FILED
07-13-12
04:59 PM

BEFORE THE PUBLIC UTILITIES COMMISSION OF
THE STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U 902 E)for Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center and Quail Brush Power.	A.11-05-023 (Filed on May 19, 2011)

OPENING BRIEF
OF THE DIVISION OF RATEPAYER ADVOCATES

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July 13, 2012

585319

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In this proceeding, San Diego Gas & Electric Company (SDG&E) asks the Commission to determine the local capacity requirements (LCR) in the San Diego area through 2020 and to find a deficit exists in local resources available to meet the LCR needs arises starting in 2018 (following the retirement of the Encina power plant).[1] SDG&E requests that the Commission:

(1) approve the three Purchase Power Tolling Agreements for 450 MW of new conventional generation in the San Diego area, which were originally submitted in application A.11-05-023. Approval would authorize commercial operations at three new facilities, Wellhead Escondido (estimated January, 2014 online date), Quail Brush (June, 2014) , and Pio Pico (May, 2041);[2] and

(2) authorize SDG&E to procure approximately 200 MW of additional new local generation 2020 by issuing a Request for Offers (RFO) at the conclusion of this proceeding.[3]

[1] Ex. 11 at Table 1, RA-5 (Anderson Supplemental Testimony).

[2] See Ex. 4 at 3-4 (DRA Testimony) (summarizing three PPTA projects), Ex. 13 at JE-3:22 (Eekhout Supplemental Testimony).

[3] Trx. Vol. 2 267:19-270:2 (SDG&E Witness Anderson).

The issue of how authorizing long-term procurement for local areas is a novel question for the Commission. It marks a departure from the Commission's historic long-term planning process, which looked at system-wide resources needed to meet average (1-in-2 year) energy demands, taking into account a 15-17% planning reserve margin.[4] Here, the Commission is asked to approve new generation based the CAISO's 2011-2012 transmission plan, which included results from the CAISO's first-ever long-term study using power flow modeling to assess LCR needs (the CAISO's Once Through Cooling, or OTC study). SDG&E also asks the Commission to authorize new facilities based on its "updated" LCR needs analysis submitted in its April, 2012 Supplemental Testimony. This marks a departure from past role of LCR studies, which have been conducted by the CAISO on a year-ahead basis and used in the Resource Adequacy program to determine the Investor Owned Utilities (IOUs) procurement obligations for the next Resource Adequacy compliance year.

At its core, this case asks the Commission to determine how much generation SDG&E's ratepayers should fund to replace reliability "insurance" that is currently provided by the existing Encina power plant. This case is not about meeting average energy needs in San Diego. The need estimates use forecasts of extreme contingency conditions in 2021—a 1-day in 10-year weather event coupled with the loss of two major transmission elements (the largest generator and/or the transmission lines importing power into San Diego). But the results of these studies will indisputably change with time with changes in the location and amounts of load and generation and future transmission system upgrades, and will become better informed in the next few years as California continues to implement its extensive and progressive energy and demand-reduction programs.

Key issues regarding the appropriate way to assess long-term LCR needs are also being litigated concurrently in both this proceeding and the 2012 Long Term Procurement Planning (LTPP) proceeding, R.12-03-014. Overlapping issues include how to account for the CAISO's 2021 studies of local capacity needs. This is a critical issue because the CAISO disregards California's loading order by excluding any future energy efficiency measures and all demand response from its forecast. Similarly, although SDG&E does not disregard demand reduction

[4] See Ex. 16 at 6-8 (Spencer Supplemental Testimony).

measures entirely, it asks the Commission to discount benefits from energy efficiency, demand response, and additional renewable resources including distributed generation. In essence, SDG&E seeks to rely on nothing but "high probability" resources — but this is to meet a low probability contingency event.

Given the uncertainties and novelty of these issues, the Commission should proceed with caution when approving local generation within San Diego to prepare for compliance with State regulations requiring the retirement of Once Through Cooling (OTC) resources. At the very least, the Commission should heed statutory requirements including the loading order and the Commission's duty to ensure just and reasonable rates.

The loading order requires that utilities fill unmet energy needs first through energy efficiency and other demand reduction measures, then through renewable resources (including distributed generation), and finally by looking to conventional generation (such as the three Power Purchase Tolling Agreements (PPTAs) that SDG&E seeks approval for through this application. There is no express exception in the loading order for local area needs. Nor would it make sense to create such an exception for the San Diego load pocket. Energy efficiency and demand response act to reduce demand — and in SDG&E's service territory, the majority of demand occurs within the load pocket. The Commission also has a statutory duty to ensure just and reasonable rates. Using overly-conservative estimates of supply and demand together with conservative transmission planning criteria increases the risks that ratepayers will fund over-procurement of plants that are rarely, if ever, needed.

Looking at the range of uncertainties and balancing potential needs against risks of over-procurement, the record demonstrates that the Commission should not approve all three PPTAs. But if the Commission does approve the PPTAs, it should not grant SDG&E any further procurement authorization in this proceeding. It should defer this issue for re-assessment following the Commission's final decisions on the LCR and system-wide flexibility needs from the 2012 LTPP

SUMMARY OF DRA'S RECOMMENDATIONS

1. DRA recommends that the Commission find the need for new resources is 45 MW in 2020. This is based on DRA's assessments of the range of options expected to reduce the LCR need in 2020, including demand side reductions and transmission planning alternatives

that can be used to ensure reliable grid operations in the event of extreme contingencies (a 1-in-10 year weather event with the loss of two transmission elements). DRA's brief explains why the Commission should not adopt the results of SDG&E or the CAISO's LCR analyses. Thus, the Commission should approve the Wellhead Escondido PPTA (45 MW).

2. If, however, the Commission determines there is additional need beyond 45 MW for local conventional resources by 2020, the authorization should be tailored to fit ─ and not exceed ─ the potential need. Accordingly, the Commission should approve the smallest total amount of PPTA resources that it finds is needed in 2020.

a. If the Commission finds a need of 145 MW or less, it should only approve the Quail Brush PTTA (100 MW) with the Wellhead PPTA (45 MW).

b. If the Commission finds the need is between 145 and 350 MW, it should only approve the Pio Pico PPTA (305 MW) with the Wellhead PPTA (45 MW).

c. If the Commission finds the potential need in 2020 exceeds 450 MW, it should not authorize SDG&E to conduct any additional procurement at this time but should instead defer this issue to the 2012 (or later) LTPP.

3. The Commission should not authorize further procurement to fill a potential residual local need until <u>after</u> the Commission issues decisions that clarify the amounts and attributes of resources needed to support system flexibility needs, so that the procurement can be conducted in a manner that most efficiently meets <u>both</u> types of needs.

4. The Commission also should not authorize further procurement to fill a potential residual local need until after decisions issue from the 2012 LTPP about updated planning assumptions and whether (and how) to adjust the CAISO OTC studies to account for energy efficiency and demand response.

5. If the Commission finds a need for the PPTAs starting in 2018, it should condition approval of the PPTAs on SDG&E's agreement to protect ratepayers in the event that the Quail Brush and/or Pio Pico projects are not fully deliverable (and thus not fully counted towards local capacity requirements) for any period of time. Accordingly, the Commission should either:

a. Order SDG&E to delay the online dates of the Quail Brush and Pio Pico PPTAs until all transmission system upgrades that the CAISO has determined may be necessary to ensure their full deliverability (beyond network upgrades funded through the interconnection costs) will be completed prior to the commercial operation dates of the projects, or

b. Order that SDG&E's shareholders, not ratepayers, fund the replacement value of any local RA needed during any time period in which the projects are not deemed fully deliverable because of additional transmission upgrades that are needed.

ARGUMENT

DRA's Testimony demonstrates that under a range of reasonable assumptions, SDG&E has, at most, a need for the Wellhead PPTA.[5] DRA's estimates are based on SDG&E's and the CAISO's estimates of need with adjustments to account for reasonable assumptions about: energy demand (i.e. load), incremental savings from future energy efficiency measures (uncommitted energy efficiency), expected savings from demand response, and other preferred resources such as distributed generation, additional renewable resources, and combined heat and power (CHP). On the other hand, DRA's testimony also demonstrates that even without the PPTAs, SDG&E could have an excess of local resources in 2020 due to demand reduction measures and distributed generation. That would result in unnecessary and costly over-procurement if the Commission approves all three contracts.

The CAISO and SDG&E LCR studies also disregarded future transmission upgrades and Special Protection Systems (SPS) based on controlled load drop that could maintain grid reliability in the event of extreme multiple contingencies. SDG&E has previously argued that the CAISO should account for SPS to reduce its near-term (2013) local capacity requirements—but it ignores this potential tool for the 2020 planning horizon. Including these measures in the transmission planning process yields another alternative that could reduce the need for the three PPTAs or additional local conventional generation. Accounting for an SPS would also create

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[5] Ex. 15 at 8, Table FG-1 (Ghazzagh Supplemental Testimony) and Ex. 28 (Table FG-1 Expanded); Ex. 17 at 12, Table RF-3 (Fagan Supplemental Testimony).

headroom that would allow the Commission to gain further data over the next few years on whether the expected benefits from substantial ratepayer-funded programs for energy efficiency and demand response, or from increased distributed generation, materialize as expected within the San Diego area.

Accordingly, the Commission should discount SDG&E and the CAISO analyses as explained in sections I and II. Section III explains why the Commission should not authorize the PPTAs based on alleged system-wide needs for flexible resources. Section IV explains why it would be economically inefficient if the Commission authorized SDG&E to conduct additional procurement as a result of this application even if the Commission finds a potential LCR need in 2020 that exceeds the 450 MW presented for approval through the three PPTAs.

I. The Commission should not approve the PPTAs or authorize additional procurement based on SDG&E's updated estimates of LCR need for 2020.

