Application No.: R.12-03-014
Witness: Julia May
Exhibit No.:

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

PREPARED DIRECT TESTIMONY OF JULIA MAY ON BEHALF OF THE CALIFORNIA ENVIRONMENTAL JUSTICE ALLIANCE REGARDING SONGS RETIREMENT, TRACK IV

ERRATA NOVEMBER 5, 2013

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA
September 30, 2013

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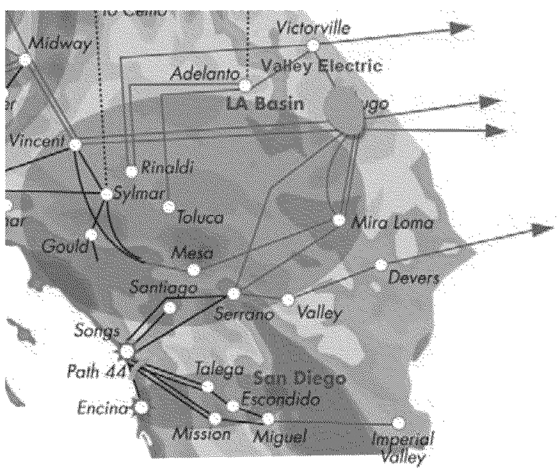
I. Summary: The studies of LA & San Diego needs due to SONGS retirement are missing substantial resources that would eliminate generation need

I am a Senior Scientist at Communities for a Better Environment (CBE), which is a member organization of the California Environmental Justice Alliance (CEJA). My background includes a bachelor's degree in Electrical Engineering and over 25 years providing engineering and policy analysis in state and local regulatory proceedings regarding industrial regulation, permitting, electricity planning, renewable energy, transmission alternatives, energy efficiency, and air pollution assessment. These include proceedings before the CEC, CPUC, CARB, SCAQMD, and BAAQMD[1] in California, as well as other state and tribal regions. I have provided engineering analysis on behalf of CBE, other non-profit environmental organizations, and trade unions. A true and current copy of my CV is appended hereto as Attachment A.

This report is produced on behalf of CEJA and evaluates the basis and conclusions of modeling and evaluations by the California Independent System Operator (CAISO), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E) regarding whether there is any new generation need due to retirement of the San Onofre Nuclear Generating Station (SONGS), in Track 4 of the Long Term Procurement Planning (LTPP) of the California Public Utilities Commission (CPUC).

Below is a map of the LA Basin and San Diego study area evaluated in the CAISO 2012-2013 Transmission Plan: [2]



[1] Respectively the California Energy Commission, California Public Utilities Commission, California Air Resources Board, South Coast Air Quality Management District, and Bay Area Air Quality Management District.

[2] California Independent Systems Operator, 2012-2013 Transmission Plan, at 127 (Mar. 20, 2013), *available at* http://www.caiso.com/Documents/BoardApproved2012-2013TransmissionPlan.pdf [hereinafter CAISO 2012-2013 Transmission Plan].

I conclude that there is no new generation need due to SONGS retirement, because:

- CAISO's modeling starts with very conservative assumptions including:
  - load during the hottest day in ten years;
  - three major transmission lines down (Sunrise, Southwest, and CFE);
  - an additional 2.5% reserve margin (adding 700 MW in 2022); and
  - no load drop.
- The updated 2013 CEC demand forecast for the LA Basin and San Diego for 2022 is 1,320-3,200 MW lower than the 2012 CEC forecast CAISO modeled;
- Transmission improvements, especially reactive support, (not yet modeled by CAISO), were found to reduce need by at least 1,500 MW;
- Preferred resources including ~~50 MW of Energy Storage,~~ 997 MW of DR, and 496 MW of DG that the CPUC Scoping Memo assumed would be utilized were only applied to extreme Category D, not Category C, contingencies; and
- New CPUC Energy Storage proceeding targets of over 600 megawatts for the LA Basin and San Diego, identified for 2020, should be added to Track 4.

Even after the extremely conservative starting point, need is still zero if the missing resources discussed in detail below are included. These missing resources are summarized in Table 1 below. If any new generation is considered, it should be limited to preferred resources.

Importantly, CAISO has *not* requested new procurement approval for the approximately 2500 MW of need it identified, instead proposing to wait until after 2013/2014 transmission planning to consider added mitigation.[3] Although SCE found no generation need,[4] it nevertheless requested approval of about 500 MW of new generation (as did SDG&E) simply because *CAISO* had a higher expectation of need. CAISO's estimate, however, is based on incomplete testimony by its own admission; its complete testimony may well concur with SCE's conclusion of no need. I disagree with SCE's and SDG&E's proposals for procurement because when transmission fixes, CPUC-assumed resources, and other available preferred resources are added, need disappears.

