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)

THE OFFICE OF RATEPAYER ADVOCATES' OPENING BRIEF ON LOCAL RELIABILITY PROCUREMENT TO ACCOUNT FOR THE CLOSURE OF THE SAN ONOFRE NUCLEAR GENERATING STATION

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I. INTRODUCTION

Pursuant to Rule 13.11 of the California Public Utilities Commission's (Commission's) Rules of Practice and Procedure and consistent with Administrative Law Judge Gamson's direction at the close of hearings,[1] the Office of Ratepayer Advocates (ORA) submits this opening brief on Local Reliability Procurement to Account for the Closure of the San Onofre Nuclear Generating Station (SONGS). Section II of this brief contains ORA's recommendations, Section III summarizes the background, and Section IV explains ORA's rationale for its recommendations. Appended as Attachment A are ORA's proposed findings of fact and conclusions of law.

II. SUMMARY OF RECOMMENDATIONS

- The Commission should base its determination of procurement need to account for the closure of SONGS on a complete record of feasible mitigations, including the California Independent System Operator Corporation (CAISO)'s 2013/2014 Transmission Planning Process (TPP) results, which are expected to be available in draft in January 2014.
- The Commission should authorize each utility to procure resources in an amount that minimizes total procurement in the entire SONGS study area.[2]
- If the Commission decides to authorize procurement based on the current record, ORA recommends that the Commission authorize:
  - Southern California Edison Company (SCE) to procure 700 megawatts (MW) of preferred resources;[3] and

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[1] Reporter's Transcript (RT) 2304:9.

[2] The SONGS study area is comprised of the Los Angeles (LA) basin of SCE's service territory and the entire SDG&E service territory.

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

ORA's brief adopts the same convention that SCE uses in its testimony and for ease of reference, includes energy storage as a preferred resource, even though energy storage is a potential enabling technology that stores power regardless of how it is produced. Ex. SCE 1/Nelson (Track 4 Testimony of Southern California Edison Company, August 26, 2013,), p. 1, fn. 1.

- San Diego Gas & Electric Company (SDG&E) to procure 400 MW of preferred resources, and an additional 215 to 350 MW in an all-source request for offers (RFO).

- The Commission should update any interim procurement authorization based on the 2013/2014 TPP.
- The Commission should recognize that there is sufficient time to meet 2022 local capacity reliability (LCR) need in the SONGS study area using preferred resources, SCE's proposed Mesa Loop-In transmission upgrade, and additional reactive power resources, because there are interim solutions to bridge the potential gap between when the preferred resources, the Mesa Loop-In transmission upgrade, and the additional reactive power resources are needed and when they are available. Potential interim solutions include:
    - the possible limited extension of the compliance deadline of the most electrically effective once-through cooling (OTC) facilities;
    - reliance on the existing special protection system (SPS)[4] as a bridge until the resources are in place because the use of an SPS to mitigate the N-1-1 contingency decreases the need for new generation and increases the effectiveness of existing transmission; and
    - reliance on the proposed contingent site development or energy park (also known as local development reserves) currently under consideration by SCE and SDG&E.

[4] A special protection system (SPS) is designed to protect the integrity and stability of the electric grid by automatically taking corrective actions to limit the impact of an extreme event and to meet system performance requirements identified in the North American Electric Reliability Corporation (NERC) Reliability Standards. SPSs are designed to maintain system stability, including acceptable system power flows and voltages. See Ex. ORA 3/Fagan (Reply Testimony of Robert M. Fagan on behalf of ORA, September 30, 2013), Attachment A.

As explained in Section IV G of this brief, the existing SPS is currently in place to address a G-1/N-1-1 contingency, but could potentially be used to address the N-1-1 contingency at issue in the SONGS study area until other solutions are available. G-1 refers to the loss of a generation facility, while N-1-1 refers to the sequential loss of two transmission lines

- Decisions regarding service reliability should be based on a record that includes reasonable information regarding costs, benefits, affordability, and risks.
- The Commission should allocate Track 4 LCR costs to all benefitting customers in the SONGS study area, including bundled customers, direct access (DA) customers and Community Choice Aggregation (CCA) customers.

III. BACKGROUND

A. Track 1 and Application (A.) 11-05-023 authorized SCE and SDG&E to procure LCR resources.

Track 1 of this proceeding considered the local capacity reliability (LCR) need[5] for SCE in 2022 following the anticipated retirement of generating resources located in the Los Angeles basin and the Big Creek/Ventura areas, two local capacity areas in SCE's service territory. The Commission determined LCR need for SDG&E in a separate proceeding, A.11-05-023. The Commission authorized SCE to procure up to 1800 megawatts (MW) of new resources,[6] and authorized SDG&E to procure 298 MW of new resources, in addition to the Escondido Purchased Power Tolling Agreement (PPTA), effectively authorizing 308 MW of new LCR for SDG&E.[7]

B. Track 4 considers additional LCR need given the SONGS outage.

On May 21, 2013, Commissioner Florio and Administrative Law Judge Gamson issued a "Revised Scoping Ruling and Memo of the Assigned Commissioner and Administrative Law Judge" (Revised Scoping Memo), establishing Track 4 of this proceeding to "consider the local reliability impacts of a potential long-term outage at the San Onofre Nuclear Power Station

[5] A local capacity area is a geographic area without sufficient transmission import capability to serve the electrical demand in the area, which therefore requires local generation to meet customer demand. The minimum amount of resources needed within a local capacity area to address reliability concerns following the occurrence of contingencies on the electric system is known as the local capacity requirement or LCR.- Track 1, Ex.ISO 1/Sparks, p. 3:28-30.

[6] D.13-02-015, Ordering Paragraph 1, p. 130.

[7] D.13-03-029, Ordering Paragraphs 1, p. 26 and 3, p.27.

(SONGS) generators, which are currently not operational."[8] The Revised Scoping Memo requested that CAISO perform power flow modeling[9] to determine LCR need in the SONGS study area, comprised of the Los Angeles basin in SCE's service territory and SDG&E's entire service territory. The Revised Scoping Memo requested that the CAISO model three separate cases: 2022 without SONGS, 2022 with SONGS, and 2018 without SONGS.[10]

C. The Joint Parties requested that the Commission ask CAISO to model a reasonable range of reactive power options to identify the need for real power in the absence of SONGS.

SCE announced the permanent retirement of SONGS on June 7, 2013.[11] On June 28, 2012, ORA, along with the California Environmental Justice Alliance (CEJA) and Sierra Club California filed a motion[12] noting the closure of SONGS and requesting that since modeling the case that assumed the availability of SONGS in 2022 now appears less relevant, the Commission request that CAISO focus its finite resources on modeling the cases without SONGS, but including the full range of reactive power[13] resources identified in CAISO's 2012-2013 Transmission Plan.

Reactive power is an essential component to a solution for the SONGS retirement given SONGS' strategic location and role in providing voltage support.[14] Power flow modeling results

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[8] Revised Scoping Memo, p. 4.

[9] SCE explains that "transmission power flow studies assess the capability of the electric system to operate under normal and emergency conditions. This involves determining whether an initiating fault (short circuit) and subsequent loss of electric facilities (such as transmission lines, generators, transformers, bus sections and breakers) violates system performance requirements specified by the NERC [North American Electricity Council Reliability Standards.]" Ex. SCE 1/Chinn, p. 20:20-21:2.

[10] Revised Scoping Memo, Attachment A, p. 2.

[11] Edison International press release, June 7, 2013: http://newsroom.edison.com/releases/southern-california-edison-announces-plans-to-retire-san-onofre-nuclear-generating-station See Letter to U.S. Nuclear Regulatory Commission, Subject: "Docket Nos. 50-361, 50-362, Certification of Permanent Cessation of Power Operations, San Onofre Nuclear Generating Station Units 2 and 3" (executed June 2, 2013).

[12] Joint Motion of the Division of Ratepayer Advocates, California Environmental Justice Alliance, and Sierra Club California to Amend the Revised Scoping Memo to Reflect the Closure of the San Onofre Nuclear Power Station Generating Facilities, June 28, 2013 (Joint Motion).

[13] Reactive power must be present in the transmission and distribution system to keep electrical current and voltage in phase and to operate electrical equipment with inductive load, such as motors, magnetic equipment, and transformers. Resource: An Encyclopedia of Energy Utility Terms, Pacific Gas and Electric Company, 1992. Reactive power capacity is measured in units of volt-ampere reactive or var.

[14] RT 1678:1-6, ISO/Millar (SONGS was "critical in supporting voltages and transfers into San

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that exclude the full available range of reactive power options make it difficult to identify the true impact that reactive power can have in reducing new procurement need. CAISO's analysis in its 2012-2013 Transmission Plan demonstrated that many hundreds of megawatts of procurement can be avoided by effectively deploying more reactive power.[15] The Utility Reform Network (TURN) agreed that the impact of "reactive power alternatives should be considered by this Commission in assessing how to respond to the SONGS retirement."[16] The CAISO opposed the joint motion to include modeling of additional reactive power resources in its Track 4 modeling.[17] The joint motion is still pending.

D. The CAISO's August 5, 2013 Testimony identified residual need in the absence of SONGS ranging from 2399 MW to 2534 MW, but recommended that the Commission wait until the CAISO had completed its studies before authorizing procurement.

The August 5, 2013 Testimony of Robert Sparks on behalf of the CAISO identified residual resource needs in 2022 given the absence of SONGS.[18] The CAISO's power flow modeling identified LCR need for the SONGS study area in 2022, then subtracted the prior authorization from D.13-02-015 (1800 MW for SCE) and D.13-03-029 (A.11-05-023, 308 MW for SDG&E, including 298 MW plus a 10 MW net increase for the Escondido PPTA). The results showed a residual need of 2399 MW if two thirds of the resources were located in the west LA basin and one third of the resources were located in SDG&E's service territory. If the resources were located 80% in the west LA basin and 20% in SDG&E's service territory, the

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Diego….")

[15] Ex. ORA 3/Fagan, Attachment L, 2012-2013 Transmission Plan, March 20, 2013, pp. 190-193. Available at http://www.caiso.com/Documents/BoardApproved2012-2013TransmissionPlan.pdf.

[16] Response of The Utility Reform Network to the Joint Motion of the Division of Ratepayer Advocates, California Environmental Justice Alliance, and Sierra Club California to Amend the Revised Scoping Memo to Reflect the Closure of the San Onofre Nuclear Power Station Generation Facilities, July 15, 2013,p. 1.

[17] Response of the California Independent System Operator Corporation to Joint Motion to Amend the Revised Scoping Ruling of Division of Ratepayer Advocates, California Environmental Justice Alliance and Sierra Club California, July 15, 2013, p. 2 ("Although the SONGS retirement announcement does alter the landscape of local generation needs in the SDG&E and SCE areas and removes uncertainties with regard to long term resource availability, the ISO opposes this motion.")