Approving the PPTAs or granting additional procurement authorization based on SDG&E's sliding assessments of local area needs would be inconsistent both with Commission precedent regarding long term planning and the new approach to LCR planning that is currently being litigated in the 2012 LTPP. SDG&E's supports its LCR assessments by using assumptions that discount preferred resources, use a higher demand forecast, and rely on a spreadsheet rather than a power flow modeling analysis. This is inconsistent with the Commission's directives for long-term planning and raises concerns that SDG&E's procurement to meet local capacity needs would not be compliant with the State's loading order. SDG&E's analysis also departs significantly from the LCR planning approach that is being undertaken in the current, 2012 LTPP, and to adopt SDG&E's approach would result in inconsistent approaches to local needs planning among the utilities. The Commission should therefore not rely on SDG&E's analyses in the original application or on the "updated" LCR analysis SDG&E presented in Mr. Anderson's April, 2012 Supplemental testimony.

A. SDG&E's analyses rely on continuously-sliding assumptions that deviate from the Commission's standardized planning assumptions in the 2010 LTPP.

In the recently-concluded 2010 Long Term Procurement Planning (LTPP) proceeding (R.10-05-006), the Commission adopted Standardized Planning Assumptions based on four scenarios for meeting California's 33% renewable portfolio standards (RPS) by 2020.[6] The results from this Commission-mandated planning scenario predicted a 393 MW surplus of local capacity in 2020 in San Diego (Trajectory Case scenario).[7] Nevertheless, SDG&E requested authorization to procure 450 MW of new generation over the 2012-2020 planning horizon to meet a local capacity requirement (LCR), which SDG&E stated would be satisfied if the Commission approved the instant application.[8] (The other two Investor Owned Utilities (IOUs) did not request any additional procurement authorization.) SDG&E claimed a local need of 180 MW in 2020 to justify its request for 450 MW (a net gain of 415 MW), which it developed by reducing the amounts of peak demand energy savings from uncommitted energy efficiency and demand response compared to the standardized planning assumptions.[9]

Meanwhile, SDG&E filed the instant application seeking approval of the three PPTAs. While SDG&E originally claimed authorization to procure the PPTAs from the 2006 LTPP, that claim is now untenable because the Sunrise Powerlink has been energized.[10] SDG&E has no residual authority from D.07-12-052 that could support authorizing the PPTAs.[11] But SDG&E also submitted a new, third estimate of LCR needs to support the application. That analysis

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[6] Ex. 4 (DRA Testimony), Attachment ("Attch") 2 (SDG&E 2010 LTPP Track I Testimony), p. 2.

[7] Id. at 9.

[8] Id. Attch 1 (DRA's 2020 LTPP Track I Testimony) at 12 (explaining that approving 450 MW PPTAs would result in a net gain of 415 MW).

[9] Id. at 9.

[10] Trx. Vol. 4 612:26 (CAISO witness Sparks). In D.07-12-052 the Commission found SDG&E needed an additional 400 MW of resources through the 2015 planning horizon only if the Sunrise Powerlink project was not developed. D.07-12-052 at 114, Finding of Fact 49, Conclusion of Law 7, Ordering Paragraph 6. The Commission modified D.07-12-052 to acknowledge the uncertainty surrounding the approval and timing of the Sunrise Powerlink project, but required any projects submitted for local capacity needs through 2015 to be supported by updates on the projected online date of the Sunrise Powerlink project. D.08-11-008 at 25-26.

[11] Ex. 4 (DRA Testimony) at 5-6.

claimed a local need of 393 MW in 2020, based on SDG&E's own preferred assumptions in the 2010 LTPP with further reductions to the amount of assumed local renewable and combined heat and power (CHP) resources over the planning horizon. SDG&E removed 107 MW of renewable and CHP resources compared to the 2010 standardized planning assumptions, claiming that those resources would not be located within the load pocket and would have to be brought in over transmission lines.[12]

The Joint Assigned Commissioners' Ruling and the Assigned Commissioner's Amended Scoping Memo and Ruling moved the issue of assessing SDG&E's LCR need from the 2010 LTPP into this proceeding.[13] Pursuant to the amended scope and schedule, the CAISO served testimony on addressing the CAISO's 2011-2012 Transmission Plan. Specifically, the Plan included a new CAISO analysis for 2021, the Once Through Cooling (OTC) study, which assessed local area needs in SDG&E assuming that the Encina power plant is fully retired by 2018 pursuant to the State Water Resources Control Board requirements.[14]

Following the CAISO testimony, SDG&E served supplemental testimony presenting a new, fourth assessment of LCR needs using a load and resources spreadsheet analysis.[15] Revising its prior claim that no RPS additions would be likely to materialize within its service territory,[16] SDG&E now included 16 MW for new RPS in service area to include the Borrego solar plant.[17] SDG&E increased the forecasted 1-in-10 year peak energy demand by 215 MW based on the California Energy Commission's (CEC) preliminary mid-case forecast from the

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[12] Id. (DRA Testimony) at 10 and Attch. 4 (SD&E 2020 Comparison of New Gen Application with LTPP Need). SDG&E also assumed an additional 35 MW of retirements for the existing Wellhead Escondido unit that would be replaced by the 45 MW repowering through the Wellhead PPTA submitted in the Application.

[13] Joint Assigned Commissioners' Ruling, A.11-05-023 and R.10-05-006, Jan. 18, 2012, at 3; Assigned Commissioners' Amended Scoping Memo and Ruling ("Amended Scoping Memo"), Mar. 12, 2012, at 3 (amending scope to consider LCR for 2011-2020 planning horizon including CAISO's 2011-2012 transmission plan).

[14] Ex. 9 (Sparks Testimony, Mar. 9, 2012), Ex. 10 (Sparks Supplemental Testimony, Apr. 6, 2012).

[15] Ex. 11 (Anderson Supplemental Testimony, Apr. 27, 2012), Table 1.

[16] Ex. 7 (Anderson Rebuttal Testimony), RA-16.

[17] Ex. 18 (DRA Supplemental Testimony Attachments), Attch. B; Trx. Vol. 2 253:1-26 (SDG&E witness Anderson).

2011 Integrated Energy Policy Report (IEPR), but lowered its own expectations of savings from incremental energy efficiency measures by 133 MW.[18] SDG&E maintained its assumption that all units at the site of the existing Encina power plant would be fully retired before 2018. As a result of these additional changes, SDG&E increased its estimate of the LCR need in 2020 to 647 MW.[19] Thus, between filing the application in May, 2011 and serving supplemental testimony in April, 2012, SDG&E increased its estimated need by 328 MW ─ or 468 MW compared to its July 1, 2011 LTPP testimony and 861 MW compared to the Commission-mandated Trajectory Scenario under the 2010 LTPP standardized planning assumptions.[20]

B. Pursuant to Commission procurement policies and the amended scoping memo, the Commission should not consider SDG&E's "updated" LCR estimates from April 27, 2012.

The scope of the instant proceeding was amended to consider the results of the CAISO's 2011-2012 transmission studies (including the 2021 OTC study results) "[b]ecause of the centrality of the CAISO processes and data" to the issue of whether SDG&E had need for procurement authorization to meet LCR needs.[21] But the amended scoping memo did not indicate that this proceeding would morph into a separate, full-blown-LTPP for San Diego. Rather, the issue of SDG&E's local needs was deferred to this proceeding in order to allow consideration of the CAISO's 2011-2012 transmission plan results as they pertained to the LCR analysis.[22] The deferment from the 2010 LTPP on a decision of SDG&E's LCR needs was made "[i]n order to ensure that this latest analysis and information from the CAISO [the OTC study results] is integrated into the Commission processes in the most expeditious manner."[23] It did not indicate that the new scope would include comprehensive re-litigation of the standardized planning assumptions.

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[18] Ex. 18, Attch. B.

[19] Id.

[20] Id. (updated need estimate of 468 MW without the PPTAs).

[21] Joint Assigned Commissioners' Ruling, Jan. 18, 2012, at 3.

[22] Amended Scoping Ruling at 3.

[23] Joint Assigned Commissioners' Ruling, Jan. 18, 2012, at 4.

Even if the amended scoping memo could be viewed as ambiguous on the question of whether SDG&E could re-litigate new standardized planning assumptions, authorizing SDG&E's long-term procurement based on SDG&E's own preferred, last-minute updates to the planning assumptions is inconsistent with Commission precedents. The Commission's LTPP proceedings serve as the "umbrella proceeding for the Commission to consider, in an integrated fashion, all of the Commission's electric resource procurement policies and programs, including implementation of directives from other procurement-related proceedings."[24] The Commission has repeatedly confirmed the application of the loading order to energy procurement, stating that "primary principles that are of importance to the Commission are the procurement of the preferred resources set forth in the … "loading order": energy efficiency, demand response, renewables (including self generation), followed at the end of the loading order with efficient fossil-fuel resources."[25] This requirement is also codified at Public Utilities Code (PUC), which mandates that the proposed procurement plan of an electrical corporation shall achieve the following:

> The electrical corporation shall first meet its unmet resource needs through all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible.[26]

Further, the standardized planning assumptions are <u>based upon</u> the loading order.[27] The Commission adjusts the California Energy Demand (CED) forecast of unmanaged load to reflect "adjustments to represent incremental impacts of all 'cost effective, reliable and feasible' demand side resources."[28] Thus, allowing utility to rely on its own preferred set of resources raises concerns regarding utility compliance with the loading order.[29] Given the absence of a

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[24] D.07-12-052 at 9.

[25] <u>Id</u>.at 5.

[26] PUC Sec. 454.5(b)(9)(C).

[27] <u>See</u> D.12-01-033 at 21.

[28] Ex. 18 (DRA Supplemental Attachments), Attch. M at x (Energy Division staff proposal to develop three managed load scenarios) and xi, n.11; Assigned Commissioner's Ruling on Standardized Planning Assumptions ("2012 LTPP ACR on Planning Assumptions"), R.12-03-014, June 27, 2012, Attch. at 10 (planning assumptions will evaluate three managed load scenarios) and 1, n.11.

[29] <u>See</u> D.12-01-033 at 21.

fully updated managed forecast (and in particular the final study of incremental energy efficiency savings scenarios[30]), the Commission should not adopt SDG&E's presentation of half-updated assumptions.