[3] California Independent System Operator, Track 4 Testimony of Robert Sparks on Behalf of the California Independent System Operator Corporation, at 31:1-4 (Aug. 5, 2013) [hereinafter CAISO Track 4 Testimony].
[4] Southern Claifornia Edison, Track 4 Testimony of Southern California Edison Before the CPUC at 3:10-16 (August 26, 2013) [hereinafter SCE Track 4 Testimony].

Table 1: Summary of resources left out of CAISO SONGS-retirement results

Notes on CAISO's conservative starting point, adding to reserve			
► Peak demand during the worst year in ten (1-in-10) (not required by NERC)			
► Further 2.5% reserve margin not required by NERC,[5] results in **adding 704 MW in 2022** (670 MW in 2018)			
► Three major transmission lines down (not two) □ Southwest, Sunrise, and CFE, **with no load drop**			
Missing Resources	2018	2022	**2022** (MW)
Impact of Lower CEC 2013 Load Forecast			
CEC's 2013 peak forecast for 2022 is lower by 1,320 (baseline) to 3,200MW lower (with more EE) than the 2012 forecast for 2022, also lower for 2018	NO	NO	1,320-3,200
Transmission fixes left out			
550 MVAR reactive support at SONGS	NO	NO	300
HB3&4 converted to 2x140 MVAR Synchronous Condensers (CAISO did not quantify reduced MW of need), OR if repowered, 939 MW reduced need in real power, plus reactive support (included by CAISO for 2018 but not 2022)	□	NO	Reduced gen through 280MVAR or 939MW gen.
Mesa Loop-In proposed by SCE	NO	NO	1,200
Upgrade Ellis-Johanna & Ellis-Santiago 230 kV lines to conductor rating (not yet ISO-approved – SCE proposal) - (Removes thermal overloads)	NO	NO	Reduces need
PV Smart Inverters (capable of providing reactive support)	NO	NO	Reduces need
Additional projects are likely in the future	NO	NO	Likely more
CPUC Scoping preferred resources missing + New Storage Targets			
~~Scoping's 50 MW Energy Storage~~	~~NO~~	~~NO~~	~~50~~
Scoping's Demand Response (DR): CAISO did not apply CPUC assumption of 997 MW to Category C contingency, but applied to Category D	NO	NO	997
Scoping's Small scale customer-side PV assumptions in CPUC Revised Scoping 2018: 216MW + 2022: 278MW, If these are additive, total is 496MW	NO	NO	496
Reduced transmission losses due to use of scoping assumption distributed resources (including EE& DR). (DG avoided losses also need calculating)			59 to 129
New Energy Storage Target: 580 MW 2020 target for SCE, using 77% as LA Basin ratio, (447MW) + 165 MW for SDG&E = 612 MW total by 2020	NO	NO	>600
Existing sources that could reduce need			
Cabrillo Peaker 188MW & San Diego Navy CHP 88 MW □ delay retirement			Potential 276
Total of Above Missing Resources - Conservatively discounted by 1/3			At least 3549- 4671
Preferred resources could meet any additional new generation considered			
State goals for EE, DR, & DG are considerably higher than scoping assumptions. Given these goals, the loading order priority, the necessity of GHG reductions, the low cost of EE and DR, and rapidly declining cost of PV DG, any consideration for new generation should be limited to preferred resources.	NO	NO	Large added Potential

[5] North American Electric Reliability Corporation.

II. CAISO's analysis does not yet include certain key transmission fixes that would reduce need. CAISO agrees that consideration of transmission fixes is prudent.

Transmission improvements, especially those that provide reactive support,[6] greatly reduce the need for new or replacement generation for SONGS, as identified by CAISO[7] and discussed in more detail below. CAISO included several new transmission improvements in the Track 4 analysis, all of which were approved by CAISO's Board in the 2012-2013 Transmission Plan and directed by the Commission in the Revised Scoping Decision.

However, CAISO's last transmission plan was completed before it knew that SONGS was being permanently retired, so transmission options identified by CAISO but not yet approved by its Board were left out of the Track 4 study. Thus, the new generation needs in CAISO's Opening Testimony are higher than they would be if these improvements were included. SCE's and SDG&E's testimony also identified transmission improvements beyond those considered by CAISO that could reduce even further the generation need within the LA Basin and San Diego.[8] The Commission's staff has also previously stated the need for CAISO to perform additional analysis on transmission options as a way to reduce needs for new generation.[9]