[18] Ex. CAISO 1/Sparks (Track 4 Testimony of Robert Sparks on behalf of the California Independent System Operator Corporation, August 5, 2013), Table 13 at p. 26.

residual need increased to 2534 MW. The increase in the total need as a result of the location of the resources occurs because resources located in SDG&E's service territory are more electrically effective in resolving the limiting contingency in the SONGS study area, which is the sequential loss of the ECO-Miguel section of the Southwest Powerlink 500 kV line and the Ocotillo Express Suncrest section of the Sunrise Powerlink, an N-1-1 contingency that system operators must be prepared to address as required by North American Electricity Council (NERC) and Western Electric Coordinating Corporation (WECC) standards.[19]

Notwithstanding the range of need identified in its August 5, 2013 testimony, the CAISO recommended that the Commission "wait to make a decision about the need for additional resources until the ISO has completed its studies of potential transmission mitigation solutions (including the need for additional reactive support.)"[20] The CAISO acknowledged that such information would allow the Commission to consider the appropriate mix of resources that would meet local reliability needs related to the SONGS retirement, taking into account location and effectiveness of those resources.[21]

E. The August 26, 2013 testimonies of SDG&E and SCE requested a total of 1050 MW in interim procurement authority.

SCE and SDG&E each submitted testimony on August 26, 2013 based on power flow studies that reflected transmission upgrades, including reactive power resources, not studied by the CAISO. SCE and SDG&E began their studies in advance of the Revised Scoping Memo; accordingly, the utilities' assumptions are not identical to those used in the Revised Scoping Memo.[22] The testimony of SCE and SDG&E reflecting additional transmission solutions including reactive power resources is helpful, but ideally, before authorizing the procurement of new resources the Commission would consider SCE and SDG&E's testimony in conjunction with the CAISO's 2013/2014 TPP plan results.

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[19] Ex . SDG&E 3/Jontry (Prepared Track 4 Direct Testimony of San Diego Gas & Electric Company, August 26, 2013, John M. Jontry), p. 3:5-7.

[20] Ex. CAISO 1/Sparks, p. 31:1-4.

[21] Ex. CAISO 1/Sparks, p. 31:4-7.

[22] Ex. SDG&E 1/Anderson, p. 2:1-8.

1. SCE requests that the Commission authorize procurement of 500 MW in an all-source RFO.

SCE modeled four scenarios and two sensitivities to resolve the limiting contingency in the SONGS study area.[23] Table III-5 of SCE's Opening Testimony summarizes the results of the scenarios: the LA Basin Generation Scenario, which relied on new generation in the LA basin; the LA Basin Transmission Scenario, which included the proposed Mesa Loop-In project; the Preferred Resources Scenario, which included the Mesa Loop-In project and 678 MW of preferred resources, and the Regional Transmission Scenario, which included the Mesa Loop-in project and studied the conceptual Valley-Alberhill-SONGS transmission project.[24] The Mesa Loop-In:

> "involves rebuilding and upgrading the existing Mesa 230 kV substation in the LA Basin to 500 kV and looping the Vincent – Mira Loma 500 kV line and two 230kV lines into the substation. The Mesa Loop-In has relatively limited impact outside of SCE's existing right of way."[25]

Notably, only the Preferred Resources Scenario included any additional preferred resources beyond those specified in the Revised Scoping Memo. There was no modeling of a scenario including Mesa Loop-in, a 500 kV conceptual project, and incremental preferred resources.

SCE modeled sensitivities to the LA Basin Generation Scenario and the LA Basin Transmission Scenario, which study the impact of excluding reliance on a SPS in SDG&E's service territory. Those scenarios indicated higher need in the event reliance on load shedding was excluded as a possible mitigation for the N-1-1 contingency. SCE noted that

> "[t]he development of Mesa Loop-In and the strategically located Preferred Resources could displace the need for any additional new LCR resources, while still meeting NERC Reliability Standards. However, about 500 MW of new resources is still needed to meet the CAISO's higher expectation of need."[26]

SCE therefore requests that the Commission authorize procurement of 500 MW in an all-source RFO, which it proposed to combine with its previously authorized Track 1 RFO for 200 MW of

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[23] Ex. SCE 1/Chinn p. 29: 13-14.

[24] Ex. SCE 1A/Chinn, p. 32.

[25] Ex SCE 1/Silsbee, p. 17:6-9.

[26] Ex. SCE 1/Nelson, p. 3:10-13.

"all technologies" resources, if consistent with the loading order.[27] SCE opposed the CAISO's request to defer procurement authorization until the 2013/2014 TPP results are available.[28]

2. SDG&E requests that the Commission authorize procurement of 500—550 MW in an all-source RFO.

SDG&E modeled three scenarios. Those included an all generation case (modeled jointly with SCE) and two regional transmission projects: the Imperial Valley –SONGS 500 direct current (DC) line from Imperial Valley to SONGS Mesa; and Devers--North County Generation, a 500 kV alternating current (AC) project from Devers substation to a new 230 kV substation in north San Diego.[29] SDG&E modeled these three scenarios for two different limiting contingency circumstances: G-1/N-1, and N-1-1,[30] although CAISO's analysis finds that the Category C N-1-1 limiting contingency is the relevant binding constraint for SONGS-area LCR need assessment.[31] SDG&E's power flow modeling included the proposed Suncrest +/- 240 mega volt-ampere reactive (MVAR) synchronous condenser and the proposed Canon/Encina +/- 240 MVAR synchronous condenser, which CAISO did not study.[32]

SDG&E noted that

> "Planning analyses performed by the CAISO supporting the Final 2013 LCR Technical Study indicate that adherence to the N-1-1 criteria without the possibility of load shedding increases the LCR requirements for the San Diego LCR area by over 1000 MW, the equivalent of two combined cycle units. The large performance gap between the N-1-1 and G-1/N-1 in the CAISO's 2013 LCR analysis is caused by the loss of reactive support due to the SONGS generation retirement."[33]

SDG&E did not rely on the SPS in calculating its LCR need in the absence of SONGS and identified a "minimum generation need ranging from 620 MW and 1470 MW of net

[27] Ex. SCE 1/Cushnie, p. 55: 15-18, and p. 56, Table VI-6.

[28] Ex. SCE 1/Nelson, p. 4.

[29] Ex. SDG&E 3/Jontry, pp. 8-11, including Tables 1 and 2. SDG&E notes that the final projects submitted to CAISO may differ slightly but will be electrically equivalent.

[30] Ex. SDG&E 3/ Jontry, p. 10-11, Table 1 and Table 2.

[31] Ex. CAISO 1/Sparks, p. 21: 3-8.

[32] Ex. SDG&E 3/ Jontry, p. 5:10-11.

[33] Ex. SDG&E 3/ Jontry, pp. 7-8.

qualifying capacity (NQC) in the San Diego LCR sub-area.[34] SDG&E requests that the Commission authorize an RFO for between 500-550 MW of additional supply side resources. SDG&E opposed the CAISO's request to defer procurement authorization until the 2013/2014 TPP results are available.[35]

F. ORA's September 30, 2013 reply testimony opposed interim procurement authorization and questioned the CAISO's refusal to consider the use of an SPS as an interim or long term solution to the SONGS contingency.

ORA opposed the interim procurement authorization requested by SCE and SDG&E, and recommended that the Commission wait until the CAISO's 2013/2014 TPP results are available.[36] Mr. Caldwell testified for the Center for Energy Efficiency and Renewable Technologies (CEERT) that there are viable transmission enhancements to improve real and reactive power flows into the Southern California grid that should be factored into any Track 4 procurement decision, yet the studies that would allow this are not currently in the record. Mr. Caldwell concluded that "it is simply not possible to make a reasoned decision about residual conventional generation procurement without knowledge of the results and integration of this work into the record."[37]

While ORA opposed interim procurement, it recommended that any SONGS LCR procurement be for preferred resources only.[38] A number of parties, including Pacific Gas and Electric Company, AES Southland, NRG Energy, Western Power Trading Forum, the Independent Energy Producers Association and TURN supported some form of interim procurement.[39]

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[34] Ex. SDG&E 3/ Jontry, p. 2:18-19.

[35] Ex. SDG&E 1/ Anderson, p. 3:9-22. Ex. CEERT 1/Caldwell), p.11-3: 8 – 10.

[36] Ex. ORA 3/Fagan, p. 18:5-10.

[37] Ex. CEERT 1/Caldwell (CEERT SONGS Track 4 Opening Prepared Testimony, September 30, 2013), p.11-3:8 – 10.

[38] Ex. ORA 1/Ciupagea (Reply Testimony of Radu Ciupagea, September 30, 2013), p. 7:3-4.

[39] Ex. PG&E 1/Frazier Hampton (Pacific Gas and Electric Company 2012 Long-Term Procurement Plan Track 4 – Local Reliability Needs without SONGS Prepared Testimony, September 30, 2013), p. 1-3; Ex. AES 1/Ballouz (Track 4 Prepared Testimony of Hala N. Ballouz on behalf of AES Southland, September 30, 2013), pp. 2-4; Ex. NRG 1/Theaker (Track 4 Testimony of Brian Theaker on behalf of NRG Energy, Inc. September 30, 2013), p. 5; Ex. WPTF 1/Ackerman, (Testimony of the Western Power Trading Forum on Track 4 Issues, September 30, 2013), p.4; Ex. IEP 1/Monsen, (Testimony Of William

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ORA, TURN, CEJA, California Large Energy Consumers Association (CLECA) and Sierra Club California questioned the refusal of the CAISO, SDG&E and SCE to consider the use of an SPS to mitigate the SONGS contingency in the absence of more complete information about the costs, benefits risks and affordability of relying on the SPS,[40] an option permitted by NERC and WECC standards.[41]

Mr. Fagan pointed out that an SPS could serve as a

> "'bridge' measure, depending on future transmission and/or preferred resource development circumstances. For example, if a new 500 kV transmission connection between SCE and San Diego.. was under consideration, there might be a period of time after OTC unit retirement and prior to completion of such a project that the SPS could serve as a bridge to ensure reliability. Or, if preferred resource development is advancing rapidly but has not yet reached a required threshold level by.. 2020, but would reach such a level a few years later, the SPS could serve as a bridge during that period."[42]

CLECA posed the question:

> "Is it a good use of ratepayer money to add yet another roughly 500-1500 MW in resources that will rarely if ever be used instead of using controlled load shedding by SDG&E in the case of an N-1-1 contingency under a 1-in-10 peak load condition? This is not a matter of failing to meet NERC and WECC requirements. This is a matter of having ratepayers foot the bill for going beyond those requirements."[43]

Mr. Woodruff for TURN emphasized that consideration of whether to allow load shedding to mitigate the key N-1-1 contingency should not be confused with a lack of concern about reliability.[44]

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A. Monsen on behalf of the Independent Energy Producers Association Concerning Track 4 of the Long-Term Procurement Plan Proceeding, September 30, 2013), p.8; and Ex. TURN 1/Woodruff (Prepared Direct Testimony of Kevin Woodruff on behalf of the Utility Reform Network regarding Track 4—SONGS Retirement, September 30, 2013), p. 3.

[40] Ex. ORA 3/Fagan, pp. 3-10; Ex. TURN 1/Woodruff, pp. 12-27; Ex. CEJA 1(Prepared Testimony of Julia May on behalf of California Environmental Justice Alliance (CEJA) re Track 4 (SONGS), September 30, 2013), pp. 34-38; Comments of the California Large Energy Consumers Association, September 30, 2013 (CLECA Comments), pp. 10-1; Ex. SC 1/Powers, Prepared Opening Testimony Of Bill Powers on Behalf of Sierra Club California, September 30, 2013), pp. 1-11.

[41] Ex. ORA 3/Fagan, p.7: 15 and Attachment B, p. 1.

[42] Ex. ORA 3/Fagan, p.11:17-25.

[43] CLECA Comments, pp. 10-11.

[44] Ex. TURN 1/Woodruff, pp. 26:24-27:5.

G. The October 14, 2013 rebuttal testimony of SDG&E, SCE and the CAISO provided no additional analysis on the costs, benefits, risk or affordability and risk of using an SPS to mitigate the limiting N-1-1 contingency.