In approving the IOUs bundled procurement plans in the 2010 LTPP, the Commission emphasized that "the utilities cannot just disregard the standardized planning assumptions and procure whatever they want. Doing so would make this whole process ─ and more importantly, Pub. Util. Code Sec. 454.5 … pointless."[31] The Commission rejected Southern California Edison's (SCE) proposal to rely on its own "preferred analysis" that requested variations from the standardized planning assumptions for a planning horizon more than 5 years from the date of the decision.[32] "Beyond [5 years], SCE must use the standardized planning assumptions …. This ensures that SCE's longer-term procurement strategies are consistent with the broader Standardized Planning Assumptions."[33] Although D.12-01-033 addressed the utilities filed bundled procurement plans, the logic similarly applies to longer-term planning, as demonstrated by the Commission's reference to "longer-term" procurement and planning beyond a 5-year horizon.

"The standardized planning assumptions are developed through an exhaustive and open process, involving a wide range of stakeholders."[34] While the debate over planning assumptions in this proceeding may have been exhausting, it was not equivalent to the vetting process that occurs in the long-term planning proceedings with numerous other stakeholders, including the other IOUs. The debate was also hampered by time ─ the Final 2011 IEPR and CED 2012-2022 forecast was only approved only on June 13, 2012, which did not afford the parties a meaningful opportunity to analyze that hundreds-of-pages document prior to the conclusion of the hearings on June 22. Accordingly, the Commission should reject outright ─ or at least give minimal

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[30] 2012 LTPP ACR on Planning Assumptions, Attch. at 12 (parties will be given the opportunity to comment on incremental energy efficiency once the Energy Commission has released the results of its analysis).

[31] D.12-01-033 at 6-7.

[32] Id. at 16.

[33] Id. at 17.

[34] Id.at 5-6.

weight to ─ SDG&E's LCR analyses because they deviate from the last set of approved standardized planning assumptions that were available throughout the course of this proceeding.

C. Authorizing local procurement based on SDG&E's updated LCR estimates would create inconsistencies with the 2012 LTPP Track 1 analysis of LCR needs.

This is the first time that the Commission is considering granting long-term procurement authorization based on LCR studies. The 2006 LTPP decision noted that SDG&E's need determination was constrained by local capacity requirements.[35] But that finding was based on assessment of using the 1-in-2 (average) peak forecast and without making any changes to the Commission's existing 15-17% planning reserve margin (PRM). It was not based power flow modeling or a CAISO LCR analysis.[36] Rather, as the CAISO explained, the CAISO's OTC studies conducted in the 2011-12 Transmission plan is the first time the CAISO has conducted an LCR study for a 10-year planning horizon.[37]

Accordingly, how to utilize LCR studies for long-term planning is a novel question for the Commission. Unfortunately this issue is being resolved simultaneously in two different proceedings at the same time ─ in this proceeding and the 2012 LTPP. It is therefore very important that the Commission adopt approach an approach that is consistent among the utilities. For this proceeding, maintaining a consistent approach means not adopting SDG&E's LCR analyses as the basis for procurement of new local capacity.

First, the Commission should not rely on SDG&E's updated LCR analyses because it uses a <u>different</u> demand forecast than the CAISO used for the OTC/LCR studies that are being considered in Track 1 of the 2012 LTPP. The Track 1 analysis of LCR needs is considering the same 2021 OTC studies that the CAISO presented in this proceeding (but for SCE). The OTC studies used a demand forecast from the 2009 IEPR and have not been updated to reflect the new CED 2012-2022 forecast.[38]

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[35] D.07-12-052, Findings of Fact Nos. 47-49.

[36] <u>Id</u>. at 118 (Table SDG&E-1), Finding of Fact No. 38.

[37] Trx. Vol. 3 534:13-17 (CAISO witness Sparks).

[38] Trx. Vol. 4 639:28-641:8 (DRA witness Spencer).

Further, any the updated standardized planning assumptions will be used to inform resource analyses for Track 2 ─ system and operating flexibility needs—not Track 1.[39] Updated assumptions may also be used for future assessments of local area needs.[40] Accordingly, the Commission should not allow SDG&E to update the demand forecast, or any other planning assumptions, because it would create inconsistencies between the results of the two proceedings and could result in inconsistent long-term procurement directives among the IOUs.

Second, the Commission should not rely on SDG&E's LCR assessments in the record because they are based on a spreadsheet analysis comparing loads and resources ─ not the power flow modeling conducted under the CAISO's transmission studies.[41] While this type of analysis may be useful for assessing impacts on the range of needs due to changing assumptions ─ particularly where parties do not have the capability to conduct their own power flow modeling ─ it is nevertheless a simpler approach than the transmission planning studies conducted by the CAISO based on power flow modeling. The power flow modeling conducted in the OTC study uses a more granular representation of where supply and demand are located.[42] It also uses a detailed representation of the transmission system, whereas the load and resources spreadsheet balancing approach is a simplified accounting of supply, demand, and import capacity.[43] As a result the outcomes can be different, as shown by the fact that SDG&E's April 2012 LCR analyses results in a higher LCR than the CAISO's OTC study. This is partly because SDG&E uses a higher load forecast, but also because SDG&E assumed a different contingency, assuming loss of the largest generator and a transmission line (the G-1/N-1 contingency) rather than the loss of two transmission lines (the N-1-1 contingency).[44]

The 2010 LTPP included the assessment of needs in locally constrained areas as an issue within the scope of the proceeding, but noted that "we expect that the IOUs will not use simple

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[39] 2012 LTPP Scoping Memo, at 9.

[40] 2012 LTPP ACR on Planning Assumptions, Attachment at 6.

[41] See Ex. 17 at 3-6 (Fagan Supplemental Testimony).

[42] Id. at 6.

[43] Id. at 5-6.

[44] Ex. 12 (Strack Supplemental Testimony) at JS-8; Ex. 17 (Fagan Supplemental Testimony) at 30.

L&R [Load and Resources] spreadsheets, instead they shall use modeling techniques such as power flow analyses to demonstrates the results of their methodology."[45] All of SDG&E's LCR analyses in the record of this proceeding rely on L&R spreadsheet analyses. Only the CAISO's OTC study relies on power flow modeling ─ and the CAISO claims that a different set of contingencies (N-1-1) should determine the need, not the contingency assumed in SDG&E's spreadsheet analysis (G-1/N-1). Given the complexity of the power flow modeling and its sensitivity to input assumptions, the Commission should adopt as consistent an approach in developing LCR needs as is possible between this proceeding and the 2012 LTPP Track 1. Accordingly, the Commission should not adopt an LCR need based on SDG&E's higher LCR assessment. It should focus narrowly on determining how to use the CAISO's OTC Study for 2021 (which should be adjusted to reflect the State's loading order).

D. SDG&E's reluctance to rely on preferred resources to meet local needs is inconsistent with the loading order and is overly-conservative.

In supporting its reductions to energy efficiency, demand response, and renewable resources within its service territory, SDG&E argues that the Commission should use "realistic yet conservative" assumptions for assessing LCR needs.[46] Thus, SDG&E states that the Commission should only count towards local resources only the loading order resources that SDG&E thinks are "reasonably certain" to appear in future years for meeting the local need.[47] And by "reasonably certain" SDG&E means resources that have a "very high probability of being there."[48] SDG&E also appears to claim that it can meet the loading order using system, rather than local resources, and thus distinguishes its procurement planning to meet local needs

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[45] Assigned Commissioner and Administrative Law Judge's Joint Scoping Memo and Ruling, R.10-05-005, Dec. 3, 2010 at 21.

[46] Ex. 24 at RA-5 - RA-7 (Question and Answer No. 5) (emphasis added) (Anderson Supplemental Rebuttal Testimony).

[47] Id.; Trx. Vol. 1 124:17-125:21 (SDG&E witness Anderson).

[48] Trx. Vol. 1 70:2—71:8; Trx. Vol. 1 95:15-18 (SDG&E prefers to "only rely on those assumptions that we each believe have a high probability of coming to fruition") (SDG&E witness Anderson).

from SDG&E's actions to implement the loading order.[49] These arguments fail for at three reasons.

First, neither the Commission nor PUC Sec. 454.5 authorizes an exception to the loading order for meeting local area needs. By contrast, the Commission has emphasized that "[a]ll utility procurement must be consistent with the Commission's established loading order."[50] Decision 12-01-003 clarified the Commission's position that "we expressly endorse the general concept that the utility obligation to follow the loading order is ongoing. The loading order applies to <u>all utility procurement</u>, even if pre-set targets for certain preferred resources have been achieved."[51] The Commission has not previously created exceptions for long-term planning based on local area needs, and it should not create one in this proceeding.

Second, most of SDG&E's demand contributes to local ─ not system ─ needs, because SDG&E is a load pocket.[52] The local demand captures about 95% of the total system demand for SDG&E.[53] Thus, it is unclear how SDG&E could fulfill the loading order using system resources (resources that can come in over the transmission lines[54]) rather than local resources. Demand side reductions do not come in over transmission lines, they reduce the load in the first instance. Further, many distributed generation resources are behind-the-meter or other demand-side resources that would occur in SDG&E's service territory and would be reflected through reduce load forecast.[55] Energy efficiency and demand response "are considered the highest priority and should be employed first by a utility in making procurement decisions since they are

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[49] Ex. 24 at RA-5 ("The intervenors have made no showing that the preferred resources do not fit within this entire resource need", meaning the "total resources need[ed] to service the load in the SDG&E load pocket.") (Anderson Supplemental Rebuttal Testimony).

[50] D.12-01-033 at 17.

[51] <u>Id</u>. at 20 (emphasis added).

[52] Trx. Vol. 1 120:21-25 (SDG&E's service area is a load pocket) (SDG&E witness Anderson).

[53] Trx. Vol. 118:20-119:21 (SDG&E witness Anderson); Ex. 24, RA-5 (total system need including 15% reserve margin is 6,121 MW) (Anderson Supplemental Rebuttal Testimony); Ex. 11 table 1 (local need based on 1-in-10 forecast is 5,824) (Anderson Supplemental Testimony). 5,824 divided by 6,121 equals 95%. DRA does not endorse using the updated, Preliminary CED demand forecast, but presents this analysis for illustration.