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[6] Reactive power can be difficult to explain without providing charts and diagrams of AC power, but a presentation by Oakridge National Laboratories *(Reactive Power and Importance to Bulk Power Systems)* provides a basic summary: "*Reactive power (vars) is required to maintain the voltage to deliver active power (watts) through transmission lines. Motor loads and other loads require reactive power to convert the flow of electrons into useful work. When there is not enough reactive power, the voltage sags down and it is not possible to push the power demanded by loads through the lines." "When voltage and current are not in phase or in synch, there are two components, --Real or active power is measured in Watts, --Reactive (sometimes referred to as imaginary)power is measured in Vars,[volt-amperes reactive], --The combination (vector product) is Complex Power or Apparent Power, -- The term "Power" normally refers to active power"* Reactive power doesn't travel far, and so must be supported locally. (A crude analogy for laypeople that has been used is that a baseball's forward motion is like active power, the height of the arc is like reactive power – necessary to keep the ball in the air, but not part of its forward power.) *See* Reactive Power and Importance to Bulk Power System, Oak Ridge National Laboratory http://www.ornl.gov/sci/decc/RP%20Definitions/Reactive%20Power%20Overview_jpeg.pdf

[7] *See e.g.*, California Public Utilites Commission, Comments of the Staff of the California Public Utilities Commission on the Draft Study Plan, at 7-8 (Mar. 14, 2012), *available at* http://www.caiso.com/Documents/CPUCComments-Draft2012-2013StudyPlan.pdf [hereinafter CPUC Staff Comments on Draft Study Plan].

[8] SCE Track 4 Testimony, at 1:14-16; R.12-03-014, John M. Jontry, Prepared Track 4 Testimony of San Diego Gas & Electric Company, at 4:19-5:11 (Aug. 26, 2013) [hereinafter SDG&E Jontry Track 4 Testimony].

[9] CPUC Staff Comments on Draft Study Plan, at 7-8 ("Due to conflicting OTC requirements and local air emissions requirements, there arises the necessity to perform additional analysis related to compliance that may not just be generation retirement or repowering. Transmission improvements specifically to reduce reliance on OTC plants as well as particular locations in the transmission topology (such as LCR subareas) are required in order to inform compliance alternatives for generating asset owners who have the choice of either retirement inside the current ISO transmission topology, repowering inside the current ISO topology, or undertaking another alternative such as refitting their water intake structures. **Most importantly, transmission improvements for a future ISO**

CAISO agrees with the need to consider additional transmission mitigation before determining procurement need and proposes waiting until after the next Transmission Planning Process (TPP) to decide whether there is a need for more procurement. Given this position, CAISO understandably requested a delay of the Commission's decision, stating that it has not completed its transmission analysis.[10]

The Commission's Revised Scoping Memo prescribes that CAISO should include all ISO-approved transmission upgrades in the Track 4 modeling,[11] but the Memo does not specify the reactive power assumptions CAISO should use. As such, the Scoping Memo did not account for the fact that SONGS' permanent retirement created a need for reactive support.

A. *CAISO found reactive support was a key need to mitigate SONGS retirement, but available options for additional support are not yet included in the study*

CAISO's 2013 Local Capacity Technical Analysis Addendum (LCT Analysis Addendum)[12] determined that the absence of SONGS created voltage support deficiencies in both the Los Angeles Basin[13] and in the San Diego local capacity areas.[14] CAISO therefore recommended "[a] mixture of dynamic (i.e. synchronous condensers) and static (shunt capacitors) reactive support … in order to satisfy fast voltage recovery need at the SONGS 230 kV bus without causing further operational concerns…"[15] CAISO's 2012-2013 Transmission Plan also determined that, in many places, reactive support is key to providing reliability in the

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transmission topology that reduce LCR requirements in sub-areas also needs to be examined, which the ISO has not addressed in a systematic manner. It is critical to be able to evaluate these tradeoffs in order to minimize ratepayer costs and make the most efficient decisions possible about future resource investment.").

[10] CAISO Track 4 Testimony, at 31:1-7 (*"The ISO recommends that the Commission wait to make a decision about the need for additional resources until the ISO has completed its studies of potential transmission mitigation solutions (including the need for additional reactive support). With that information, the Commission can then consider the appropriate resource "mix" that can meet the local reliability needs arising from the SONGS retirement. Such a mix can include additional preferred resources and other alternatives to conventional resources, depending on location and effectiveness."*).

[11] California Public Utilities Commission, Revised Scoping Ruling and Memo of the Assigned Commissioner and Administrative Law Judge, Attachment A, at 13 (May 21, 2013) [hereinafter CPUC Revised Scoping Memo].

[12] California Independent Systems Operator, 2013 Local Capacity Technical Analysis Addendum to the Final Report and Study Results: Absence of San Onofre Nuclear Generating Station (SONGS) (Aug. 20, 2012), *available at* http://www.caiso.com/Documents/Addendum-Final2013LocalCapacityTechnicalStudyReportAug20_2012.pdf [hereinafter CAISO LCT Analysis Addendum)].