Mr. Chinn testified in his October 14, 2013 Rebuttal Testimony that SCE believes that "load shedding should only be used judiciously as mitigation for contingencies."[45] Mr. Jontry for SDG&E testified that SDG&E and the CAISO agree that load shedding for the critical N-1-1 contingency is "not a proper or prudent mitigation."[46] Mr. Jontry criticized the "suggestion that it should be the policy of the state to deemphasize electric service reliability,"[47] but added no specific estimates of the impact of the load shedding in terms of frequency, duration, cost or affordability. Mr. Millar testified for the CAISO that "performing detailed cost benefit analysis in every case of considering reinforcement beyond the minimums established by NERC is not a practical consideration in all cases and not a practical consideration in this particular case."[48]

Mr. Millar also modifies the CAISO's earlier support for a holistic consideration of need as expeditiously as possible, taking into account the 2013/2014 TPP.[49] Instead, Mr. Millar testifies that "it is urgent for the Commission to authorize an all-source procurement for SCE and SDG&E for the amounts requested."[50]

IV. DISCUSSION

A. The Commission should authorize additional procurement for the SONGS study area on the basis of a complete record of available solutions.

ORA recommends that the Commission consider the CAISO's 2013/2014 Transmission Planning Process in determining need for the SONGS study area. The results, which will be

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[45] Ex. SCE 2/Chinn (Track 4 Rebuttal Testimony Errata of Southern California Edison Company (Revised 10/24/13), p. 15.

[46] Ex. SDG&E 4/Jontry(Prepared Track 4 Rebuttal Testimony of San Diego Gas & Electric Company), p. 1:15-18.

[47] Ex. SDG&E 4/Jontry, p. 7:4-6.

[48] Ex. ISO 7/Millar, (Track 4 Rebuttal Testimony of Neil Millar on behalf of the California Independent System Operator Corporation, October 14, 2013), p. 10:13-16.

[49] The CAISO's attorney Ms. Sanders stated that the CAISO would be able to file its transmission planning results in approximately the third week in January 2014, allowing the Commission third quarter of 2014. RT 290:10-291:1.

[50] Ex. ISO 7/Millar, p. 6:25-26.

available in January 2014,[51] would allow the Commission to determine need and then authorize procurement based on a record that includes the effect of feasible reactive power solutions and transmission upgrades. This is important given the material effect on resource need of additional reactive resource and key transmission (i.e., Mesa Loop-In) projects that the CAISO has not yet modeled. No party disputes that reactive power solutions can reduce the need for new generation since they allow increased utilization of the existing transmission grid; no party disputes that CAISO's analyses do not include the effect of modeling such additional reactive resources and certain transmission projects. Although SCE and SDG&E modeled transmission solutions including reactive power upgrades that the CAISO omitted, neither SCE nor SDG&E modeled the effect of all conceptual mitigation solutions on LCR need across the entire SONGS study area.[52]

SCE erroneously characterizes the recommendation of ORA and others that the Commission's decision to authorize incremental procurement be informed by a complete record as not supporting prompt action in response to the SONGS closure.[53] In fact, ORA and other parties filed a motion nearly five months ago[54] so that the Commission would have information relating to feasible transmission upgrades and reactive power solution in order to reach a timely decision that "identif[ies] the best solutions to replace SONGS" and avoids "significant, expensive over procurement that undermines California's greenhouse gas (GHG) reduction goals."[55]

B. The Commission should authorize procurement in the SONGS study area so that it minimizes total procurement.

When considering the authorization of new LCR resources in SONGS study area, the Commission should rely on power flow studies that evaluate need in the entire SONGS study

[51] RT 1543:13-17 (CAISO witness Mr. Spark testified that in January to issue a holistic decision in the second or, the CAISO will "post a draft report which will include or comprehensive transmission plan findings in terms of reliability upgrades, policy upgrades, economic upgrades.") .

[52] Ex. ORA 1/Ciupagea, p. 14:1-13; Attachment A, p. 2.

[53] Ex. SCE 2/Cushnie), 22:12-15.

[54] Joint Motion of the Division of Ratepayer Advocates, California Environmental Justice Alliance, and Sierra Club California to Amend the Revised Scoping Memo to Reflect the Closure of the San Onofre Nuclear Power Station Generating Facilities, June 28, 2013 (Joint Motion).

[55] Joint Motion, p. 6.

area to minimize total ratepayer cost and GHG emissions.[56] SCE and SDG&E's power flow studies do not include a scenario that investigates the combined effect of all conceptual reactive power and transmission solutions proposed by the utilities on LCR need in the SONGS study area.[57] The CAISO studies do not include all possible mitigation solutions, but present two options (80%/20% and two thirds/one third) that show that the location of the resources impacts the total required procurement.[58] According to the CAISO, there is a 1.24 MW reduction in the LA Basin for every 1 MW of generation that is added to San Onofre switchyard.[59] In authorizing any new LCR resources for the SONGS study area, the Commission should use the scenario that minimizes total ratepayer costs and GHG emissions in the entire SONGS study area.

C. If the Commission authorizes procurement for the SONGS study area based on the current record, then it should authorize procurement of between 1315 and 1450 MW, with an emphasis on preferred resources.

If the Commission believes it should authorize procurement at the current time and in the absence of complete information, then based on the current record ORA recommends that the Commission authorize procurement of at least 1100 MW (effective capacity, accounting for peak impact factor for PV) of preferred resources: 700 MW in SCE service territory and 400 MW in SDG&E service territory. As explained below, these recommended amounts of preferred resources are based on potential discussed in the Revised Scoping Memo, but not included in CAISO's power flow modeling. ORA therefore takes a different approach than parties who contend that the availability of preferred resources beyond the amount modeled pursuant to the Revised Scoping Memo further reduces need in the SONGS study area.[60]

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[56] Ex. ORA 1/Ciupagea, p. 9:16-18.

[57] Ex. ORA 1/Ciupagea, p. 12:12-14.

[58] Ex. ISO 1/Sparks, p. 24: 16 – 25: 4.

[59] Ex. ISO 1/Sparks, p. 24:2-3. The increase in the total need depending on the location of the resources occurs because resources located in SDG&E's service territory are more electrically effective in resolving the limiting contingency in the SONGS study area.

[60] Ex. CEJA 1/May, pp. 14-15 (explaining that second contingency DR and DG should be used to reduce need); Ex. NRDC 1/Martinez (Track 4 Opening Testimony of the Natural Resources Defense Council September 30, 2013), p. 1 (explaining why LCR need should be reduced to account for energy efficiency savings that were underestimated).

See also RT 1573-1576:15. In response to questions from ALJ Gamson, Mr. Sparks testified for the CAISO that it might be reasonable to reduce demand for second contingency PV "assuming there's

(continued on next page)

Instead, ORA's recommendation for authorization of 1100 MW of preferred resources to meet identified LCR need is based on the potential recognized in the Revised Scoping Memo. In addition, ORA recommends that the Commission authorize SDG&E to procure between 215 and 350 MW of resources in an all-source RFO.

Authorization of at least 1100 MW of preferred resources is approximately aligned with the level of preferred resource availability not modeled by CAISO and noted in the Revised Scoping Memo, as explained below, and is slightly higher than the August 30, 2013 Preliminary Reliability Assessment Report, which recommended procurement of 1000 MW of preferred resources.[61]

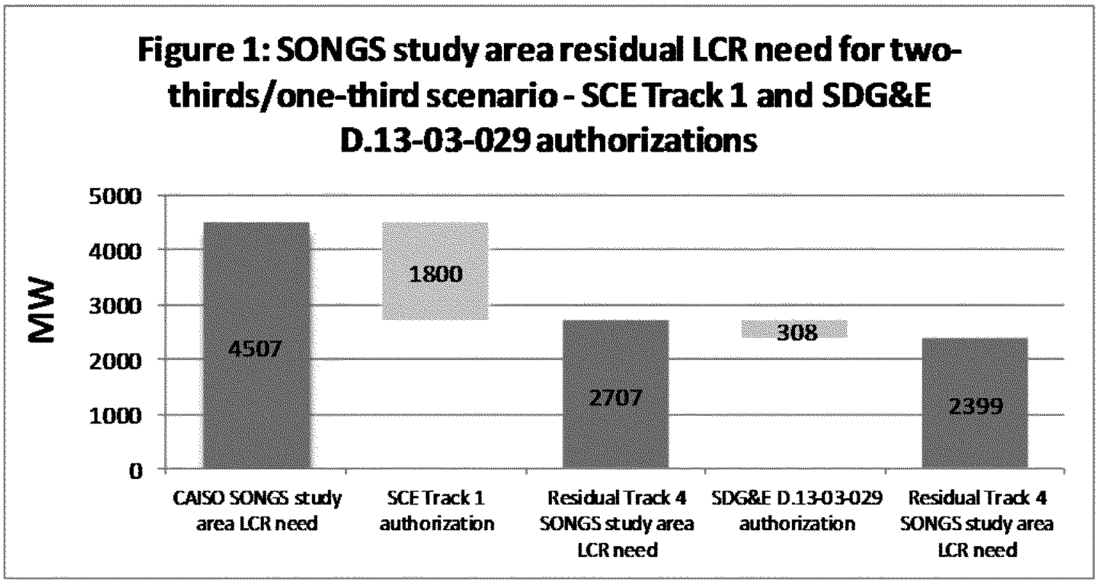
As shown in Figures 1 and 2 below, ORA calculated these amounts by starting with the gross need shown in Tables 11, 12 and 13 of Exhibit CAISO 1, then subtracting procurement authorized in D.13-02-015[62] and D.13-03-029.[63]

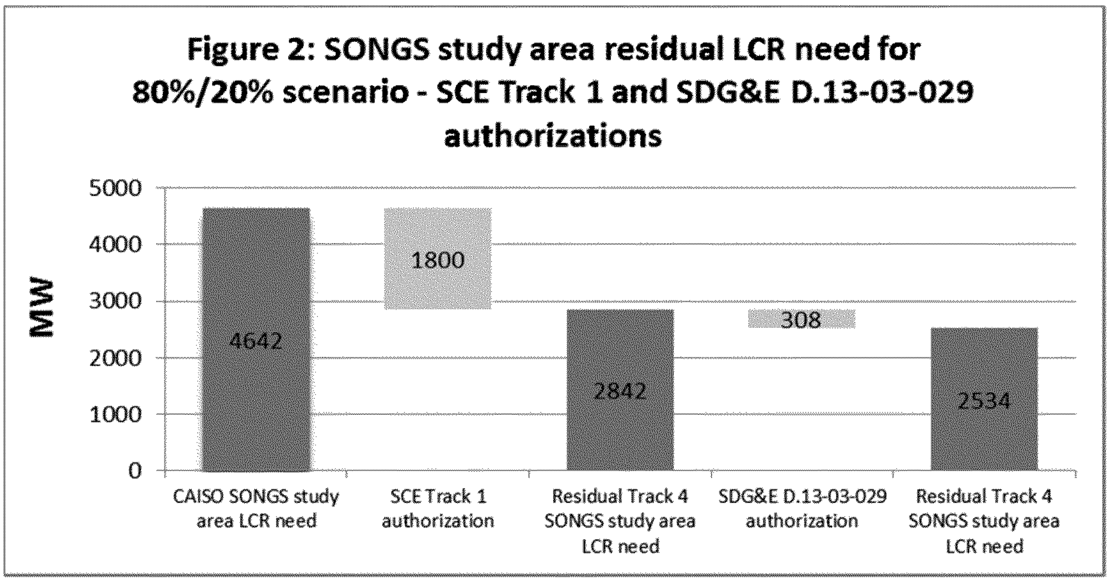
(continued from previous page)
funding and it shows up in the effective areas of the SONGS study area" but that post second contingency DR includes existing programs that have not historically been effective in meeting first contingency need. While using second contingency PV and DR to reduce demand is one approach, ORA's use of these resources to meet LCR need is another approach.

[61] Ex. ORA 5/Rogers (Reply Testimony of Nika Rogers, September 30, 2013), Attachment A *Preliminary Reliability Plan for LABasin and San Diego* Prepared by Staff of the California Public Utilities Commission, California Energy Commission, and California Independent System Operator Draft August 30, 2013, p. 7.