[54] Trx. Vol. 1 123:25-26 (SDG&E Witness Anderson).

[55] Trx. Vol. 2 267:2-18, 258:6-260:25 (SDG&E Witness Anderson).

demand-side resources."[56] Thus, allowing SDG&E to use lower forecasted energy efficiency or demand response assumptions for local area planning (versus system) would violate the loading order.

Third, adopting SDG&E's approach of planning for a very low-probability event using what it decides are "high-probability" resources is unsupported. It would create an unbalanced approach and would likely lead to over-procurement. As Ms. Firooz explained, the probability of occurrence of the 1-in-10 peak event with a G-1/N-1 or N/1-1 contingency is under 0.0001% in a given year, and would expect to occur for well under 10 minutes over 10 years.[57]

SDG&E's claim that it selected "high probability" resources is unsubstantiated. SDG&E did not present any estimates of the probability that any range of demand side reductions would materialize—it simply reduced its estimates for energy efficiency and demand response based on its own new forecasts. It assumed a 0% probability that any future additional renewable or distributed resources will appear within SDG&E's service territory except a single contract that SDG&E has deemed is "extremely high probability" because it has gone through "all Commission approvals."[58] But all of these estimates ignore that the standardized planning assumptions reflect the Commission's assessments of what are "cost-effective, reliable and feasible" demand-side resources.[59]

Ratepayers will pay a $1.88 billion just for the capacity costs of the PPTAs.[60] When assessing the tradeoffs of whether to authorize that procurement or not, the Commission should not further discount the potential impacts of ratepayer-funded programs for energy efficiency, demand response, and incentives for distributed resources in light of the extreme and far-off circumstances addressed in the transmission planning study.

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[56] D.07-12-052 at 12.

[57] Ex. 20 at 5 (Firooz Direct Testimony); Trx. Vol. 3 at 465:14 - 467:10 (CEJA witness Firooz).

[58] Trx. Vol. 2 253:1-25 (SDG&E Witness Anderson).

[59] See supra section I(B).

[60] Ex. 35-C (unshaded (public) value in top right of page). The net present costs are also substantial as shown in the confidential portions of the attachment.

E. The Commission should not rely on the recent California Energy Demand forecast, but if it does, it should also consider higher levels of distributed generation.

In supplemental testimony and during the hearings, SDG&E presented a new, updated LCR analysis using a new California Energy Demand 2012-2022 forecast (the preliminary and final forecasts). The Commission should not authorize procurement today based on SDG&E's last-minute updating using the mid-range level of that forecast. However, if it does update the demand forecast, it should also incorporate higher amounts of distributed generation into SDG&E's LCR estimates to account for the Governor's commitment to increasing distributed generation throughout the state.

1. The mid-case CED 2012-2011 forecast will over-forecast demand if the economy remains in a protracted slump.

When considering the implications of the new forecast, the Commission should consider both the low- and mid-case scenarios, and the decision of which demand estimate is likely to occur should be consistent with any decision from Track 2 in the 2012 LTPP. The Commission is evaluating the full range of projected demand to develop managed load scenarios in Track 2 of the 2012 LTPP based on the low-, mid-, and high- demand CED forecasts.[61] The mid-demand forecast uses "Moody's base case" for the economic growth, but the low case uses "Moody's protracted slump."[62] Whether the economy is likely to remain in a "protracted slump" will likely become clearer as the parties to the 2012 LTPP proceeding continue to develop proposed scenarios that will form the basis of updated studies in 2013.[63] The Commission should not get ahead of informed determinations on this same issue to be made in the 2012 LTPP.

As history has shown, actual demand can certainly turn out to be lower than forecasted in the CED's medium-case scenario. The California Energy Demand's 2009-vintage forecast overestimated the peak demand in 2011 for San Diego's planning area. The actual 2011 peak was 223 MW ─ 5% lower ─ than the 2009 forecast (forecast peak of 4,578 compared to actual of

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[61] Ex. 18 Attch. M at x, ACR on Standardized Planning Assumptions, R.12-03-014, June 25, 2012 at 10 (DRA Supplemental Attachments).

[62] Id. at 11, Ex. 18 Attch. M at xi.

[63] 2012 LTPP Scoping Memo at 10.

4,355).[64] Similarly the "low" final estimate of peak assuming protracted economic slump is 5.5% lower than the mid-peak estimate for 2020.[65] Reducing the 1-in-10 year peak for 2020 is by 5% from the mid-forecast reduces the 1-in-10 peak demand by 320 MW, which is even less than the original demand estimate SDG&E presented in this proceeding (a 1-in-10 peak forecast of 5,609).[66]

2. California's commitments to increasing distributed generation will likely yield additional local benefits by 2020.

While asking for an updated demand forecast, SDG&E's analyses disregards California's commitments to developing additional generation to meet a 12,000 MW goal of localized energy by 2020.[67] SDG&E's estimates include 17 MW of additional demand-side Combined Heat and Power (CHP) resources that are likely to be distributed generation.[68] It included an additional 16 MW for a local solar project.[69] The updated CED 2012-2022 demand forecast reflects a reduction from peak demand of 288 MW in 2020 that includes the effects of the Self Generation Incentive Program and the California Solar Initiative.[70] This total ─ 321 MW ─ is far less than the 2020 goals the California Energy Commission (CEC) recently recommended for the San Diego region to meet the Governor Jerry Brown's 12,000 MW renewable distributed generation target.

Under the CED goals, an estimated 1,180 MW of distributed generation would be required by 2020 in the San Diego region. SDG&E's witness explained that one can estimate the peak reduction from demand by multiplying the installed capacity by 0.6 (reflecting a 60%

[64] Ex. 32 (third section of table, Peak (MW) showing historical values in shading).

[65] Id. (comparing low-peak (5,066) to mid-peak (5,359) shows a 5.46% reduction for the low).

[66] See Ex. 24 at RA-9 (reducing final CED 1-in-10 peak of 5,863 MW by 5% yields 5,569 MW) (Anderson Supplemental Rebuttal Testimony).

[67] Ex. 16 at 9-11, 13 (Spencer Supplemental Testimony).

[68] Trx. Vol. 2 258:24-26 (SDG&E witness Anderson); Ex. 11 at RA-5 (Anderson Supplemental Testimony);

[69] Id. (RPS in service area line).

[70] Ex. 33 (total self-generation, mid demand); Trx. Vol. 2 261:21-262:17 (SDG&E witness Anderson).

production value).[71] Multiplying the 1,180 MW goal for total distributed generation yields an estimated peak load reduction of 708 MW for San Diego in 2020.

Thus, achieving the Governor's goals would more than double the total amount of distributed generation compared to the assumptions included in SDG&E's LCR estimates presented in Exhibit 11, Table 1. SDG&E's witness testified that SDG&E would be committed to meeting whatever goal for additional distributed generation is adopted to meet the Governor's plan.[72] Further, installation of additional distributed generation would not have to come from SDG&E's Renewable Portfolio Standard portfolio of contracts[73] or be required to obtain full deliverability to count towards resource adequacy.[74] Behind-the-meter distributed generation (such as rooftop PV and net metering) would be reduced from the demand forecast and thus would reduce the LCR requirements.[75]

F. SDG&E's need analysis ignores the possibility that the CAISO will still require generation at Encina site even <u>with</u> the PPTAs, or additional transmission upgrades if Encina retires to make the PPTAs fully deliverable.

Each of the PPTAs will impose substantial costs on ratepayers, starting several years before the expected retirement of the Encina plant.[76] Yet they can only be justified based on their expected contributions to promoting grid reliability if the Encina plant is fully retired by 2018. SDG&E has assigned a 0% probability that NRG (the owner of Encina and developer of the Carlsbad Energy Center Project (CECP)) will achieve alternative compliance that would allow Encina units 4 and 5 to remain in operation or continue to pursue development of replacement (repowered) generation at Encina. Another reasonable assumption is to consider the likelihood of continued generation at Encina, given (1) CAISO's position that generation will be

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[71] 266:27-267:1 (SDG&E witness Anderson).

[72] Trx. Vol. 2 263:20-24 (SDG&E witness Anderson).

[73] Trx. Vol. 2 267:2-17 (SDG&E witness Anderson).

[74] <u>See</u> Ex. 24 at RA-17 (Anderson Supplemental Rebuttal Testimony) (noting that the feed-in-tariff bill does not require that the capacity be deliverable).

[75] Trx. 259:8-560:4 (SDG&E witness Anderson) (describing behind-the-meter distributed generation as including solar PV and net metering).

[76] Ex. 4-C at 17-18 (DRA Testimony), Ex. 35-C.

required at the Encina location even if the PPTAs are approve, and (2) the record evidence showing that if Encina is retired, it could reduce the deliverability of the PPTAs and thus reduce their ability to count fully toward SDG&E's local resource adequacy needs.

First, SDG&E fails to acknowledge that the CAISO is reluctant to allow Encina to retire without replacement generation at the same site. Both the CAISO and CEC staff have supported the proposed 558 MW Carlsbad Energy Center Project (CECP) the CEC proceeding addressing NRG application for CECP.[77] The CAISO has repeatedly maintained that an Encina sub-area requires local capacity 150 MW at the Encina site, even with the PPTAs.[78] While SDG&E claimed at hearings that it would implement a reconductoring project to eliminate the sub-area, the CAISO has not yet approved that project.[79] Further, even if SDG&E moves forward on the reconductoring project without CAISO approval, it may not be completed until 2015.[80] If the PPTAs come online before the reconductoring project is completed,[81] ratepayers might still need to fund resource adequacy to meet Encina sub-area requirements. Thus, if the Commission approves these PPTAs, it should require as a condition of approval that they not become operational until after the CAISO eliminates requirements for an Encina sub-area.

Second, even if the Encina sub-area is eliminated, the CAISO maintains that additional generation still would be required with the PPTAs, which could be satisfied by ongoing operations of Encina or the CECP.[82] So while it may be true that the PPTAs (or some portion of them) are needed to allow Encina to retire, it may also be true that the CAISO will require ongoing operations at Encina even if all three PPTAs are approved. For example, if the CAISO refuses to consider any demand side management reductions to reduce LCR needs in the future (including energy efficiency and demand response) it could require continued operations of

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[77] Ex. 15 at 10-12 (Ghazzagh Supplemental Testimony).