[13] CAISO LCT Analysis Addendum, at 3 *("Overall the LA Basin LCR needs are now driven by a new overlapping Category C contingency in the San Diego's electric system, due to voltage support needs that arise in the area.")*.

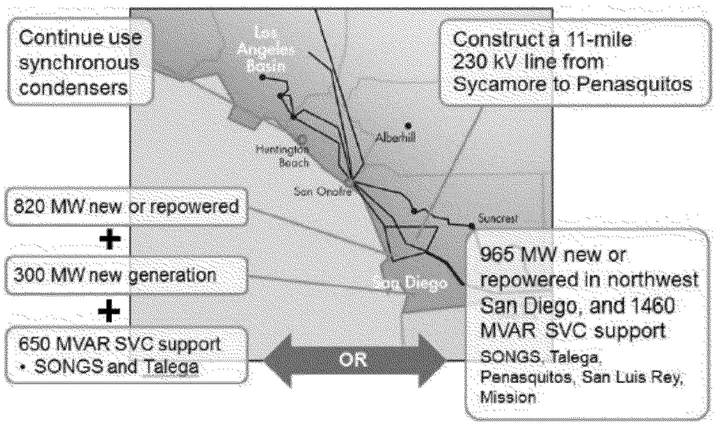
[14] CAISO LCT Analysis Addendum, at 3 *("The San Diego sub-area requirements have increased significantly, by 966 MW, and the San Diego–Imperial Valley area requirements have increased also by 447 MW, due to voltage support needs in the absence of SONGS.")*.

[15] CAISO LCT Analysis Addendum, at 4-5.

absence of SONGS: "A total of approximately 700 MVAR of dynamic reactive support in both LA Basin and San Diego areas provides mitigation for the absence of SONGS in a wide range of conditions . . ."[16]

CAISO's Track 4 opening testimony emphasized reactive support as key to replace what was formerly provided by SONGS.[17] CAISO also confirmed the importance of considering reactive power at a July 15, 2013 Joint Workshop on reliability needs related to SONGS retirement which described throughout the presentation the need for additional reactive support;[18] for example: 650-1460 MVAR for 2018 and also for 2022, in addition to synchronous condensers at Huntington Beach:[19]

Figure 3.5-3: Mid-term mitigation alternatives for loss of SONGS



The CAISO Joint Workshop slides also summarized mitigation needed for 2022, which are to be added to the 2018 needs:[20]

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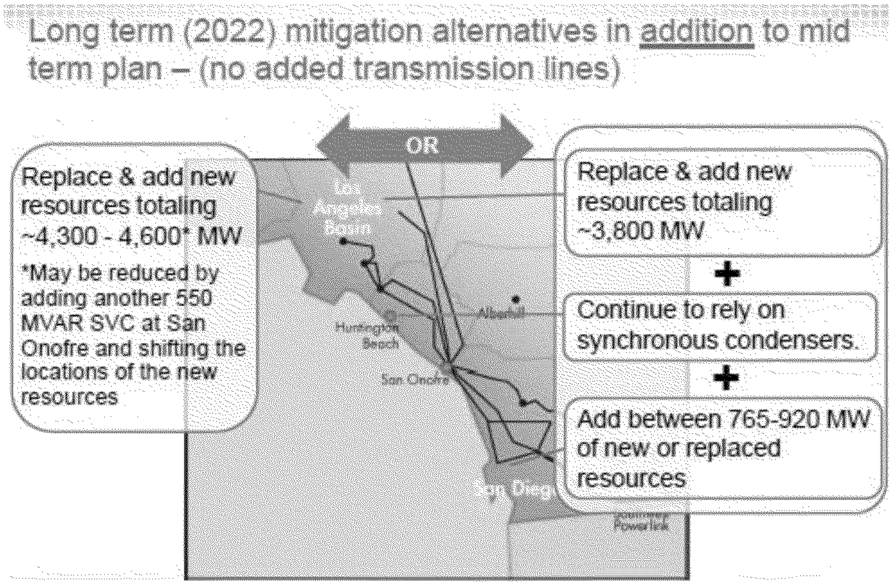
[16] CAISO 2012-2013 Transmission Plan, at 195.
[17] *See e.g.,* CAISO Track 4 Testimony, at 16:4-18.
[18] California Independent Systems Operator, CEC/CPUC Joint Workshop Electricity Infrastructure Issues Relating from SONGS Closure: ISO 2013 Transmission Plan Nuclear Generation Backup Plan Studies (SONGS) (July 15, 2013), *available at* http://www.energy.ca.gov/2013_energypolicy/documents/2013-07-15_workshop/presentations/04A_CAISO_SONGS_Studies_7-15-13.pdf [hereinafter CAISO Presentation CEC/CPUC SONGS Workshop]. Additional reactive support is identified as MVARs, reactive support, voltage support, capacitors, synchronous condensers, or SVC support throughout the presentation, within the CAISO portion, and also in the slides included in the set by SCE and SDG&E that are attached to the CAISO slides.
[19] CAISO Presentation CEC/CPUC Joint SONGS Workshop, at 6.
[20] CAISO Presentation CEC/CPUC Joint SONGS Workshop, at 7.