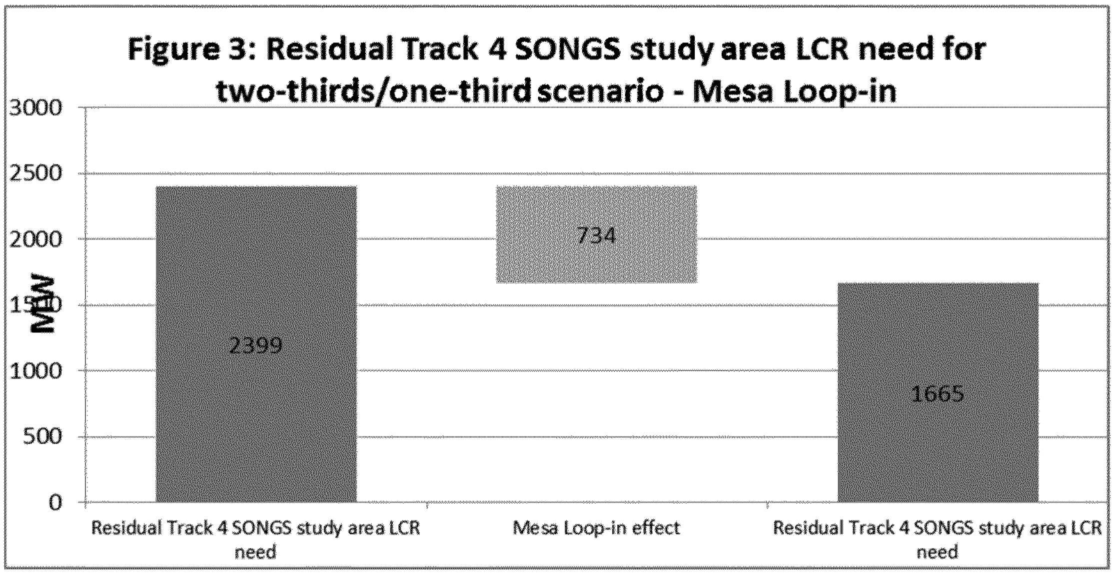
[62] D.13-02-015 authorized SCE to procure up to 1800MW, including up to 550 MW of non- storage preferred resources. (Ordering paragraph 1, pp. 130-131.)

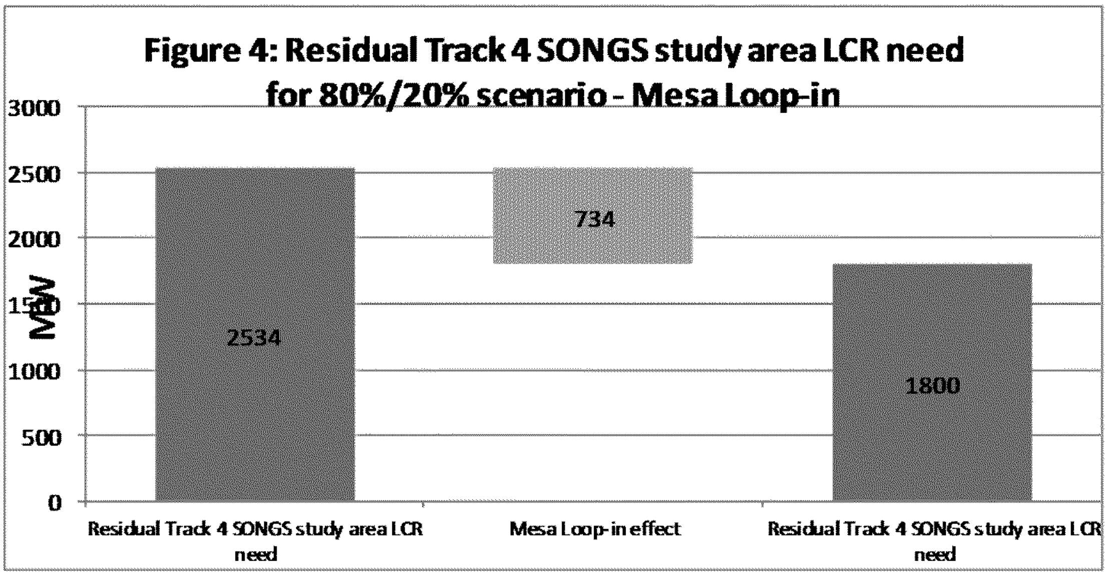
[63] D.13-03-029 authorized SDG&E to procure 298 MW of new local generation and authorized the Escondido Energy Center purchase power tolling agreement for a total of 308 MW. (Ex. ISO 1, Table 13, p. 26, line 6.)





Next, ORA subtracted the minimal expected impact of the Mesa Loop-In (734 MW) from the CAISO's SONGS study area need of 2399 MW (two third/one third scenario) or 2534 MW (80%/20% scenario), which yields an LCR need ranging from 1665 MW to 1800 MW as shown in Figures 3 and 4 below.





Finally, ORA assumed an additional 350 MW reduction in need to approximate dynamic reactive power resources expected to reduce need but not reflected in CAISO's Track 4 modeling. CAISO's witness Mr. Millar predicted in December 2012 that reactive power resources in the SONGS area along with additional transformation and lower-voltage transmission upgrades can displace the need for real power by approximately 700 MW.[64]

[64] Ex. ORA 3/Fagan, Attachment K, slide 10 from December 2012 briefing to CAISO Board of Governors.

The CAISO modeled 720 MVAR of dynamic reactive support in its Track 4 studies, while SCE/SDG&E (jointly) modeled 1,220 MVAR of dynamic reactive support, a difference of 500 MVAR of dynamic reactive resources.[65] The CAISO's Track 4 modeling did not include SDG&E's proposed Suncrest +/- 240 mega volt-ampere reactive (MVAR) synchronous condenser and the proposed Canon/Encina +/- 240 MVAR synchronous condenser; though CAISO did include "exploratory" assessment of additional dynamic reactive support in its 2012/13 TPP planning cycle.[66] CAISO's 2012/13 TPP indicated that SONGS-area LCR needs decrease by 300 MW for the specific sensitivity of adding an additional 550 MVAR at the San Onofre switchyard.[67] CAISO acknowledged that it "is evaluating transmission alternatives that will be able to address a portion of the identified resource needs and recommends that "this information should be considered in the LTPP."[68] ORA's proposed 350 MW reduction in need attempts to approximate the impact of additional reactive power resources expected to decrease the need for real power, but ORA recommends that this estimate be confirmed by comprehensive power flow studies in CAISO's 2013-2014 TPP.

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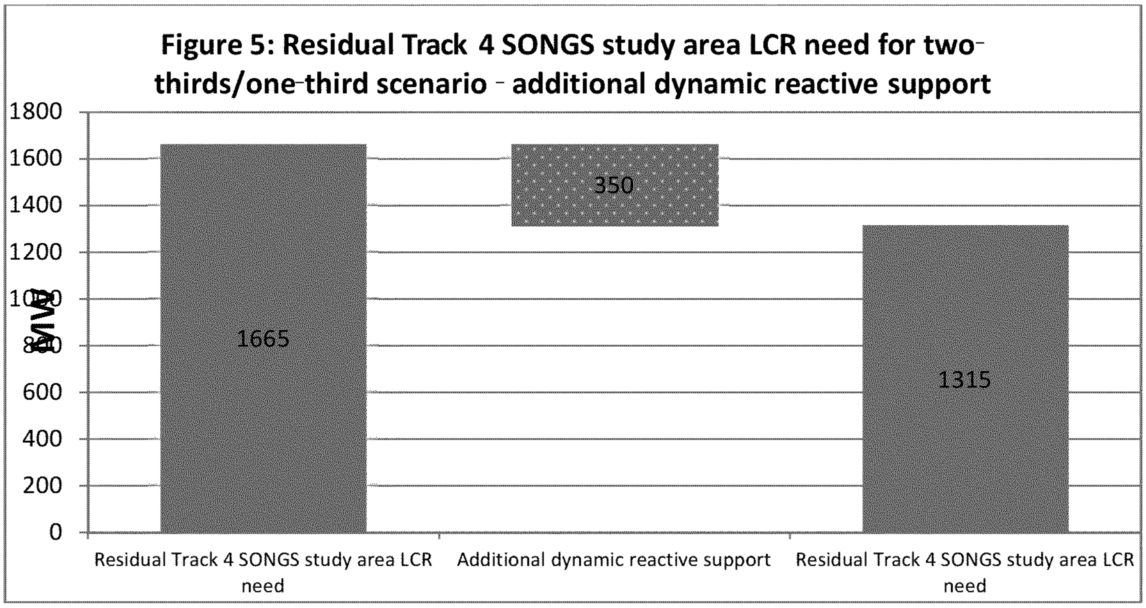
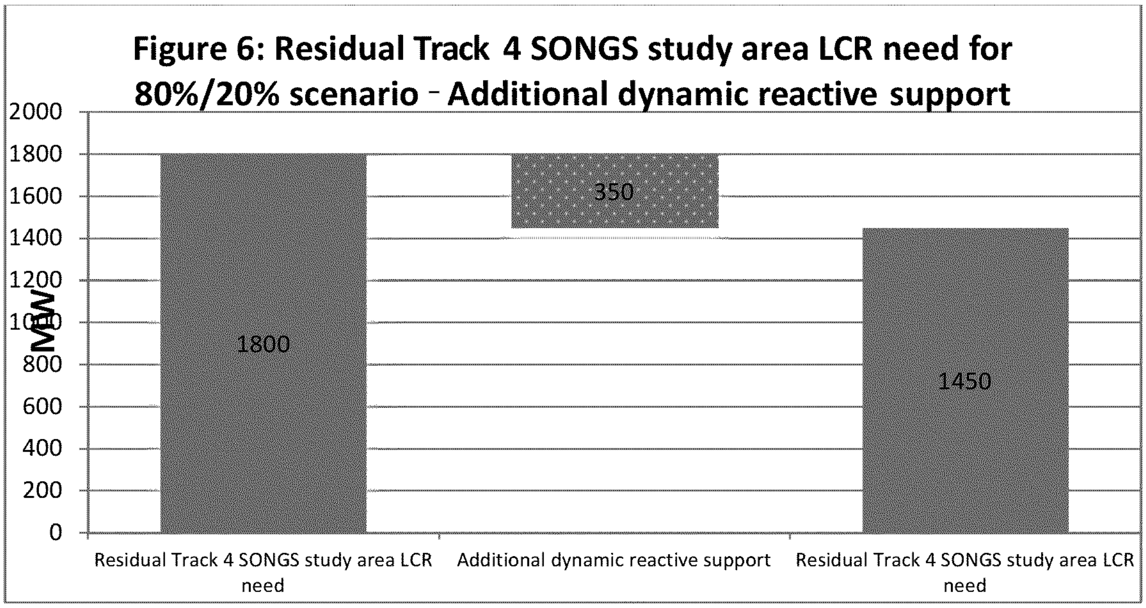
[65] Ex. CAISO 1/ Sparks, p.15: 12-24 in comparison to Ex. SCE 1 p. 27: 6, "All SCE scenarios assume that Projects 1 through 8 are in operation in 2022" and Table III-3.

[66] Ex. CAISO 1/ Sparks, p.15: 12-28.

[67] 2012/13 TPP, p. 185-186, Table 3.5-10, note identifier "#" (p 186) (Appended as Attachment C to Joint Motion,).