[78] Ex. 9 at 4 (Sparks Original Testimony); Ex. 10 at 5, 10 (describing sensitivity study) (Sparks Supplemental Testimony); Ex.18, Attch. E at transcript page 57:14-19.

[79] Ex. 37; Ex. 38 (Response to DRA-CAISO-20(c)) (reference Sycamore Canyon-Chicarita line).

[80] Trx. Vol. 3 425:7-17 (SDG&E witness Strack).

[81] Trx. Vol. 2 327:22 (Pio Pico online date is May, 2014), 331:5-7 (Quail Brush online date is June 2014) (SDG&E witness Eekhout).

[82] Trx. Vol. 3 585:28-586:8 (CAISO witness Sparks); Ex. 38 (Response DRA-CAISO-26(a)).

Encina under its capacity procurement mechanism (CPM). That could result in SDG&E ratepayers having to bear both the costs of the PPTAs and the administrative CPM costs or the costs of replacement generation (such as the CECP).

The California Energy Commission also recently issued its final approval of CECP, relying on CAISO statements that Encina units 4 and 5 may be required to stay online indefinitely if CECP is not constructed.[83] NRG is also continuing to pursue a mitigation plan that would allow units 4 and 5 to remain in operations beyond the 2017 OTC compliance date.[84] While SDG&E disputes whether NRG will achieve compliance through its OTC implementation plan, the indisputable facts show that NRG is continuing to pursue both the CECP and the alternative compliance to meet the State Water Resources Control Board's OTC rules. "Long-term planning assumptions should reflect real-world possibilities, including the stated positions or intentions of market participants."[85] Thus, the Commission should not entirely discount the possibility that NRG will continue operations for Encina units 4 and 5 or repower the existing generation at Encina.

Finally, the CAISO also has maintained that without additional network upgrades and if there is no generation Encina, the Pio Pico and Quail Brush projects may not be fully deliverable.[86] Thus, Net Qualifying Capacity (NQC) of these projects may be reduced without further mitigation through transmission upgrades or use of some special protection systems.[87] The CAISO has not approved these upgrades.[88] If the CAISO fails to approve them until a certain date exists for the retirement of Encina, a position it has taken with respect to other upgrades,[89] it could create a situation where the projects are not fully deliverable for years when their NQCs are reduced. Ratepayers would thus lose the benefits of the projects equivalent to

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[83] Ex. 36; Ex. 15 at 12 (Ghazzagh Supplemental Testimony).

[84] Ex. 14 at 7-10 (Theaker Testimony); Trx. Vol. 2 at 366:22-367:1 (SDG&E witness Strack).

[85] Ex. 18 Attch. M at v; 2012 LTPP ACR on Planning Assumptions at 8 (setting out guiding principles for the 2012 LTPP).

[86] Ex. 38 (Response DRA-CAISO-20(b), Response DRA-CAISO-21).

[87] Trx. Vol. 3 545:1-16, 589:13-24 (CAISO witness Sparks), Trx. Vol. 3 419:11-421:17 (SDG&E witness Strack).

[88] Ex. 37 at 207, Ex. 38 (Response to DRA-CAISO-21).

[89] Ex. 38 (Response to DRA-CAISO-20(c)).

any reduction in their NQC. If the Commission approves the PPTAs, it should require SDG&E's shareholders, not ratepayers, to bear the costs of any replacement resource adequacy that could be needed if this set of foreseeable circumstances comes to pass.

DRA does not necessarily support the CECP over the proposed contracts. But deferring procurement that may be unnecessary (and for projects that may not able to fully deliver energy benefits in the first years of the contracts) would avoid unnecessary rate increases, particularly given the uncertainty that the PPTAs are even needed to meet local reliability needs. For example, SDG&E calculates that it would cost approximately $10.6 million (nominally) per year to ensure that 150 MW of generation capacity were kept online at the Encina site using the CAISO's CPM.[90] By extension, if the CAISO exercised the CPM to retain Encina units 4 and 5 it would cost $45.4 million per year.[91] This is indisputably much less than the yearly nominal capacity costs under the Quail Brush and Pio Pico projects.[92]

II. The OTC study results should not be adopted for long-term procurement authorization without accounting for energy efficiency, demand response, and other potential transmission mitigation alternatives.

This is the <u>first</u> instance where the CAISO has conducted a local capacity transmission study set 10-years in the future, and thus the first time the Commission has considered authorizing long-term procurement based on the study results.[93] Historically, the Commission has used CAISO LCR study results to examine short-term reliability issues.[94] The LCR results are generally adopted by the Commission through the Resource Adequacy program for a 1-year planning horizon, to ensure adequate resources will be available.[95]

Any forecast of the future is uncertain. But the CAISO's testimony recommends that the Commission authorize SDG&E to procure new gas-fired generation facilities based on a

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[90] Ex. 12 at JS-12 (Strack Supplemental Testimony).

[91] Encina units 4 and 5 total 640 MW Ex. 4 at 11 (DRA Testimony). 640 MW times $70.88/kW-year times 1000 kW/MW equals $45,363,2000/yr or $45.4 million/year.

[92] Ex. 4-C at 17 (sum of top two portions of bar graph for Pio Pico and Quail Brush) (DRA Testimony).

[93] Trx. Vol. 3 533:22-534:17 (CAISO witness Sparks).

[94] Ex. 16 at 7-8 (Spencer Supplemental Testimony).

[95] <u>Id</u>.

combination of worst-case assumptions that could occur in 2021. This is without regard to the range or uncertainties in the forecasts or the low probability that such events might occur, and without accounting for any demand reduction measures such as energy efficiency and demand response.

Because the application of the CAISO OTC transmission planning study to long-term resource presents issue of first impression for the State, the Commission should take extra caution to ensure that its decision is consistent with its statutory mandate to ensure just and reasonable rates,[96] as well as the State's loading order.[97] Accordingly, the Commission should not set a procurement target to meet 100% of the CAISO's highest OTC need result. That worst-case outcome that fails to recognize future developments on the transmission system and that would likely result in over-procurement or crowd-out preferred resources. Accordingly, it should adjust the CAISO results downward to reflect:

- the planning horizon of this proceeding (2020, not 2021),
- the State's requirements to first meet unmet electricity needs through demand-side reductions such as energy efficiency and demand response,
- the range of uncertainties inherent in the LCR study results due to their sensitivity to the location of load and resources,
- the potential that future transmission upgrades or other cost-effective transmission solutions could reduce SDG&E's LCR needs, and
- other reasonable alternatives that could be available to mitigate the extreme conditions studied such as an SPS.

If the Commission made just some adjustments to the OTC study results, it reveals there would be a surplus in local resources in 2020 (and hence there would be no need to approve the PPTAs). This is true even if the Commission relied on SDG&E's updated (lower) assumptions for energy efficiency and demand response and assumes no additional distributed generation resources will be installed in the San Diego are beyond the conservative amount embedded in the CED forecast, as shown in the table below:

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[96] PUC Sec. 451 (All charges demanded or received by any public utility ... shall be just and reasonable. Every unjust or unreasonable charge demanded or received for such product or commodity or service is unlawful.")

[97] See PUC Sec. 454.5(b)(9)(C), D.12-01-033 at 17, 21.

Table - SDG&E's Local Area Need (+ surplus / - deficiency)
using CAISO OTC Study Results, SDG&E's "Updated" EE and DR assumptions,
and applying SPS to reduce need.

	Adjustment:	Trajectory	Environ-mental	Base	Time
CAISO result from OTC scenario	None	-730	-300	-630	-540
2020 demand adjustment	add 76 MW	-654	-224	-554	-464
SDG&E's Updaed Energy Efficiency (low)	add 151 MW	-503	-73	-403	-313
SDG&E's Updated Demand Response	add 219 MW	-284	146	-184	-94
Apply SPS to mitigate double contingency	add 378 MW	**94**	**524**	**194**	**284**

The Commission should adjust the CAISO load forecast, as explained in the remainder of this section.

A. The CAISO OTC results should be reduced to reflect 2020 values.

After correcting for errors in prior assumptions regarding transmission planning requirements, the CAISO's 2021 OTC analysis presented local generation needs in 2021 ranging from 300 MW (environmental case) to 730 MW (trajectory case) based on the four renewable integration scenarios developed in the 2010 LTPP.[98] The CAISO study is for 2021, however, and the thus the demand forecast was 76 MW higher than 2020 to reflect load growth from 2020-2021.[99] The planning horizon in this proceeding is 2011-2020.[100] Accordingly, as a first adjustment, the CAISO results should be adjusted to 2020 values. This yield a range of needs from 224 MW (environmental scenario) to 654 MW (trajectory case).

B. Adopting the OTC study results without making adjustments for demand side measures would violate the loading order.

The CAISO's OTC study assumes that no incremental (uncommitted) energy efficiency savings will occur in the future and that demand response programs would not contribute to meeting any portion of local capacity needs.[101]

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[98] See Ex. 9 at 7-8 (Sparks Original Testimony).

[99] Ex. 18, Attch. H (CAISO Response to DRA-CAISO-04). The CAISO forecast is also 64 MW higher in 2020 than the demand forecast SDG&E presented in the 2010 LTPP and originally in this Application. See Ex. 4, Attch. 3 ("Product 2 Need Worksheet (in LTPP format) (DRA Testimony).

[100] Amended Scoping Memo at 3 (issue 1A).

[101] Ex. 18, Attch. A, H (CAISO Response to DRA-CAISO-04); Ex. 27 at 2 (Sparks Rebuttal Testimony).

1. The CAISO has not stated any legal justification to exempt SDG&E from the loading order requirements for local planning.

Authorizing procurement based on the unadjusted OTC results would amount to unlawfully exempting SDG&E from its statutory requirement to meet unmet energy needs first through energy efficiency and demand response, then renewable resources, and last by building new conventional generation.[102] But, "[a]ll utility procurement must be consistent with the Commission's established loading order."[103] Procurement to meet local needs is not statutorily exempted.[104] The CAISO has not provided any explanation for why such an exemption is legally required or justifiable.