Note that the asterisk above states that new generation need could be reduced for 2022 "by adding another 550 MVAR [Static Var Compensators] at San Onofre." This reactive support was not included in the 2022 results of CAISO's Track 4 Opening Testimony, but CAISO's 2nd set of data responses[21] informs us that this would reduce need by 300 MW:

> **<u>Request No. 4.</u>**
>
> Mr. Pettingill's July 15, 2013 slide 7 for the CEC/CPUC workshop states that the MW need in 2022 "[m]ay be reduced by adding another 550 MVAR at San Onofre and shifting the location of the new resources." Please explain how much this additional MVAR will reduce MW need and where CAISO proposes shifting the location of the new resources. . . .
>
> **<u>ISO RESPONSE TO No. 4.</u>**
>
> *The specific sensitivity of adding an additional 550 MVAR dynamic reactive support at SONGS was studied in the 2012/2013 Transmission Plan and could help reduce the amount of resource needs by about 300 MW as Table 3.5 of the ISO 2012/2013 Transmission Plan indicated.*

The 2018 analysis on SONGS retirement in the 2012-2013 Transmission Plan described the following needs for reactive support, and that reactive support targeted to key areas was particularly effective in mitigating voltage and loading concerns:[22]

> Also, during the course of the study the ISO discovered that two particular mitigation measures were highly effective at mitigating a large number of the loading and

[21] California Independent System Operator, ISO Response to the Second Set of Data Requests Related to Track 4 of the Division of Ratepayer Advocates; California Environmental Justice Alliance; Sierra Club, CA; and Clean Coalition in Docket No. R.12-03-014, Request No. 4 (Aug. 8, 2013) (emphasis added).
[22] CAISO 2012-2013 Transmission Plan, at 172-73.

voltage concerns. It was found that continued reactive support was needed at Huntington Beach in both identified mitigation scenarios. . . .

- The ISO assumed that the Huntington Beach synchronous condensers will be available for the intermediate (i.e., 2018) time frame and will assume their continued use or equivalent support. This was identified as part of the need for the SONGS absence scenario for summer 2013.
- Installation of 80 MVAR of shunt capacitor each for Johanna and Santiago Substations, and 160 MVAR of shunt caps for Viejo Substation. This was identified as part of the mitigation for the SONGS absence scenario for summer 2013.

In addition, CAISO stated that the reactive support provided by the Huntington Beach condensers is needed in the event of an overlapping outage on both the Sunrise Powerlink and the Southwest Powerlink, which is the outage assumed in Track 4.[23]

The Johanna, Santiago, and Viejo shunt capacitors are completed and included in CAISO's modeling.[24] The Huntington Beach synchronous condensers[25] are also completed according to SCE's presentation at the joint workshop[26] and to a data response from CAISO.[27] However, while the Huntington Beach condensers are assumed by CAISO to be available in the 2018 SONGS-out assessment, they are not included in the Track 4 2022 assumptions.[28] CAISO has stated this is because Huntington Beach may be repowered,[29] but neither the completed Huntington Beach synchronous condensers nor the potential repowering of Huntington Beach

[23] California Independent System Operator, Response of the California Independent System Operator Corporation to the First Set of Data Requests Related to Track 4 of the Division of Ratepayer Advocates; California Environmental Justice Alliance; Sierra Club, CA; and Clean Coalition, Request No. 15 (July 12, 2013).
[24] California Independent System Operator, Response of the California Independent System Operator Corporation to the First Set of Data Requests Related to Track 4 of the Division of Ratepayer Advocates; California Environmental Justice Alliance; Sierra Club, CA; and Clean Coalition, Request No. 2 (July 12, 2013).
[25] Synchronous Condensers are machines designed exclusively to provide reactive power support, at the receiving end of long transmission lines, in important substations, and in conjunction with HVDC converter stations, reactive power output is continuously controllable.
[26] Southern California Edison, SCE Reliability Considerations, at 16 (July 15, 2013), *available at* http://www.energy.ca.gov/2013_energypolicy/documents/2013-07-15_workshop/presentations/04B_SCE_SONGS_Reliability_7-15-13.pdf.
[27] California Independent System Operator, Response of the California Independent System Operator Corporation to the First Set of Data Requests Related to Track 4 of the Division of Ratepayer Advocates; California Environmental Justice Alliance; Sierra Club, CA; and Clean Coalition, Request No. 1 (July 12, 2013).
[28] CAISO Track 4 Testimony, at 9; California Independent System Operator, Response of the California Independent System Operator Corporation to the First Set of Data Requests Related to Track 4 of the Division of Ratepayer Advocates; California Environmental Justice Alliance; Sierra Club, CA; and Clean Coalition, Request No. 1 (July 12, 2013).
[29] California Independent System Operator, Response of the California Independent System Operator Corporation to the First Set of Data Requests Related to Track 4 of the Division of Ratepayer Advocates; California Environmental Justice Alliance; Sierra Club, CA; and Clean Coalition (July 12, 2013).