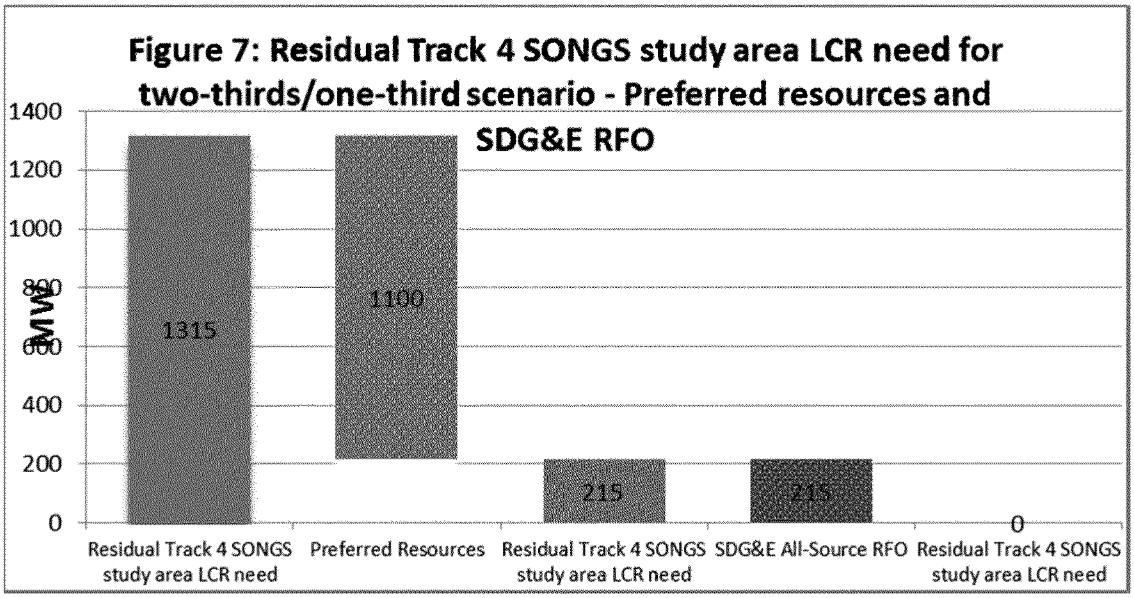
[68] Comments of the California Independent System Operator Corporation Addressing Additional Issues, September 30, 2013, p. 4.

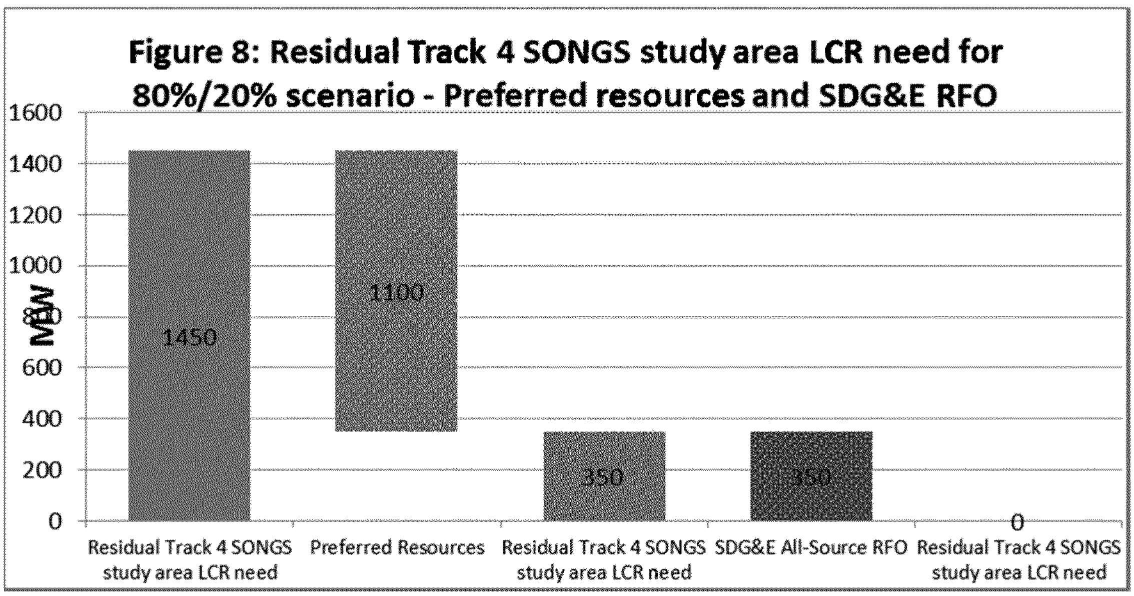




As shown in Figures 5 and 6, this calculation results in a residual need of 1450 MW (assuming that 80% of the resources were located in SCE service territory and 20% in SDG&E service territory) or 1315 MW (assuming that two thirds of the resources were located in SCE service territory and one third in SDG&E service territory).

ORA assumed that not more than 1100 MW of preferred resources would be available to meet need across the entire SONGS study area, thus requiring a range from 215 MW to 350 MW of non-preferred resources (or additional preferred resources beyond those available from the Revised Scoping Memo) to balance the equation. ORA calculated the need that must potentially be filled by non-preferred resources by subtracting 1100 MW of preferred resource potential from the residual SONGS study area need under the two thirds/one third scenario [1315-1100] as well as the 80%/20% scenario[1450 – 1100]. With more resources located in the San Diego service area, a lower total level of resources is required for the entire SONGS study area. With a minimum of 215 MW of all-source resources (incremental to the 1100 MW of preferred resources) placed in the San Diego area, no additional resources are needed in the SONGS study area.





ORA calculated the 1100 MW of available preferred resources by first adding additional preferred resources not modeled pursuant to the Revised Scoping Memo, including approximately 369 MW of incremental energy efficiency (EE),[69] 997 MW of second contingency demand response (DR), and 279 MW of second contingency small photovoltaic (PV),[70] for a total of roughly 1650 MW of EE, DR and small PV. It is reasonable to include these amounts as potential, even though they were not modeled as reducing demand, because they reflect amounts that are available to meet need by 2022 given the right program design.

ORA then subtracted the 550 MW of preferred resources already authorized by D.13-02-015 in order to avoid double counting the potential of preferred resources authorized by that decision.[71] Assuming that 1100 MW of preferred resources are available to meet SONGS study area LCR need yields a residual need of about 350 MW, assuming that 80% of the resources were located in SCE service territory and 20% in SDG&E service territory. Alternatively, if assuming that two-thirds of the resources were located in SCE service territory and one third in SDG&E service territory, there is a shortfall of approximately 215 MW. ORA therefore recommends that the Commission authorize SDG&E to procure between 215 and 350 MW of

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[69] The 369 MW of incremental EE is based on the difference between low and med incremental EE estimates, 100% for San Diego, and 50% for the LA Basin portion of the SCE territory. For San Diego, this is 131 MW (318 mid-case, minus 187 low case); for SCE, it is 238 MW (50% of 1221 MW mid case minus 746 MW low). See *Energy Efficiency Results for a Managed Forecast: Estimates of Incremental Energy Savings Relative to the California Demand Forecast Relative to the California Energy Demand Forecast 2012-2022*, available at http://www.energy.ca.gov/2012_energypolicy/documents/demand-forecast/IUEE-CED2011_results_summary.xls as referenced in footnote 10 at page 4 in Attachment A of the Revised Scoping Memo. Details of this calculation are included in Attachment B to this brief.

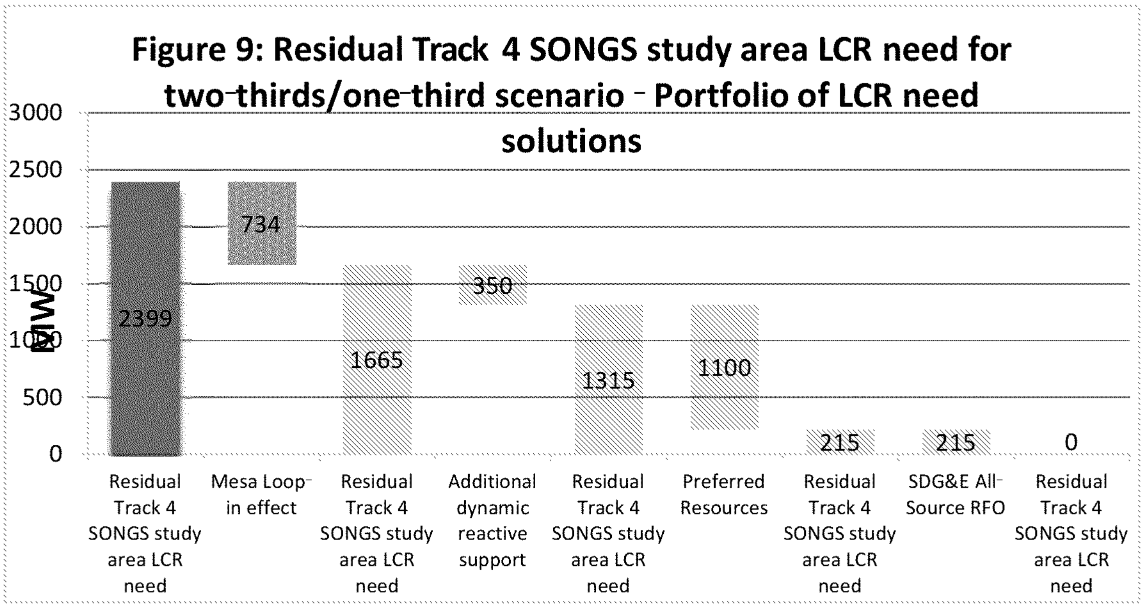
The Revised Scoping Memo used the low level of savings to account for the fact that "future energy efficiency programs are not crafted to specific locations." Revised Scoping Memo, Attachment A, p. 4. However, authorizing SCE to procure 700 MW of preferred resources, including EE, will allow and encourage SCE to target EE programs where they are needed.

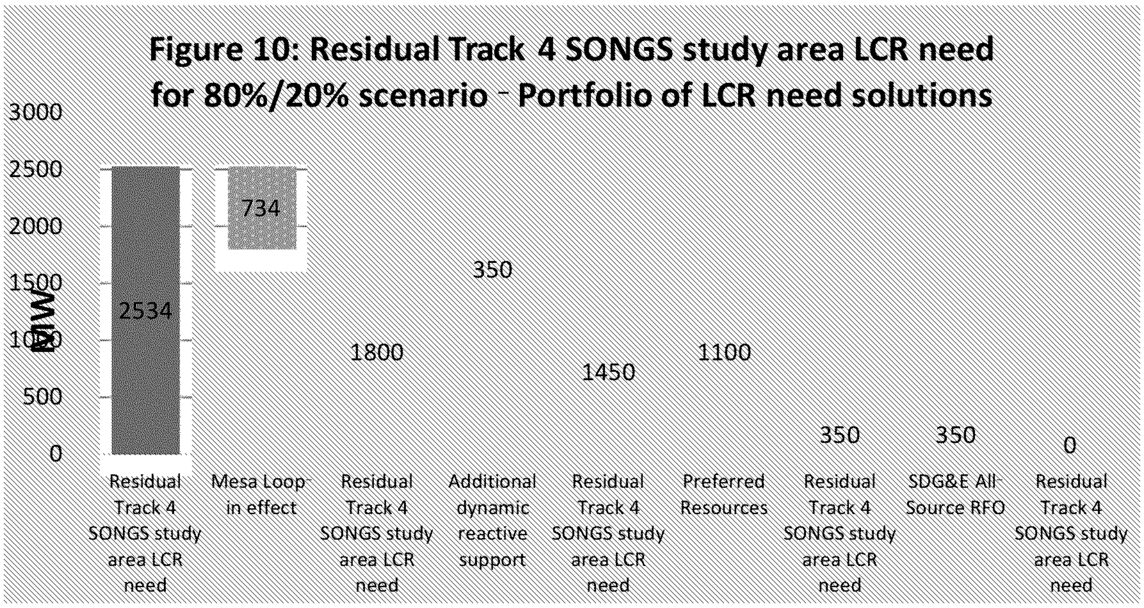
Mr. Martinez for the Natural Resources Defense Council (NRDC),pointed out that the Revised Scoping Memo did not reflect all the energy efficiency savings that can reasonably be expected to occur by 2022. In addition to differences between using the mid and low case savings scenarios, the increased savings (or decreased need) result from including updated California Energy Commission savings for the years 2015 and beyond (157 MW) and including naturally occurring savings (576 MW). Ex. NRDC 1/Martinez (Track 4 Opening Testimony of the Natural Resources Defense Council September 30, 2013), p. 5.