Instead, the CAISO defends its refusal to include energy efficiency and demand response only by saying that they are the CAISO's preferred assumptions. Regarding energy efficiency, the CAISO only says "the [CA]ISO does not believe that it is prudent to rely on uncommitted resources for assessing future local system needs."[105] Regarding demand response, the CAISO only says "the [CA]ISO does not agree that Demand Response can be relied upon to address local capacity needs, unless the DR can provide equivalent characteristics and response to that of a dispatchable generator."[106] Neither of these statements about the CAISO's preferences for long-term planning assumptions provides a legal justification for ignoring the loading order for long-term resource planning in local areas.

Rather, the CAISO's explanations indicate that it is simply replacing the Commission-mandated standardized planning assumptions with its own. But the CAISO is not the resource

[102] PUC Sec. 454.5(b)(9)(C); see also D.12-04-045 at 206, Finding of Fact No. 4 ("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.")

[103] D.12-01-033 at 17.

[104] See supra Sec. I(D).

[105] Ex. 27 at 2. (Sparks Rebuttal Testimony).

[106] Id. at 5. In addition to being unsupported by any analysis proving that none of SDG&E's demand response programs could provide such characteristics, it is also inconsistent with the CAISO's admission that demand response can be utilized to count towards reducing local capacity needs and its own projection that 108 MW of demand response is available to reduce the LCR. Ex. 17 at 25-26 (Fagan Supplemental Testimony); Ex. 18 Attchs. A, H (DRA Supplemental Attachments).

planner.[107] That is the Commission's role and jurisdiction. That is particularly true here, because there is not currently an LCR deficiency. A deficiency may arise due to the potential retirement of Encina to comply with the State's OTC retirement policies. But the Encina retirement does not create a short-term reliability emergency.

Further, the CAISO itself has a statutory duty to conduct its operations "consistent with applicable state and federal laws and consistent with the interests of the people of the state."[108] This includes managing the transmission grid and related energy markets "in a manner that is consistent with ... [a]pplicable state law intended to protect the public's health and the environment."[109] The loading order is state law and promotes California's interest in meeting energy needs while minimizing environmental risks and impacts. Thus, ignoring preferred resources in its long-term transmission planning is inconsistent with the CAISO's obligations under PUC Sec. 345.5. The CAISO has not stated any legal justification to exempt SDG&E from the loading order requirements for local planning.

2. The CAISO has not identified transmission standards that require procuring generation for a 10-year need or assuming no future demand management.

The CAISO has not claimed that the transmission planning standards dictate procurement of conventional generation on 10-year horizon or disregarding the State's mandated planning assumptions for preferred resources. They do not.

First, the transmission planning standards only require the CAISO to conduct transmission planning for a longer than five-year horizon "as needed to address identified marginal conditions that may have longer lead-time solutions."[110] As Mr. Fagan explained, the purpose of the ten-year horizon is to guide consideration of resource procurement needs, "but it is not a long-range resource plan for procurement of generation."[111] The CAISO did not dispute Mr. Fagan's contention. It did not (and could not) claim that the transmission planning standards

[107] Trx. Vol. 3 554:19-26 (CAISO witness Sparks).

[108] PUC Sec. 345.5(a).

[109] Id. (emphasis added).

[110] Ex. 17 at 15-16 (Fagan Supplemental Testimony); Ex. 18 Attch. CC (Standard TPL-001-1 at 1-2).

[111] Ex. 17 at 16.

require the CAISO to carry any specific amount of operating reserves for ten-years out.[112] Conventional generation resources may not be the only, or most cost-effective, solution to timely address any "marginal conditions" that might be identified as needed under a longer-term transmission plan.

Second, the transmission planning standards require the CAISO to develop models and maintain plans subject to auditing by the North American Electric Reliability Corporation (NERC).[113] But the CAISO has not claimed that the planning standards require using zero contributions from demand-side resources such as energy efficiency and demand response. Rather, the CAISO witness did not know what method the NERC specifies for forecasting load.[114] And when asked directly if the transmission planning standard requiring disregarding the loading order requirements, the CAISO's witness stated only that "[t]he [CA]ISO's analysis is based on our judgment of what is dependable resources in the planning horizon."[115] The CAISO could not, however, tie this judgment to NERC requirements.

3. If the Commission assigns zero benefits to demand management programs in meeting local area needs, then it should not require ratepayers to fund any future programs.

Adopting the OTC study results without reductions to account for demand management programs would essentially assign a 0% probability of success that demand response and further energy efficiency programs will yield future energy savings. It would reduce the benefits of the programs to zero. Yet, the Commission has approved hundreds of millions of dollars for ratepayer-funded energy efficiency and demand response programs in SDG&E's territory.[116]

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[112] Trx. Vol. 3 554:9-7, 562:12-20 (CPUC, not WECC, specifies the planning reserve margin for load-serving entities), 563:13-564:12 (long-term reserve margin requirements defer to the CPUC systemwide planning reserve margin), 564:13-565:6 ("Balancing authorities are responsible for operating the system primarily from day to day, hour to hour."); Trx. Vol. 4 597:27-598:6 (transmission planning standards specifying 2.5% margin do not require the CAISO to carry any operating reserves for ten years out) (CAISO witness Sparks).

[113] Trx. Vol. 3 583:5-6 (CAISO witness Sparks).

[114] Trx. Vol. 3 554:9-26 ("I don't believe NERC specifies the method of forecasting load.") (CAISO witness Sparks).

[115] Trx. Vol. 4:16-599:6 (CAISO witness Sparks).

[116] D.09-09-047, Ordering Paragraph 3(d) at 365-366 (approving $278 million energy efficiency budget for SDG&E for just the 2010-2012 program years); D.12-04-045 at 194-195 (total $117 million

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These program budgets are approved based on assumptions that they reduce peak energy demand (and hence the need for additional peaking resources), and thus are valuable to ratepayers because they reduce the need for conventional power plants. If ratepayer-funded energy efficiency and demand response programs that burden ratepayers with additional costs, but then are not relied upon at all to achieve offsetting cost reductions from avoided new conventional resources, then why should ratepayers continue to fund them?

Given the potential precedential effects of this decision, the Commission should not cede lightly its jurisdiction over resource planning and planning assumptions to the CAISO's preferences. It should follow the statutory mandates. And the Commission should discount the CAISO's unsubstantiated claim that under-procurement causes risks but not over-procurement.[117] The CAISO submitted no cost-benefit analyses to support such claims[118] and they do not rebut concerns that over-procurement can lead to underutilized or stranded assets.[119]

Accordingly, the Commission should reduce the OTC local need results to reflect expected amounts for uncommitted energy efficiency and demand response in 2020. Although it reverts to a "spreadsheet type"of analysis, in the absence of the CAISO's agreement to re-run the OTC study using Commission-mandated planning assumptions, the Commission can remove the amounts of preferred resources from the San Diego local need.[120]

(continued from previous page)

authorized for demand response program budgets for 2009-2011 and 2012-2014 program years).

[117] Ex. 27 at 3 (Sparks Rebuttal Testimony).

[118] Trx. Vol. 3 591:18-292:24 (CAISO does not have "great visibility on the costs of generation nor the demand response").

[119] Ex. 16 at 2-3 (Spencer Supplemental Testimony) at 2-3.

[120] Ex. 17 at 25 (Fagan Supplemental Testimony) (CAISO explained that demand response amount can count against local deficiency), 26 (LCR need would be reduced by roughly the level of energy efficiency reductions assumed). See also Ex. 18, Attch. M (Energy Division Staff Report stating "load reductions in the range of 500 MW in SDG&E service area have impacts on [local capacity area] requirements in San Diego.")

C. Procurement authority based on the CAISO OTC results should account for the range of uncertainty and sensitivity of the power flow modeling to the input assumptions.

The actual LCR requirements in 2021 are uncertain and sensitive to the input assumptions, but the OTC study ignores dynamic patterns that govern the transmission system and define local reliability needs. The CAISO's power flow modeling presents a single snapshot of the future ─ one set of outcomes based on a single set of assumptions for the demand, generation resources, and transmission facilities in 2021.[121] These power flow modeling results are indisputably very sensitive to assumptions about the amount and location of demand and supply resources, and assumptions about future possible transmission upgrades. They have, and could again, be lower in future studies.[122] The Commission should account for these uncertainties and the fact that the actual locations of load and generation and transmission facilities will change over time. It should not authorize procurement based on the single worst result from the studies.

First, the OTC study results are highly sensitive to the location of the demand and resources in and around the San Diego area.[123] This includes assumptions about where projects being developed to meet the 33% RPS will actually be placed.[124] Although the CAISO did not perform other sensitivity analyses for ranges of input assumptions, the four cases studied do reveal how the LCR results vary just assuming different portfolios of renewable resources that were through the 2010 LTPP.[125] The results show a wide range in the resulting resource need depending on the assumed location of renewable resources in and around the San Diego area,

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[121] Id.at 5.

[122] Trx. Vol. 3 572:15-574:11 (CAISO witness Sparks).

[123] Trx. Vol. 3 565:18-566:1, 544:5-13 ("Definitely, the point of injection of the power can influence the flows on the constraints.") (CAISO witness Sparks); Trx. Vol. 3 447:17-448:7 ("And what was clear in his results are, not surprisingly, quite contingent on the assumptions that were made for the purposes of that [CAISO base renewable portfolio] case.") (SDG&E witness Strack).

[124] Trx. Vol. 3 568:28-569:10 (CAISO witness Sparks).