are included in 2022 modeling. CAISO's 2nd set of data responses[30] responded to a question about why it assumed neither would be available:

> **<u>Request No. 9.</u>**
> Does CAISO assume that AES has constructed generation at the Huntington Beach site in 2022? If not, why does CAISO assume that the condensers at Huntington Beach will not be operating in 2022? What impact does the assumption that the condensers are not operating have on the generation needs identified in the 2012-2013 TPP.
>
> **<u>ISO RESPONSE TO No. 9.</u>**
> ***The ISO does not explicitly assume any particular generation project will be built unless permitting and contracting information supports that assumption.*** *Based on the information which AES submitted at the CEC for environmental permit review for the Huntington Beach Energy Project (http://www.energy.ca.gov/sitingcases/huntington_beach_energy/index.html), the ISO assumes that AES could proceed with the repowering plan to comply with the State Water Resources Control Board's Policy on OTC Plants by the end of 2020 time frame. If AES proceeds and completes the repowering project, new non-OTC units would provide the same dynamic reactive support in addition to real power.*

The analysis should either assume that Huntington Beach is repowered, or that the synchronous condensers are available for 2022. Accordingly, CAISO should either include the reduced megawatts of need provided by the two 140 MVAR synchronous condensers which reduce overall need, or include the 939 MW of repowered Huntington Beach resources including associated reactive support, but should not leave out both. CAISO could not provide an estimate of the reduced megawatts of need provided by this reactive support but as these were found to be at an effective location for SONGS reactive support replacement, they would undeniably reduce need. The 2013-2014 Transmission Plan could provide this information.

CAISO has stated that it only approved reactive support additions at two substations out of the ones analyzed because it did not know at the time of the Transmission Plan that SONGS was being permanently retired.[31] Because reactive support is so important for mitigating the SONGS retirement and not all available and practical solutions have been modeled, it is only

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[30] California Independent System Operator, ISO Response to the Second Set of Data Requests Related to Track 4 of the Division of Ratepayer Advocates; California Environmental Justice Alliance; Sierra Club, CA; and Clean Coalition in Docket No. R.12-03-014, Request No. 9 (Aug. 8, 2013) (emphasis added).

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

reasonable that these be included and modeled, and the procurement decision be delayed until afterward. It would not make sense to procure additional gas resources that could be filled by reactive support. Indeed, both SCE and SDG&E concur that reactive support and transmission improvements are key to replace SONGS.[32]

B. Other transmission fixes can reduce generation need

CAISO's 2012-2013 Transmission Plan included a chapter regarding grid reliability if SONGS were absent. Two tables (3.5-10 and 3.5-11) summarized generation needed, with additional transmission added into the second table.[33] Excerpts from these tables show reduced need for generation when transmission is added:

CAISO Transmission Plan Table 3.5-10 excerpts
- Summary of generation options

	2018: MW	2022: MW	Total MW
Generation Alt. 1	920	4315	**5235**
Generation Alt. 2	965	4740	**5705**

CAISO Transmission Plan Table 3.5-11 excerpts
Summary of combined transmission & generation alternatives

Gen. / Trans. Alt. 1	1120	3375	**4495**
Gen. / Trans. Alt. 2	965	3530	**4495**

When transmission fixes were added by CAISO in Table 3.5-11, the megawatt values needed were lowered by 740 MW and 1210 MW respectively.