[70] 279 MW of PV capacity is based on 616 MW installed, multiplied by the peak impact factor to arrive at NQC for the PV.

[71] As seen in Ex. SCE 1/Cushnie, p. 56, Table VI-6, 400 MW "additional preferred resources and energy storage" plus 150 MW of preferred resources.

resources in addition to the 400 MW of preferred resources.

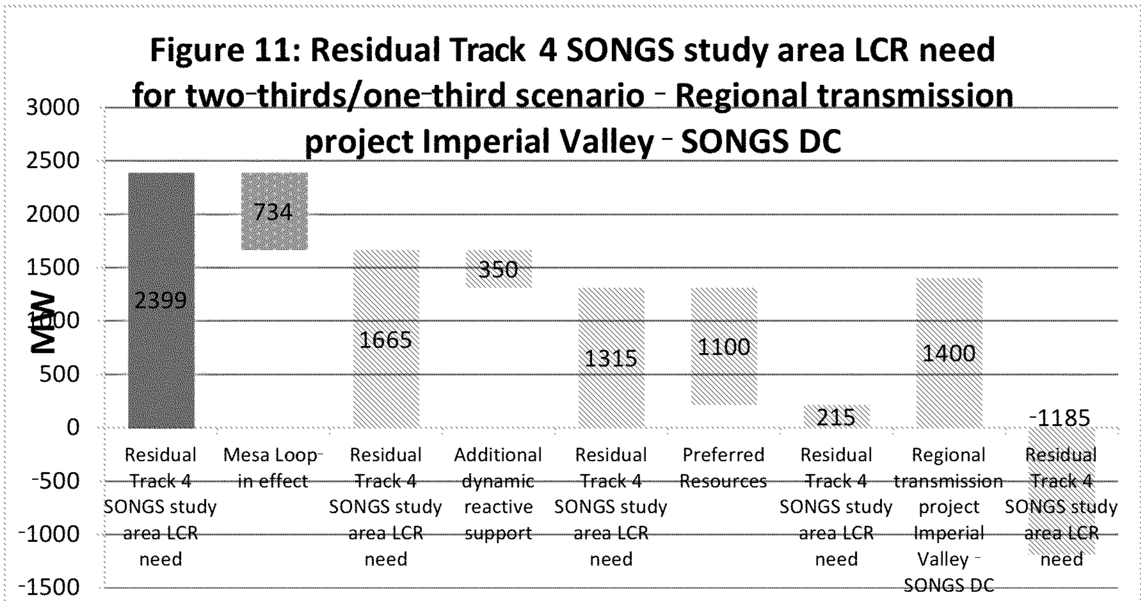




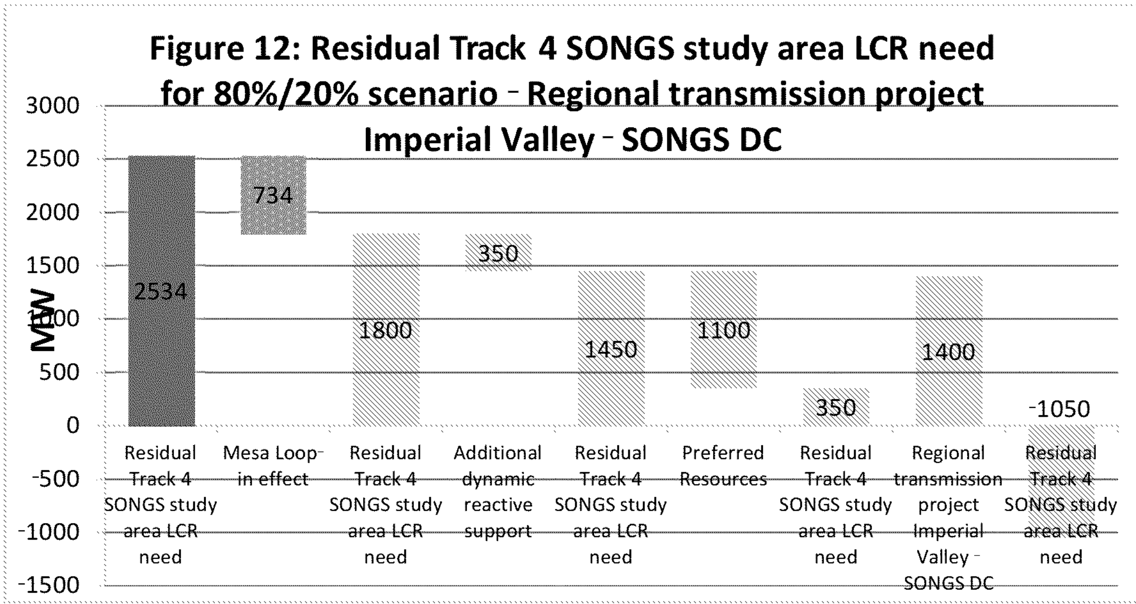
SDG&E found that the Imperial Valley SONGS DC project would reduce LCR need by 1400MW, and that the Devers NCGen AC project would reduce LCR need by 950 MW.[72] SCE found that the Regional Transmission Scenario as modeled lowered LA Basin needs by 408 MW

[72] Ex. SDG&E 3/Jontry, Table 2 at p. 11.

relative to the LA Basin transmission scenario.[73] If the Commission wants to leave open the possibility that i) additional preferred resources will be available beyond those set out in the Revised Scoping Memo, and/or ii) that the 2013 IEPR will reveal the potential for more preferred resources to be available to lower peak load, and/or iii) that the SPS can be used as a "bridge" until new transmission and preferred resources are available, it could eliminate SDG&E's all-source RFO authorization and instead limit procurement options to preferred resources.



[73] Ex. SCE 1/Chinn, p. 38: 14-16.



D. The Commission should update any interim procurement authorization based on the 2013/2014 TPP.

The Commission should revise any interim procurement authorization for incremental need in the SONGS study area once the 2013/2014 TPP results are available. CEERT proposed a feasible schedule that would allow informed decision making about procurement based on the 2013/2014 TPP and a proposed decision in June of 2014.[74] Some variation of this would allow for the possibility of updates. Revising the need (upwards or downwards) based on more accurate information, would allow LCR procurement based on the facts that are more likely to reflect that need that will exist in 2022.

The Commission recognized the importance of revising procurement authorization in D.13-03-029, the decision approving the Escondido PPTA and authorizing SDG&E to procure 298 MW:

> "As discussed above, we no longer find a need for additional resources to meet local and system resource adequacy requirements as soon as 2015. Under all record forecasts, "whether as originally presented by the parties or as adjusted in this decision, there is no need for the new capacity represented by the PPTAs until early 2018, and then only under the assumption that the Encina OTC units retire. It would not be reasonable to pay for that excess capacity for four of the 20 year terms of the PPTAs associated with Pio Pico Energy Center and Quail Brush Energy Center.

[74] See Attachment C to this brief, CEERT's suggested schedule, submitted in its September 10, 2013 Comments of the Center For Energy Efficiency and Renewable Technologies on the Track 4 Schedule.

> Accordingly, we deny approval of the Pio Pico Energy Center and Quail Brush Energy Projects PPTAs."[75]

Here too, if the 2013/2014 TPP results show that the Commission's interim authorization is higher (or lower) than needed, the Commission should adjust the interim authorization accordingly.

E. It is reasonable to rely on preferred resources to meet LCR need given the other options available to maintain reliability if necessary.

California's loading order, established first in the 2003 Energy Action Plan, and reiterated in subsequent Commission decisions,[76] requires the utilities to procure resources in a specific order:[77]

> "The 'loading order' established that the state, in meeting its energy needs, would invest first in energy efficiency and demand-side resources, followed by renewable resources, and only then in clean conventional electricity supply."[78]

Moreover, the Commission authorizes funding for EE, DR, and distributed generation based on their cost-effectiveness.[79] The cost-effectiveness of EE, DR, and other preferred resources is greater when compared to the long-run avoided cost (or the cost of a new resource) as compared to the short run-avoided cost (whole sale energy prices, which for the most part

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[75] D.13-03-029, p.15.

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

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

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

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

reflect the cost of operating an existing resource).[80] Reliance on preferred resources to meet local LCR needs will maximize ratepayers' return on investment in preferred resources, because their investment in programs to comply with California's loading order in that instance would displace the need for new gas-fired generation, thereby realizing the long-run avoided cost.

1. Using preferred resources to meet LCR presents new opportunities.

Relying on preferred resources to meet LCR need is not without challenges. SCE points out that whether or not a specific type of preferred resource can effectively meet LCR need depends on how quickly it can respond to a contingency (assuming it is dispatchable), the preferred resource's availability when it is needed, and the duration of the availability.[81] TURN observes that planning for the widespread use of preferred resources to meet local capacity needs "faces several key uncertainties, particularly as to the quantities that will be available, the ability of these quantities to meet local reliability needs, and the costs of such resources."[82] To address some of these challenges, CAISO has developed a preliminary methodology to assess characteristics preferred resources should possess to address local capacity issues followed by ongoing stakeholder discussions.[83]

SCE discusses its "Preferred Resources 'Living' Pilot Program (Pilot)," for which it is not requesting Commission authorization in this proceeding, as a means "to procure and evaluate the ability of preferred resources to meet LCR needs."[84] SCE explains that while it has procured preferred resources to meet compliance targets such as the 33% Renewables Portfolio Standard (RPS), using preferred resources to meet LCR needs is a new application that must consider "location, timing and duration of energy savings or load reductions."[85] SCE proposes to focus the Pilot on meeting peak loads at the area in Orange County near the Johanna and Santiago

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

[81] Ex. SCE 1/Silsbee at 18:14-19:1.

[82] Ex. TURN 1/Woodruff at 7:9-12.

[83] Ex. ISO 7/Millar, 4:11-18; *see also* Ex. TURN 1, Attachment 6, "Determining an Effective Mix of Non Conventional Solutions to Address Local Needs in the TPP," CAISO Presentation to 2013/2014 Transmission Planning Process Stakeholder Meeting, September 25, 2013.

[84] Ex. SCE 1/Silsbee, p. 49:3-4.

[85] Ex. SCE 1/Silsbee, p. 49:19.

substations, but has no specific MW target for the Pilot.[86] ORA supports the approach outlined for the Pilot, but recommends moving ahead as soon as feasible and

> "recommends annual evaluations to determine the ability to procure these resources in local areas and their reliability in responding to dispatch. An expedited timeframe for such evaluations would be valuable in demonstrating the performance of preferred resources to avoid unnecessary procurement."[87]

Despite the challenges inherent in the use of preferred resources to meet LCR needs, ORA agrees with other parties that the challenges are not insurmountable.[88] Moreover, it does not appear that a minimum level of new gas-fired generation is needed from the standpoint of maintaining system reliability given the SONGS outage.[89] ORA agrees with CAISO witness Mr. Millar's observation that "[t]he CPUC and other state agencies are in a position to ensure that those preferred resources are in fact developed, through the authorization of procurement or other actions, if the need is clearly identified."[90]

2. There are options to maintain reliability in the event that preferred resources do not develop by the date they are needed.