[125] Trx. Vol. 3 569:11-570:15 (CAISO witness Sparks).

with a 430 MW difference between the low (environmental) and high (trajectory) end of the results.[126]

In fact, under environmental scenario (which assumes higher amounts of distributed generation) SDG&E would need only 224 MW of local resources in 2020 without accounting for any demand-side reduction measures.[127] That need could be met through the Quail Brush and Wellhead PPTAs without approving the Pio Pico project, and would disappear altogether if the Commission applied SDG&E's own updated assumptions for incremental energy efficiency and demand response (370 MW in 2020).[128]

Second, the CAISO's power flow modeling also assumes one state of the transmission system in 2021, based on projects approved in the 2011-2012 transmission planning cycle.[129] It does not account for any additional upgrades to the system that could be implemented in future rounds of transmission studies. But when discussing the likelihood for additional transmission upgrades to be implemented in San Diego by 2020, the CAISO itself acknowledged that "it would be reasonable to predict that there will be more in the future."[130] Such transmission upgrades could lower San Diego's local capacity needs.[131]

In conducting the OTC study the CAISO also rejected other alternative transmission projects that could mitigate transmission constraints into the San Diego area and reduce the need for additional peaking power plants within the load pocket. The CAISO's original testimony stated that the scope of upgrades needed to meet a 650 MW to 950 MW need was "essentially a new 500 kv line connecting the SDG&E system to the SCE system."[132] But after the CAISO revised the study results, three of the need estimates were under 650 MW, a range that could possibly be met by a 230 kV line.[133]

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[126] Ex. 10 at 3.

[127] Environmental case adjusted for 2020 demand.

[128] Ex. 11 at RA-5, Table 1 (Anderson Supplemental Testimony).

[129] Trx. Vol. 3 567:28-568:27 (CAISO witness Sparks).

[130] Trx. Vol. 3 567:19-27 (CAISO witness Sparks).

[131] Trx. Vol. 3 566:7-25, 567:19-568:27 (CAISO witness Sparks).

[132] Ex. 9 at 9 (Sparks Original Testimony).

[133] Ex. 10 at 3 (Sparks Supplemental Testimony); Trx. Vol. 4 617:11-17 (CAISO witness Sparks).

The LCR results can also be affected by changes in the transmission planning standards[134] or interpretations of them. (This was demonstrated by the fact that the CAISO had to re-run the study and submit revised results.[135]

Given the potential that each or all of these factors will change over time, and will be informed by future transmission studies, the Commission should not endorse the upper, highest range of need for setting a procurement authorization.

D. The CAISO OTC analysis should be adjusted to reflect possible SPS measures such as controlled load drop.

The CAISO's final OTC analysis results also do not include reductions from the LCR need based on the potential to use other transmission operation protocols (such as controlled load drop). An SPS could maintain reliability of the transmission system if the worst-case outcomes all materialized ─ a 1-day in 10-year peak with two transmission contingencies ─ and California's commitments to demand reduction measures fail to yield expected benefits.

1. The CAISO's standards allow for use of SPS to mitigate the N-1-1 contingency and SDG&E is working now develop an SPS for the San Diego sub-area.

The transmission reliability standards allow the CAISO to use Special Protection Systems (SPS), including controlled load drop when planning for the loss of two or more electric system elements for a Category C contingency, such as the N-1-1 contingency studied in the CAISO's OTC study for San Diego.[136] Accordingly, because this is a viable transmission operations tool that could reduce need for conventional resources while maintaining reliability, the Commission should include SPS-based reductions when assessing SDG&E's need for the three PPTAs or any additional resources.

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[134] Trx. Vol. 3:22-25 (CAISO witness Sparks).

[135] Ex. 17 at 18-19 (Fagan Supplemental Testimony).

[136] Ex. 18 Attch. CC, Standard TPL-003-1a at page 1(for Category C contingency conditions, "[t]he controlled interruption of customer Demand … may be necessary to meet this standard), page 5 footnote c. See also Ex. 18 Attch. O (CAISO 2013 Local Capacity Technical Analysis) at 1 (figure 1 showing "planned and controlled load shedding allowed" under N-2 (simultaneous loss of two elements) or N-1-1 (sequential loss of two elements) contingencies.

Although the CAISO has refused to consider using an SPS to reduce SDG&E's local needs because it does not currently have an SPS in place, it also admitted that the time frame to design such a scheme is only one year.[137] Further, the CAISO's own original OTC study results indicate that the CAISO can – and did – consider an unspecified SPS of approximately 370 MW of load shedding to reduce the San Diego area LCR needs.[138] Since the CAISO has taken inconsistent positions on whether it can include an SPS in the San Diego Area, the Commission should consider the impacts of the SPS in this proceeding.

The Commission should also reduce the LCR needs to account for a potential SPS because SDG&E is already working toward obtaining formal recognition of an SPS for the SDG&E sub-area. Indeed, SDG&E claims that could reduce the San Diego sub-area LCR by 378 MW.[139] SDG&E has estimated the SPS would be in place by the summer of 2012 and WECC approval and recognition by the fall of 2012. SDG&E further indicated that it believes the CAISO would allow mitigation by load shedding in the San Diego area the event that SDG&E proposed SPS is in effect and has obtained formal recognition from the WECC.[140] SDG&E also admitted that controlled load drop is allowed under current reliability standards to mitigate the adverse consequences of an N-1-1 contingency event.[141] Although the CAISO has disagreed with considering load shedding in the N-1-1 scenario for 2020 due to concerns about the larger Imperial Valley area.[142] But as SDG&E argued, the CAISO's concerns about using contolled load drop for the San Diego sub-area should be addressed only after its SPS is in place.[143] If SDG&E is working to implement an acceptable load shed to reduce N-1-1 needs in 2013, that impact should also be considered for reducing LCR needs in 2020 or 2021.

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[137] Ex. 17 at 20 (Fagan Supplemental Testimony) Ex. 18 Attch. GG (CAISO Data Response to DRA-CAISO-16(b)) (DRA Supplemental Attachments).

[138] Ex. 10 at 3 (Sparks Supplemental Testimony).

[139] Ex. 18, Attch. K at 3.

[140] Id.

[141] Id. See also Ex. 17 at 21-22.

[142] Trx. Vol. 3 545:27-546:12 (CAISO witness Sparks).

[143] Ex. 18, Attch. K.

2. The CAISO's refusal to consider SPS cannot be justified based on unsubstantiated "system" benefits.

The Commission should reduce the LCR estimates to account for a potential SPS because it could eliminate the need for one or more costly, gas-fired power plants. The CAISO claims that it does not need to analyze the costs of using an SPS compared to the cost of procuring additional local generation because the latter costs are "offset by the benefits provided, both locally and system-wide."[144] This claim is wholly unsubstantiated, and in any event alleged "system" benefits are beyond the scope of this proceeding.

First, the CAISO has not submitted or conducted any cost-benefit analysis that actually compares the costs of controlled load drop versus procuring additional local generation.[145] Rather, the CAISO only testified that it was "a pretty safe assumption" that additional system needs would occur, beyond the "immediate reliability issue" of this proceeding, which is the local capacity requirements.[146] Such unsubstantiated and speculative benefits cannot provide the basis for approving the PPTAs, particularly when neither the CAISO nor SDG&E has submitted any evidence that the actual cost of instituting an SPS would be greater than the capacity costs of the PPTAs. The only costs before the Commission are the substantial yearly PPTA contract costs.[147]

Further, any potential system benefits from the PPTAs exceeds the scope of this proceeding. The PPTAs will impose substantial costs starting years before Encina retires, but their need is can only be justified if Encina is retired.[148] By contrast, if an SPS could achieve the same reliability as one or more of the PPTAs, then the PPTAs may not be cost-effective Commission should not approve them. Indeed, in addressing the foundational decision establishing the Commission's Resource Adequacy program, the Commission emphasized that

> [T]he traditional utility role in procurement included the responsibility to provide reliable service at least cost, and that this

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[144] Ex. 27 at 12 (Sparks Rebuttal Testimony).

[145] Id.

[146] Trx. Vol. 3 593:11-596:1 (CAISO witness Sparks).

[147] Ex. 4-C at 18 (DRA Testimony), Ex. 35-C.

[148] Ex. 4-C at 17-18, Ex. 35-C.

> is one of the 'same issues' of traditional resource procurement that [Resource Adequacy] seeks to address. Thus, the concept embodied in the phrase 'reliability at any cost' is not a policy option. Ultimately, measures that are proposed to promote greater grid reliability should be evaluated by weighing their expected costs against the value of their expected contribution to reliability.[149]

Indeed, in comments submitted on connection with the 2013 final LCR study, SDG&E stated that the "[CA]ISO's decision to reject use of controlled load drop for the [San Diego] Sub-area could result in significant additional procurement costs for all LSEs in the SDG&E service territory.[150] Given that the SDG&E SPS is expected to become available soon, the adequacy and cost-benefit analysis of using an SPS versus more generation could be weighed more fully in the next LTPP that addresses LCR needs. If the SPS turns out to not be a feasible or cost-effective option, then the Commission can authorize procurement to fill any gap created by assuming that an SPS will be available.

3. Assuming that an SPS is available to reduce LCR needs would eliminate the need for one or all of the PPTAs.

If the Commission considers the impact of a potential SPS to meet San Diego local area needs in 2020, it could eliminate the need for the Pio Pico and/or Quail Brush project. Applying an SPS would reduce the CAISO's estimates of LCR need by at least 378 MW to reflect the potential for using controlled load drop, and could be as high as 604 MW to meet a contingency caused by the loss of the Otay Mesa plant.[151] Applying a 378 MW reduction to the CAISO's estimated OTC needs would reduce the range of LCR needs from 0 MW (environmental case) to 276 MW (trajectory case), adjusted to 2020 values.[152] Thus, this adjustment alone ─ without considering any further impacts from demand management programs ─ shows that even under the highest potential need scenario, SDG&E does not need approval of all PPTAs.

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[149] D.05-10-042 at 7.

[150] Ex. 18, Attch. K at 2. \

[151] Ex. 17 at 23 (explaining how load shed would affect the LCR need) (Fagan Supplemental Testimony).

[152] See Ex. 17 Table RF-1 (OTC need of 654 MW for 2020 under trajectory case). 654 minus 378 equals 276 MW.

Further, as DRA's witness Mr. Fagan demonstrated, if the Commission uses SDG&E's analysis based on the CED's recent higher demand forecast but applies higher demand-side reductions consistent with the 2010 LTPP, applying an SPS increases the potential surplus in San Diego in 2020.[153] Thus, accounting for an SPS creates plenty of additional headroom to accommodate SDG&E's concerns that energy efficiency and demand response resource additions may not be as high over the planning horizon as estimated in the 2010 LTPP.