In another example of transmission fixes reducing generation need, a comment letter written by SCE to the CEC for the Joint Taskforce on SONGS retirement, and SCE testimony identified the Mesa Loop-In as an additional project not included in CAISO's modeling[34] since it is still in development. The Mesa Loop-In would substantially reduce generation need in the LA Basin:

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[32] *See e.g.*, SCE Track 4 Testimony, at 49:6-9; SDG&E Jontry Track 4 Testimony 7:14-19, 14:9-11.
[33] CAISO 2012-2013 Transmission Plan, at 185-88 *("The following transmission line was modeled as common mitigation for the combined transmission & generation alternatives: Construct a new 65-mile 500kV line between Alberhill and Suncrest Substation with 70 percent compensation to reduce reactive power losses contributing to voltage stability concerns during contingencies because of high flows from the SCE to the SDG&E electric system.").*
[34] California Independent System Operator, Re: ISO Response to the First Set of Data Requests Related to Track 4 of Southern California Edison Company in Docket No. R.12-03-014, Request No. 5 (Aug. 21, 2013) ("This need does not assume the addition of the potential Mesa Loop-In.).

> In providing a new 500 kV substation to serve western Los Angeles Basin (LA Basin), the Mesa Loop-in Project will provide increased margin to the electric system. It will also provide for a significant reduction in the amount of generation that would otherwise be required in the western LA Basin and provide relief to the west of Serrano Substation corridor. The project scope for Mesa Loop-in has limited impact to the public since the vast majority of work is at an existing SCE substation and within SCE owned land. [35]

As such, SCE endorsed the project and decided to take the next step in its development:

> Given the urgent need for new resources, SCE will pursue construction of…the Mesa Loop-In, through requests to the CAISO and through an application to the CPUC. [36]

SCE testimony finds the Mesa Loop-In project would reduce generation need in the LA Basin by 1,200 MW.[37] Furthermore, SCE stated that it planned to submit the Mesa Loop-In project for approval by September 16, 2013.[38] SCE testimony also identified another regional transmission concept between LA and San Diego, to better share resources, which could further reduce need.[39]

The September 9th CEC/CPUC workshop slideshow also identified many transmission projects as potential mitigation for SONGS retirement:[40]

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[35] Letter from Manuel Alvarez, Manager, Regulatory Policy and Affairs, Southern California Edison Company to Mike Jaske, California Energy Commission, Re: Docket No. 13-IEP-1L: Comments on Joint Workshop on Electricity Infrastructure Issues Resulting from SONGS Retirement, at 3 (July 29, 2013), *available at* http://www.energy.ca.gov/2013_energypolicy/documents/2013-07-15_workshop/comments/SCE_Comments_on_Workshop_on_Electricity_Infrastructure_Issues_Resulting_from_SONGS_Retirement_2013-07-29_TN-71750.pdf.

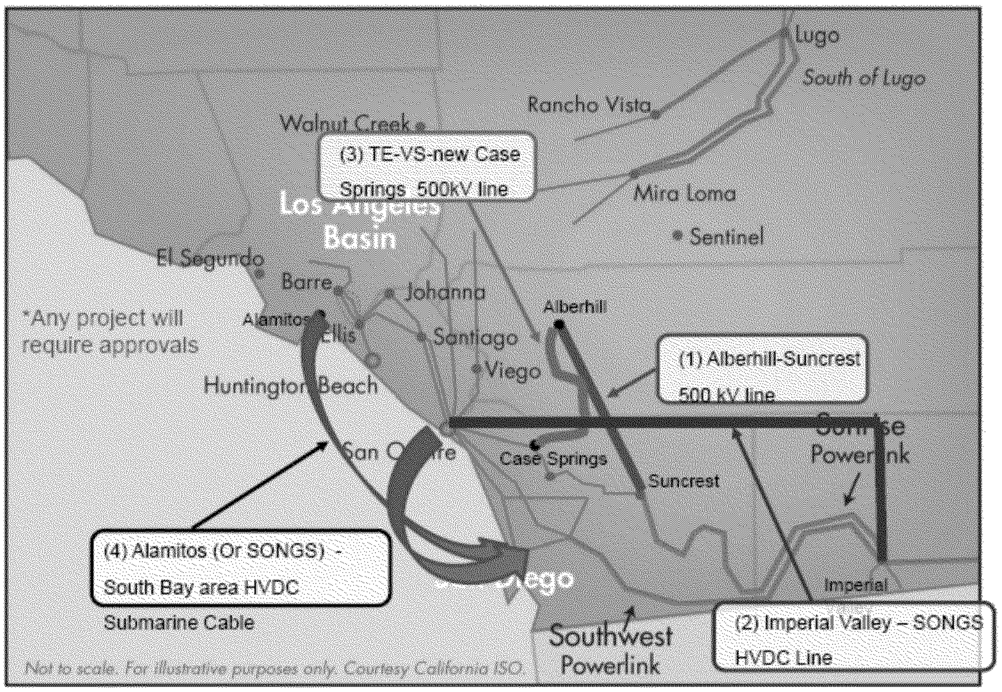
[36] SCE Track 4 Testimony, at 4:16-18 (Aug. 26, 2013).

