, both SCE and SDG&E provided clarification on this topic. SCE testified that the purpose of providing studies with less stringent reliability criteria was to "provide a new data point, not to attack CAISO's reliability standards."[79] SCE went on to agree with the ISO that load shedding should only be used judiciously as a mitigation for contingencies, particularly in densely populated areas.[80] Mr. Jontry stated unequivocally that "SDG&E and the CAISO are in agreement that load shedding is not a proper or prudent

[77] All Residual Resource Needs were calculated by subtracting 1800 MW from the LA Basin and 308 MW from the San Diego Identified Resource Needs.

[78] SDG&E-1, p. 2 ("…the transmission studies identified a total need of 4572MW" [no load shed scenario]); SCE-1, p. 44 ("SCE recommends procurement of 500 MW of additional resources to meet the more stringent applicable CAISO Planning Criteria")

[79] SCE-2, p. 13.

[80] *Id.,* p. 15.

mitigation for the contingency event in this proceeding (the N-1-1 of the ECO-Miguel portion of the 500 kV Southwest Powerlink, followed by the Ocotillo Express-Suncrest portion of the 500 kV Sunrise Powerlink)."[81] Consistent with the ISO and SCE, Mr. Jontry noted that controlled load shedding may be appropriate for certain localized instances or as short-term mitigation. He noted that the difference between the scenarios assuming load shedding and no load shedding was in the range of 150 MW, consistent with Mr. Sparks' 150- 300 MW range discussed above.

Thus, contrary to the arguments advanced by some parties, the information provided by SCE and SDG&E about load shedding and the level of local resources needs based on reliability criteria less stringent than the ISO's should not be used by the Commission to adopt a lower level of reliability for southern California. As Mr. Millar cautions, as the industry moves toward a wider range of operating conditions as the makeup of the resource fleet changes, it will be critical to ensure that reliability is maintained during this transitional period.[82] Now is not the time to consider lowering the level of reliability that has been consistently approved since ISO start-up.

**B. The Additional Resource Procurement Requested by SCE and SDG&E Should Move Ahead Expeditiously.**

In opening testimony, the ISO suggested that the Commission defer a decision on additional local resource procurement until after transmission mitigation solutions had been evaluated in the 2013/2014 ISO transmission planning process.[83] This testimony was submitted before SCE and SDG&E submitted testimony that included authorization for additional amounts of local resource procurement. Specifically, SCE has requested authorization to procure an

[81] SDG&E-4, p. 1

[82] ISO-7, p. 9.

[83] ISO-1, pp. 30-31.

additional 500 MW in an all source procurement, to be combined with the Track 1 procurement process. SCE explained that additional resource needs would be addressed by the Mesa Loop-In transmission project, along with the development of preferred resource development through the Living Pilot program.[84] SDG&E proposes to issue an all-source RFO for 500-550 MW of supply-side resources, including renewable resources, energy storage and CHP.[85] Other resource needs would be met through preferred resource development such as demand response, and the possibility of a major transmission project that could reduce the local need by between 1000 and 1400 MW.

Both SCE and SDG&E have requested procurement authorization for amounts less than the total resource needs in each area identified by the ISO. Given the urgency associated with maintaining reliability in these heavily populated areas, the Commission should authorize all-source procurement as requested by these parties.[86] As Mr. Millar points out, this approach is much different than a comprehensive procurement decision discussed in Mr. Sparks' opening testimony. The ISO is currently evaluating the transmission proposals presented by SCE and SDG&E in the transmission planning process, along with the evaluation of non-conventional resource alternatives that can be part of the basket of resource options, and these results will be available for Commission consideration in the next LTPP cycle and related dockets. In the meantime, the "no regrets" procurement requested by SCE and SDG&E will be underway. For all of these reasons, the ISO supports these proposals.

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[84] SCE-1, p.4.

[85] SDG&E-1, p.12.

[86] ISO-7, p. 6.

## VI. RECOMMENDATIONS BY OTHER PARTIES AND COMMENTS ON ADDITIONAL ISSUES

The Joint Comparison Exhibit sets forth the panoply of positions taken by the parties to the proceeding. The ISO notes a general acknowledgement among many parties that additional local resources are needed- whether transmission, conventional generation, renewables or preferred resources. The disagreement seems to focus on the timing of additional resource procurement and the type of resources that should be procured. For example, ORA argues that if the Commission determines to move ahead with interim procurement authorization at this time it should be limited to preferred resources.[87] Other parties suggest that the current procurement authorization targets be met, including the recently-adopted energy storage procurement targets, before additional procurement authorization is provided.[88] CEJA, NRDC, Sierra Club, EnerNOC, among others, recommend that the Track 4 input assumptions be updated to reflect load forecast changes and other changes that might reduce local capacity needs. Still others, such as CEERT and ORA, suggest waiting until the ISO's 2013/2014 transmission plan is released so that a comprehensive decision can be issued in mid-2014.

The ISO strongly urges the Commission to reject the notion that the Track 4 input assumptions should be updated now before residual capacity needs are determined, and this issue was addressed in the ISO's comments on the additional issues identified at the September 16, 2013 prehearing conference. Wholesale changes to the input assumptions will cause delays in resource procurement that could serve to stall preferred resource deployment as well as conventional resource development. At this point the Commission must act on the very substantial and robustly vetted evidence it has before it and take steps towards achieving the mix

[87] ORA-3, p. 21.

[88] See, *e.g.* CESA

of resources needed to meet the reliability identified in this proceeding. As the ISO noted above, changes to the CEC load forecast can be considered in the upcoming LTPP.

The ISO also cautions against authorizing additional resource procurement for only preferred resources rather than all-source solicitations. The ISO strongly supports preferred resource development and is working with stakeholders in various venues in order to enable these resources to meet local needs. However, there is still substantial uncertainty as to whether sufficient quantities of preferred resources will develop at the pace necessary to fill substantial resource needs as early as 2018. Indeed, monitoring the development of preferred resources will be an important aspect of future procurement planning. Given this uncertainty, it is best that the procurement authorized in this Track 4 be open to all supply-side resources.

## VII. ISO CONCLUSIONS AND RECOMMENDATIONS:

### A. The ISO's Study Methodology and Input Assumptions are Reasonable and Should be Adopted.

The Commission should not adopt a lower level of service reliability in this densely populated, urban region of southern California establishing local capacity needs for the area. There is too much at stake to engage in an exercise of "whittling away" at service reliability in the area through a combination of load shedding and overly optimistic assumptions about non-conventional resource development. The assumptions used by the ISO to conduct its power flow analysis are reasonable and should not be adjusted. Updated load assumptions, as well as transmission upgrades being developed in the 2013/2014 transmission planning process, can be considered in the upcoming biennial LTPP.

### B. The Commission Should Authorize "No Regrets" Procurement.

The ISO agrees with TURN witness Woodruff that there are no "silver bullet technologies" or combined "grand plans" that can be implemented at this time with certainty that they will meet all southern California resource needs, but that nonetheless the Commission should move forward with an all source procurement for the amounts requested by SCE and SDG&E.[89] TURN's testimony is consistent with the Preliminary Reliability Plan for the LA Basin and San Diego, which, as discussed at the outset, recommends a basket of resources to meet local capacity needs. The Commission should take the reasonable step at this juncture advocated by SCE and SDG&E and approve the requested additional procurement that will move the state towards the comprehensive mix of preferred resources, conventional generation and transmission contemplated in the Preliminary Reliability Plan.

Respectfully submitted,

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[89] TURN-1, pp.8-9.