It is important to plan for the possibility that preferred resources do not materialize soon enough or in a sufficient amount, so that there are options available to maintain reliability. Fortunately, there are several possibilities available in the event that preferred resources are not available when they are needed.

a) Limited extension of some units of a once-through cooling (OTC) plant

The Clean Water Act section 316(b)[91] requires that the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing

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[86] Ex. SCE 1/Silsbee, p. 49:5 – 50:12.

[87] Ex. ORA 2/Ciupagea, 6:14-22.

[88] Mr. Millar testified for the CAISO that "We are optimistic that we can work with industry to include and further advance preferred resources in meeting local needs." RT 1608:15-17. See also RT 1640:8-12.

[89] RT 2013:22-2014:1, SCE/Chinn. ("from a transmission planning perspective, I guess I don't have a particular opinion what the makeup of the resource is.")

[90] Ex. ISO 7/Millar, 3:16-18; see also RT 1635:17-19, ISO/Millar (expressing optimism that one thousand megawatts of need can be met through preferred resources.)

[91] 33 U.S.C. § 1326(b).

adverse environmental impact. To implement this statute, in 2010 the State Water Resources Control Board (SWRCB) adopted the "Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (Policy)."[92] California state agencies, including the Commission, are planning to meet the OTC plant retirement deadlines in compliance with this policy. In fact, most of the OTC units in southern California are scheduled to retire between 2017 and 2020, and the permanent closure of SONGS occurred in advance of its scheduled OTC retirement date of December 31, 2022.[93] Notwithstanding California's commitment to meeting OTC compliance deadliness, the Commission should consider that limited extensions to OTC compliance deadlines of the most electrically effective OTC plant(s) may be available if needed to bridge a short-term gap between when resources are needed, and when they are available.

The *Preliminary Reliability Plan for LA Basin and San Diego* (Draft Preliminary Reliability Plan), issued on August 30, 2013, by the California Energy Commission, the Commission and the CAISO, recognized that "[e]xtension to the OTC compliance dates, in part or whole, may be necessary in order for replacement resources (both preferred and conventional) to be developed or procured and achieve operation, without unduly limiting procurement options."[94] Relaxation of hard compliance deadlines for local OTC units is consistent with the SWRCB's *Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling* (OTC Policy). The SWRCB's OTC Policy allows for two types of temporary suspension of OTC units: less than 90 days or more than 90 days for existing OTC power plants within CAISO's jurisdiction if "CAISO determines that continued operation of an existing power plant is necessary to maintain the reliability of the electric system..."[95]

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[92] The preferred method of compliance is to reduce a unit's water intake by 93% by replacing an existing unit with a newer, more efficient plant with a closed cycle, wet cooling system. If a generator is unable to employ this method, then, with the SWRCB's permission, it may retrofit existing units by improving the technology to reduce the intake of water by 83.7%. Plants using OTC must either comply or retire. *See Statewide Water Quality Control Policy On The Use Of Coastal And Estuarine Waters For Power Plant Cooling*, p. 4, available at http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/docs/policy100110.pdf

[93] *Once-Through Cooling Policy Protects Marine Life And Insures Electric Grid Reliability, p. 2, available* at www.waterboards.ca.gov/publications.../oncethroughcooling.pdf p. 2.

[94] Ex. ORA 5,/Rogers, Attachment A, p. 8.

[95] Ex. ORA 5/Rogers, Attachment B, Statewide Water Quality Control *Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling*, as amended July 19, 2011, p. 6-7.

Mr. Millar of the CAISO testified:

> "it is reasonable to explore OTC compliance delays if the timing alone would otherwise lead to a less ideal long term solution strictly due to slight differences in implementation timelines for preferred alternatives that could include DR, energy efficiency, storage or transmission."[96]

ORA agrees and recommends that the Commission support a process that would include stakeholders and regulatory agencies working together to consider modifications to current OTC compliance deadlines as a potential interim solution for any Track 4 need.

b) Special Protection System as a bridge

Currently, SDG&E has a Special Protection System (SPS) in place to protect grid integrity in the event a G-1/N-1-1 contingency. SDG&E relies on the SPS when the largest generator is already out of service. CAISO notes that this "safety net" can be used for Category D conditions (i.e., simultaneous loss of both 500 kV lines).[97] WECC certified this SPS in July 2013. [98] It is an important tool in addressing the absence of SONGS. [99] Section IV G of this brief discusses factors that the Commission should consider in deciding whether to use an SPS as a long-term mitigation strategy, a topic that was the subject of extensive testimony, cross examination and debate.

Less controversial is whether the Commission should consider the use of an existing SPS as an interim solution to support the development of resources that might not be ready at the precise time they are needed. Mr. Fagan testified for ORA that "the SPS could serve as a cost-avoidance measure to bridge the gap between when need is first seen, and when preferred resources (and/or transmission) come online."[100] Mr. Millar of the CAISO testified that he agreed with this approach, noting that the CAISO's practice had been to allow load shedding for Category C contingencies such as the one at issue here "only for interim periods while mitigation

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[96] Ex. ISO 7/Millar, p. 7:15-18.

[97] Ex. ISO 2/Sparks, p. 7: 17-28.

[98] RT 1703:23-26, SDG&E/Jontry.

[99] RT 1721:1-3, SDG&E/Jontry (the SPS is "basically our operating standard right now because of SONGS permanent retirement.")

[100] Ex. ORA 3/Fagan, p. 11: 22 – 27.

is being deployed and as a last resort."[101] Mr. Sparks of the CAISO testified that "interim" could mean as long as ten years, depending on the ultimate solution.[102] Mr. Jontry testified that SDG&E supports use of load shed as interim solution until a permanent solution is in place, "either additional resources, generation or preferred resources or [a] transmission upgrade."[103]

ORA agrees that the Commission's objective should be to get "the best overall solution implemented as quickly as possible and keep the interim period to a minimum."[104] For that reason, as explained below, the Commission should ensure that SCE and SDG&E provide clear concise plans for meeting preferred resources goals, with milestones to measure achievement.

c) Local generation development reserves

Local generation development reserves (ORA's term for the concepts reflected in SCE's proposed contingent site development[105] and SDG&E's proposed energy park)[106] offer the possibility for SCE and SDG&E to develop gas-fired generation or other resources in a shorter time frame (less than seven years) to meet local reliability needs. This concept ensures that generation would be available in the event that anticipated preferred resources and transmission solutions used for LCR needs, do not develop in time. SCE proposes to develop generation sites near the Johanna and Santiago substations by obtaining the necessary site and development permits for use of these reserve areas by third party developers as a backup for SCE's Preferred Living Resources Pilot.[107] Mr. Rumble states that SCE would seek Commission approval before any generation is built.[108]

SDG&E is currently exploring the feasibility of developing an energy park to be used to meet future local resource need with the goal of reducing the time currently needed between identifying a "finding of generation need and the in-service date of generating plants necessary to

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[101] Ex. ISO 7/Millar, p. 11:25-12:3.

[102] RT 1412:19, Sparks/ISO.

[103] RT 1710:17-27, Jontry/SDG&E.

[104] RT 1615:2-5, ISO/Millar.

[105] Ex. SCE 1/Rumble, pp. 61-62.

[106] Ex. SDG&E 1/Anderson, pp.16-17.

[107] Ex SCE 1/Rumble, p. 61:3-8.

[108] Ex. SCE 1/Rumble, p. 62:1 – 5.

meet that need."[109] The proposed energy park would consist of "lots" that would be made available in future RFOs solicitations to independent generators as part of a fully-licensed park with necessary transmission and gas infrastructure as well as access to water. Mr. Anderson states that SDG&E would file a separate application with the Commission before moving forward with the energy park proposal.[110]

These proposals offer the potential to backstop preferred resources and transmission solutions, allowing them to develop to meet LCR need by alleviating the pressure to build gas-fired generation seven to nine years in advance of when it is needed. In addition, the potential availability of more sites for gas fired generation, should they be necessary, provides an option to mitigate market power given the limited availability of sites in the SONGS study area.[111] If the utilities can work with state regulatory agencies to establish a process that allows for staged approval, then investing in local generation development reserves now for use at some point in the future would be a reasonable hedge against unforeseen local reliability issues and just-in time procurement.

d) Contingent contracts

SCE proposes another form of back stop: option contracts with third party developers that reduce the development and procurement lead-time of gas fired generation by two years.[112] SCE would bilaterally negotiate these options contracts and require "the seller to perform the necessary pre-development work to site, permit, and construct a specified GFG resource…"[113] Although option contracts could conceivably be used to back stop the development of preferred resources , ORA does not support this option. Although it is difficult to predict the costs for this type of contract, SCE witness Mr. Cushnie estimated that the cost could range from two or three million dollars to tens of millions of dollars for a single contract.[114] In contrast to the local

[109] Ex. SDG&E 1/Anderson, p. 16: 19 – 20.

[110] Ex. SDG&E 1/Anderson, p. 17:8-10.

[111] Mr. Rumble testified for SCE that contingent sites operate to increase competition for new gas fired generation because they allow independent power producers with site control to submit proposals for new gas fired generation. Ex. SCE 2/Rumble, p. 32:10-13.

[112] Ex. SCE 1/Cushnie, pp. 58:20-59:1; 61: 4 – 6.

[113] Ex. SCE 1/Cushnie, pp. 58:12-23.

[114] RT 1966:9-10, SCE/Cushnie.

generation development reserves, which offer the potential for ratepayers to invest in an asset that will be available when needed, the option contracts would represent a very expensive insurance policy. Option contracts are therefore the least attractive option to back stop preferred or other resources.[115]

F. The Commission should allow SCE and SDG&E to procure preferred resources in the manner that they recommend, as long as they meet their goals.

If the Commission authorizes SCE and SDG&E to procure preferred resources as ORA recommends, then it should direct each utility to submit a procurement plan explaining how it plans to accomplish the procurement of preferred resources, including proposed milestones and evaluation dates, and detailed proposals to back stop the procurement. The plans should explain how the totality of the contracts or programs are cost effective and consistent with the loading order, including a demonstration that each utility has assessed the availability, economics and viability of the preferred resources in meeting LCR need. The plans should demonstrate technological neutrality, so that no resource was prevented from the solicitation process, although SCE and SDG&E may include proposals to solicit preferred resources through different avenues.

The plans should demonstrate integration with the storage goals adopted in D.13-10-040, which requires SCE to obtain 580 MW and SDG&E 165 MW of energy storage by 2020.[116] The utilities' plans should demonstrate that 1) the utility will optimize its LCR procurement in order to minimize over-procurement of resources, and 2) that the procurement of energy storage resources will meet identified needs in the LTPP proceeding in order to maximize the value for ratepayers and avoid the procurement of redundant conventional generation resources. In other words, energy storage procurement should be least-cost best-fit, tailored according to LCR and operational flexibility needs identified in LTPP, and counted towards meeting the load serving entities (LSE's) resource adequacy (RA) requirements.[117]

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[115] Mr. Cushnie explained that SCE envisioned the option contracts as a back stop for the proposed Mesa Loop-In project and contingent siting proposal was for the Pilot program. RT 2066:16-20.

[116] D.13-10-040, p. 2 and Conclusion of Law 41 at p. 76 (It is reasonable to require the utilities to contract for their storage targets by no later than 2020, with installation and operation of a total of 1,325 MW across all utilities installed and operational by no later than the end of 2024).

[117] Ex. ORA 2/Ciupagea, pp. 7: 26 – 8: 5.

SCE may choose to expand its Preferred Living Resources Pilot proposal and SDG&E may choose to implement a similar preferred resources pilot. The utilities may also elect to obtain some preferred resources from expansion of their existing programs. The Commission should allow reasonable approaches that appear likely to succeed, based on the plans SCE and SDG&E submit.