Finally, as this decision may set new precedents in how the Commission uses LCR studies for long-term planning, the Commission should require the CAISO to submit with future assessments sensitivity analyses that take into account potential Special Protection Schemes that could be implemented to mitigate the LCR needs under the controlling contingency. The Commission should also consider requiring the CAISO or the utility to submit cost-benefit-analyses to assist the Commission in assessing tradeoffs between relying on an SPS to provide for reliable grid operations under extreme operating contingencies compared to the cost of procuring new local generation capacity.

III. The Commission should not approve procurement for SDG&E based on potential needs for flexible system resources which have not yet been defined.

The issues of flexible capacity needs and resource characteristics that will meet those needs are currently being addressed in both the current RA proceeding and the concurrent LTPP proceeding. Authorizing the PPTAs based on their flexibility would be premature, given that the Commission has not adopted or defined what "flexible" resources are or set procurement targets based on the operational characteristics of resources.

First, the CAISO's renewable integration studies are predicted to be completed in 2013 and will inform next year's LTPP decisions on whether additional system-wide needs exist under Track 2, which will take into account any new resources that are authorized to meet local capacity needs.[154] These studies will help to better define and determine any actual need in the next ten years, which is critical for authorizing any procurement for new generation based on

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[153] See Ex. 17 at Table RF-3 (describing reductions to SDG&E's assessments if controlled load drop were used to reduce LCR in combination with demand side reductions, potential surplus would be over 500 MW.

[154] 2012 LTPP Scoping Memo at 10.

flexibility needs given the Commission's recent decision on the 2010 LTPP.[155] Thus, to authorize SDG&E to procure resources based on a claimed need for flexible resources would get ahead of the processes submitted in the settlement in the 2010 LTPP and approved by the Commission.[156]

Second, the recent Resource Adequacy Decision highlights the complexity and ongoing efforts by the Commission to examine flexible capacity. That decision ordered an ongoing process to consider issues related to flexible capacity, after a large consensus of parties concluded that none of flexibility proposals under consideration were sufficiently detailed or ready for implementation.[157] It also concludes that the 2012 LTPP proceeding will work "in coordination with Commission decisions on flexible capacity in this RA proceeding."[158] The RA decision makes it clear that a definition of flexibility must first be determined prior to requiring specific resource requirements, and a decision that defines flexibility is expected by the end of 2012. This forthcoming decision on flexibility will be the first step in "allowing or requiring utilities and/ or other LSEs to procure for local reliability needs."[159] The recent issuance of R.12-06-025 by the Commission provides clear evidence that it is premature for this application proceeding to rule on flexibility issues ahead of the ongoing RA and LTPP proceedings where the Commission is seeking resolution of this complicated issue.

IV. Even if the Commission approves the three PPTAs, it should not authorize any additional procurement for the San Diego Area in this proceeding.

Even if the Commission finds that the LCR need in 2020 excludes 450 MW (and thus approves the PPTAs), it should <u>not</u> grant SDG&E any additional procurement authorization at this time.

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[155] D.12-04-046 at 6 ("There is general agreement that further analysis is needed before any renewable integration resource need determination is made."), 11 ("The record clearly supports a conclusion that no new generation is needed by 2020…").

[156] <u>Id</u>. at 12 (Noting in approving deferment of the flexible resource need determination that "if there is no need to authorize procurement of generation, then there is no need to incur the costs for procurement of generation, meaning that deferral of that procurement results in lower rates.")

[157] D.12-06-025, Conclusion of Law No. 5 at 38.

[158] <u>Id</u>. at 13.

[159] <u>Id</u>. at 20.

There is a great deal of uncertainty whether SDG&E will actually need any more local resources before 2020. There is a substantial chance that SDG&E would have a surplus in local resources after the PPTAs come online, even if Encina is retired. The surplus could be very large if energy efficiency, demand response, and distributed generation resources materialize in greater quantities than SDG&E has forecasted.[160] There is, therefore, a very high chance that SDG&E will not need to conduct any more Requests for Offers (RFO) over the planning horizon. Yet SDG&E asks for permission to conduct another RFO immediately.[161] Granting additional procurement authorization in the face of these extreme uncertainties and outside of the Commission's LTPP processes would enhance regulatory uncertainty to everyone's detriment.

Numerous uncertainties that affect the estimated need (explored in sections above) will become clearer over the next couple of years and through the litigation efforts in the 2012 LTPP:

- the actual pace of economic recovery given that lower load resulting from an protracted sluggishness in the economy could substantially diminish the resource need in San Diego's area,
- the potential for Encina to achieve compliance with alternative mitigation measures that would allow continued operations and/or NRGs efforts to construct the Carlsbad Energy Center,
- the potential to use (and magnitude of) an SPS to reduce LCR needs in light of SDG&E's efforts to gain formal recognition of its SPS,
- the high possibility that further transmission upgrades will be approved in San Diego that could reduce the LCR,
- the possibility that California's many ratepayer-funded energy efficiency and demand response programs will provide expected benefits,
- what goals will be adopted for SDG&E to achieve the Governor's commitments to further increasing levels of distributed generation,
- whether additional procurement is needed to provide system flexibility and what attributes should be solicited and valued through an RFO,

[160] Ex. 15 at 8-9 (Table FG-1) (Ghazzagh Supplemental Testimony).

[161] Trx. Vol. 268:3-9, 269:26-270:2 (SDG&E Witness Anderson).

- interconnectedness of the San Diego and Southern California Edison service territories.[162]

Authorizing SDG&E to engage in more procurement now ─ to institute an RFO as a result of this application ─ would cause more regulatory and economic uncertainty in the future for SDG&E, developers, and intervenors. Parties to a later application for contract authorization would likely disagree whether the authorization was still "good", or had been superseded by later developments. "Updating" to make need estimates current based on the latest transmission, load, and resources assumptions would be necessary to determine if resulting contracts could be justified based on then-current estimates of local reliability need. Thus, authorizing SDG&E to go engage immediately in an RFO following this Application would put the cart before the horse and could raise the expectations of developers (who submit bids into an RFO) that a need for their projects exists that ultimately may not be justifiable. It would perpetuate the very problem we have seen in this proceeding, where an application for approval of PPTAs has morphed continuously into a mini-LTPP for San Diego alone and apart from the other LTPPs.

Indeed, SDG&E did not finalize and submit the PPTAs for approval for more than 4 years following the decision that allegedly authorized the need. SDG&E cannot reasonably claim that those 4 years resulted from Commission inaction or "regulatory lag," it is more likely due to changed circumstances: SDG&E's application here was originally based on a need authorization issued in December 2007 (D.07-12-052), but what followed that decision was "a fairly dramatic change in the economy, a fairly dramatic change in the load forecasts for the horizon" to 2015.[163] (Further, the authorization was conditional upon the Sunrise Powerlink not being built). Rather than perpetuating a cycle that gives SDG&E wide berth to keep developers, intervenors, and even the Commission guessing as to when it might finalize and submit projects that it receives authorization to purse, the Commission should withhold the authorization until the needs become more certain.

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[162] See Ex. 16 at 6 (Spencer Supplemental Testimony).

[163] Trx. Vol. 3 519:7-520:7 (DRA witness Fagan responding to ALJ question).

Both the Commission and the CAISO continuously look at longer-term procurement and transmission planning through annual or semi-annual cycles, and the needs at issue will become much more defined over the next few years.

Delaying further procurement authorization is also critical because of the ongoing studies and significant effort that the CAISO, Commission, and parties are devoting to better understanding and defining system flexibility needs. If the Commission determines that new resources are needed to meet system flexibility needs, those needs could be simultaneously satisfied by the same generation facilities. The most economical solution for ratepayers would result if SDG&E procure resources that simultaneously satisfy the LCR flexibility needs. Because the work to develop a better understanding of flexibility needs is ongoing and will continue into Track 2 of the 2012 LTPP cycle, the Commission should not authorize SDG&E to conduct an RFO until after the flexibility characteristics needs have been defined and thus can be incorporated into the RFO process and least-cost, best-fit evaluation of the results.

Finally, if demand-side management programs do not materialize as expected, demand grows faster than expected, or other transmission options are not available to reduce the LCR needs, history has shown that the Commission, the CAISO, and utility can work together to expeditiously mitigate emerging reliability concerns. For example, in the wake of prolonged and severs summer heat storms in California in July 2006, the Commission ordered SCE to build 5 peaking power units to provide additional capacity and grid-reliability benefits in time for the following summer.[164] Four peaker units were on-line and operational by the summer of 2007.[165] Further, the LCR needs analysis is based on planning for the retirement of the Encina plant; SDG&E's local needs are expected to be sufficient under the current "status quo."[166]

The CAISO could also (and may insist upon) maintaining operations at the Encina plant if necessary to maintain reliability in the interim while additional power plants are constructed.[167] It could easily be a more cost-effective approach to bridge any gap years using the existing

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[164] D.09-03-031 at 1-2, Findings of Fact No. 6.

[165] Id.

[166] Trx. Vol. 4 612:17-613:2 (CAISO witness Sparks).

[167] See Trx. Vol. 177:12-15 (SDG&E witness Anderson), Trx. Vol. 3 584:7-585:27 (CAISO witness Sparks).

generation rather than over-procuring and committing SDG&E's ratepayers to long-term capacity for plants that very well may not be needed. Thus, if the reliability-based needs do exceed prudent planning estimates that incorporate demand reduction measures required under the State's loading order, the CAISO and SDG&E could rely, for the time needed, on the existing generation.

For all of these reasons it is crucial that the Commission not authorize SDG&E to conduct any additional procurement at this time to meet alleged local capacity needs that are unlikely to arise, if at all, until the end of the current planning horizon.

CONCLUSION

For the reasons stated above, the Commission should adopt the recommendations set forth in DRA's Summary of Recommendations at the beginning of the brief.

Respectfully submitted,

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July 13, 2012