G. Decisions regarding service reliability should be based on a reasonable record relating to costs, benefits, risks and affordability.

The CAISO, SCE and SDG&E calculate the LCR need for the SONGS study area using different approaches to acceptable mitigation strategies for the limiting N-1-1 contingency consisting of the sequential loss of the ECO-Miguel section of the Southwest Powerlink 500 kV line and the Ocotillo Express-Suncrest section of the Sunrise Powerlink. The CAISO excludes the effect of the potential use of an SPS and instead assumes that new resources are needed to resolve the contingency.[118] SDG&E acknowledges the presence of a WECC-approved SPS for the G-1/N-1-1 contingency but does not directly include the effect of the SPS when considering the range of need for the N-1-1 contingency.[119] SDG&E and CAISO assume new generation resources (and/or transmission solutions) are needed to resolve the contingency. SCE calculates LCR need assuming the SPS is available to mitigate the limiting contingency, but then requests additional procurement authority in recognition of the fact that CAISO does not allow reliance on this SPS for long-term planning.[120]

The use of an SPS to mitigate the N-1-1 contingency makes a significant difference in the determination of need. Reliance on the existing SPS for relevant N-1-1 conditions[121] would decrease SCE's need for new generation by 438 MW in the all generation scenario.[122] The effectiveness of the Mesa Loop-In in reducing the need for new generation decreases from 1200

[118] Ex. ORA 3/Fagan, Attachment B (CAISO Data Request Response 2).

[119] Ex. SDG&E 3/Jontry, p. 7.

[120] Ex. SCE 1/Chinn pp. 6-7.

[121] As noted by Mr. Fagan (RT 1835-1836) using the SPS to shed load would only be necessary if the relevant conditions occurred simultaneously – very high peak load, and loss of both 500 kV lines. Its consideration in the planning stages does not imply deployment in operation.

[122] Ex. SCE 1/Chinn, p. 32, Table III-5.

MW to 734 MW without load shedding.[123] Mr. Jontry testified for SDG&E that reliance on the SPS would decrease the need for new generation by approximately 1000 MW,[124] although he later revised that amount to 150 MW to account for a new study and the installation of more reactive resources.[125] In fact, Mr. Jontry's downward adjustment for the amount of new generation that could be avoided based on the SPS compared the N-1-1 contingency to the G-1/N-1 contingency. The correct comparison would be N-1-1 with and without load shedding, a number that is not currently in the record.

The amount of new generation that reliance on the SPS could displace ranges from more than 500 MW (assuming 438 MW for SCE's all generation scenario and 150 MW for SDG&E's generation only scenario as claimed in Mr. Jontry's rebuttal testimony) to 900 MW under SCE's LA Basin Transmission and Preferred Resources scenarios.[126] Mr. Fagan testified for ORA the estimated the cost of new gas fired generation ranged from $595 million (436 MW) to $1.36 billion (1,000 MW) using $1,363/kW as the installed capital cost for a combustion turbine.[127] Mr. Woodruff estimated for TURN that the cost of SCE's Preferred Resource scenario appears $595.5 million higher in the absence of using a load-shedding SPS as part of a contingency mitigation plan.[128]

Despite the significant cost of excluding reliance on an SPS as potential option to resolve the limiting contingency, support for the recommendation not to consider the SPS is largely limited to qualitative description of possible consequences. Mr. Sparks testified for the CAISO that the area of potential load shedding is "an urban high population density load area" with lines that have "high exposure to outages."[129] The Imperial Valley substation is a critical overlapping substation; its outage would adversely impact SDG&E, and two other utilities.[130] Mr. Jontry of

[123] Ex. SCE 1/Chinn, p. 37:14-17.

[124] Ex. SDG&E 3/Jontry, p.7 11 – 13.

[125] RT 1714: 25 – 1715: 15; Ex. SDG&E 4/Jontry, pp. 2-3.

[126] Ex. TURN 1/Woodruff, Table 4, p. 17.

[127] Ex. ORA 3/Fagan p. 7: 4 – 8.

[128] Ex. TURN 1/Woodruff, Table 4, p. 17.

[129] Ex. ISO 2/Sparks, p. 5:25-26.

[130] Ex. ISO 2/Sparks, p. 5:25-26.

SDG&E cautioned against the "potentially severe economic and civil consequences"[131] that might result from controlled load shedding. These are significant factors to consider, but neither the CAISO[132] nor SDG&E[133] conducted studies to compare the cost or risk of relying on its SPS versus the costs of other resources to mitigate the critical contingency.

Deciding what mitigation to implement might in some cases involve review of the costs and benefits of various solutions—new generation, new transmission and reliance on the SPS. Currently, the SPS is already in place for N-2 contingencies[134] (e.g. the simultaneous loss of the Sunrise and Southwest power links), so the cost to consider does not include the cost of its implementation. Instead, the analysis should consider the cost of relying on the SPS rather than another alternative, or the consequences that might result if the N-1-1 contingency occurred in the absence of new generation or transmission solutions. In trying to estimate the potential consequences, relevant factors include how often the contingency is likely to occur, the likelihood that the contingency would occur when there were not adequate resources to serve load in the event one of the lines went down, and a range of costs of not serving load. As Mr. Fagan explained, the SPS might never be used.[135]

Little of the information needed to make such a reasoned decision is in the record. Mr. Sparks testified that the risk of a fire in the area of the lines was once every thirteen years, although the report on which he relied indicated that the interval might be longer.[136] Mr. Fagan noted that CAISO's own load duration curves for the SONGS area showed that problematic peak loading periods occur for less than 2.5% of summer hours.[137] No party even attempted to estimate the probability that two sets of low probability events – i.e., very high peak load and

[131] Ex. SDG&E 4/Jontry, p. 2:19.

[132] RT 1843:3-17,ORA/Fagan.

[133] Ex. ORA 3/Fagan, Attachment D SDG&E response to DRA-Sierra Club- CEJA data request second set, question 2. ("SDG&E has not conducted any studies quantifying the cost effectiveness of load-shedding versus new in-basin generation resources.")

[134] Ex. CAISO 2/ Sparks (Rebuttal Testimony of Robert Sparks on behalf of the California Independent System Operator Corporation), 7: 17-28.

[135] RT 1837:17-23,ORA/Fagan.

[136] Ex. ISO 2/Sparks, p .5: 26 – 6:1; *See* Ex. TURN x ISO 7, p.56 ("The calculated MTBF [mean time between failures] range of 28 to 928 [years]still holds true for the alternate path."); cf. Ex. TURN x ISO2, p. 3 ("The estimated MTBF for the lines is in the range of 21 to 928 years.")

[137] Ex. ORA3/ Fagan p. 9: 13 -24.

loss of both 500 kV lines in sequence – would occur at the same time on the same day. Mr. Monson testified for the Independent Energy Producers Association that loss of service would result in costs including "spoilage, lost production time, and lost sales" as well as well possible traffic accidents and medical problems.[138] The costs of curtailment of firm load "depend on the frequency and duration of curtailments, the amount of capacity curtailed, and the value of service for customers," information that is not in the record.[139]

Mr. Sparks testified that the cost benefit analysis in the ISO standards were typically used for "a fairly simplistic type of analysis for a simple system…" rather than the relatively large, complex one at issue in this case.[140] Mr. Sparks further explained that "[t]here isn't a set of commercially available tools that can be used to perform…" this type of quantitative analysis.[141] Mr. Millar testified for the CAISO that "we don't believe this circumstance is one where a straightforward cost benefit analysis is an effective consideration."[142] Although the circumstances of this case pose challenges in attempting to quantify the risk and cost of relying on the SPS, the Commission's decision-making process would benefit from more information, including perhaps a range of scenarios to illustrate the potential cost and risk of relying on the SPS.

The CAISO is responsible for operating the transmission grid used by SCE, PG&E, and SDG&E "consistent with achievement of planning and reserve criteria no less stringent than those established by the Western Electricity Coordinating Council and the North American Reliability [Corporation]."[143] The Commission is responsible for service reliability and maintaining reasonable rates, and has rejected the notion of "reliability at any cost," indicating instead that "measures that are proposed to promote greater grid reliability should be evaluated

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[138] Ex. IEP 2/Monsen, p.15:12-16.

[139] Ex. IEP 2/Monsen, p.15:22-16:1.

[140] RT 1432:16—1434:10, ISO/Sparks.

[141] RT 1435:20-23, ISO/Sparks.

[142] RT 1613:9-12, ISO/Millar; see also RT 1622:1-6 appropriate use of cost benefit information refers to "circumstances lending themselves to producing a meaningful result that can be effectively taken into account by a decision maker in weighing the costs against the calculation benefits of mitigating against the large outage.

[143] Public Utilities Code Section 345.

by weighing their expected costs against the value of their expected contribution to reliability…"[144]

As explained above, ORA is not recommending long-term reliance on an SPS to resolve LCR need related to the retirement of SONGS. Nevertheless ORA agrees with SCE that:

> "to the extent that specific general and/or localized criteria are adopted to avoid load shedding for Category C contingencies, the costs and benefits of such criteria should be comprehensively evaluated and reasonable time lines for implementation of required system changes should be adopted."[145]

ORA therefore supports an open and informed discussion of the costs, benefits, and affordability of a standard that exceeds NERC, WECC, and the CAISO's own written standards.[146]

H. The Commission should allocate Track 4 LCR costs to all benefitting customers in the SONGS study area, including bundled customers, direct access (DA) customers and Community Choice Aggregation (CCA) customers.

The net capacity costs of all Track 4 LCR procurement should be allocated to all benefitting customers in the SONGS study area, including bundled customers, direct access (DA) customers and Community Choice Aggregation (CCA) customers.[147] Since LCR resources to replace SONGS would provide reliability benefits to all customers, the net capacity costs should similarly be allocated to all customers. Allocating the cost of resources that will enhance system reliability is consistent with Public Utilities Code Section 365.1(c)(2)(A), which provides that if the Commission determines that generation resources "are needed to meet system or local reliability needs for the benefit of all customers in the electrical corporation's distribution service territory," then:

> [T]he net capacity costs of those generation resources are allocated on a fully nonbypassable basis consistent with departing load provisions as determined by the commission, to all of the following:
> (i) Bundled service customers of the electrical corporation.

[144] D.05-10-042, p. 7.

[145] Ex. SCE 2/Chinn, p. 15:8-11.

[146] Ex. TURN 1/Woodruff, p. 27:7-13; Ex. ISO 7/Millar, p. 10: 10:3-6 ("the ISO agrees that to ensure greater transparency, it would be best if practices related to Category C contingencies are addressed as well in the ISO planning standard and intends to conduct an open stakeholder process to augment its planning standards the first half of 2014.")

[147] Ex. SCE 1 /Cushnie, pp. 59-60; Ex. TURN 1 /Woodruff, p. 2:13-14,

(ii) Customers that purchase electricity through a direct transaction
with other providers.
(iii) Customers of community choice aggregators.[148]

ORA agrees that bundled customers do not have an obligation to replace LCR assets in perpetuity,[149] and that the Commission should therefore authorize SCE and SDG&E to allocate Track 4 procurement costs using the Cost Allocation Mechanism (CAM).

V. CONCLUSION

ORA recommends that the Commission authorize incremental procurement for the SONGS study area using the best available information about likely solutions to reduce LCR need, and that in determining need, the Commission consider both service reliability and just and reasonable rates.

Respectfully submitted,

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

[149] Ex. TURN 2/Woodruff, p.9; Ex. SCE 2/Cushnie, p. 40 (rejecting the argument that "an LSE is indefinitely responsible for replacing a retired resource that it owns or controls that is determined to have contributed to grid reliability.")