[37] SCE Track 4 Testimony, at 36:8-9.

[38] Southern California Edison Company, Data Request Set CEJA_DRA_Sierra Club-SCE-002, at 2, Response to Question 2 (Sept. 5, 2013).

[39] SCE Track 4 Testimony, at 9.

[40] CAISO Presentation CEC/CPUC Joint SONGS Workshop, at 12.



With general agreement between CAISO, SCE, SDG&E, the Commission, and others that additional transmission improvements can substantially reduce local capacity needs, the Commission should make every attempt to fully study each and every proposed improvement before making its decision in this proceeding.

C. PV Smart Inverters can provide reactive support and other grid reliability characteristics, instead of necessitating additional support

The ability of Smart PV Inverters to provide grid support including reactive support and fault ride-through capability has been found by the CPUC to be a demonstrated practice in Europe,[41] but barriers exist here. SDG&E recently highlighted a call for requirements for installation of Smart Inverters on all new solar generators:[42]

> The Western Electric Industry Leaders (WEIL) Group is urging the installation of "smart inverters" on all new solar generators in the region to ensure the smooth integration of these environmentally friendly resources onto the electric grid. *This vital technology would allow the effective integration of these solar installations by providing the necessary voltage support* for these intermittent resources, which can cause power quality problems and reliability impacts because of fluctuations in their

[41] *See e.g.,* California Public Utilities Commission, Advanced Inverter Technologies Report: Grid Planning and Reliability, at ii (Jan. 18, 2013) *available at* http://www.cpuc.ca.gov/NR/rdonlyres/6B8A077D-ABA8-449B-8DD4-CA5E3428D459/0/CPUCAdvancedInverterReport2013FINAL.pdf .

[42] San Diego Gas & Electric Company, The Western Electric Industry Leaders (WEIL) Group Urges the Adoption of Smart Inverters On All New Solar Generators (Aug. 7, 2013), *available at* http://www.sdge.com/newsroom/press-releases/2013-08-07/weil-group-urges-adoption-smart-inverters (emphasis added).

> generation output. *The smart inverters would help ensure the integrity and reliability of the overall electrical system and enable the increased use of clean renewable energy for the benefit of the community.*

SDG&E's President and COO, Mike Niggli, added:[43]

> These smart inverters will help us ensure that we have the right voltage levels, that we have a smooth integration with the grid and that these can ride through disturbances very similar to what other power plants can do on the system right now.

The call for the integration of PV Smart Inverters is not exclusive to SDG&E; an industry whitepaper describes the additional values of Smart Inverters:[44]

> As the intelligent node in solar electric power generation, a utility's ability to communicate with and exert control over distributed inverters facilitates effective integration of high-penetration PV power generation into the grid. *These control capabilities include ramp rate, curtailment, power factor (volts-amp reactive support) and on/off functionality.* The ability to remotely control an inverter's output characteristics *minimizes the adverse impacts of solar power as an intermittent source of energy*. The additional ability of a utility to treat distributed generation as an aggregate resource to improve power quality and regulate voltage on the grid facilitates PV penetration rates that can far exceed what is feasible today. This real-time, two way communications capability, coupled with a base-line set of controls, has laid a framework for a new set of interactive Smart Grid support features for the utility.

CAISO has based many of its arguments for new gas on its ability to provide reactive support, fast ramp rates, etc. Now, however, it is confirmed that rooftop solar has the capability to provide this in a distributed manner when Smart Inverters are required in the infrastructure. The current barriers to their inclusion need to be addressed, including setting standards and requirements for them. Given the long lead times in the LTPP process, this seems very feasible and desirable since the widespread addition of Smart Inverters allows for a more environmentally sound grid than new gas resources, in addition to being consistent with loading order requirements.

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[43] KFMB-TV CBS8, SDG&E Pushes for Smart Inverters on Solar Generators (Aug. 7, 2013), *available at* http://www.cbs8.com/story/23078312/sdge-pushes-for-smart-inverters-on-solar-generators.

[44] Advanced Energy, Laying the Foundation for the Grid-Tied Smart Inverter of the Future, at 5 (2011), *available at* http://solarenergy.advanced-energy.com/upload/File/White_Papers/SEGIS-Laying%20the%20Foundation-2-FINAL.pdf (emphasis added).

III. CAISO left out preferred resources required by CPUC assumptions, underestimated transmission loss avoidance achieved by local preferred resources, and left out existing resources that could fill need

CAISO's opening testimony is confusing in parts, in that it claims to rely on CPUC-required assumptions or sometimes states it considered these assumptions to a certain extent, but these assumptions are frequently not actually used to address needs. Because the modeling is missing resources required in the CPUC assumptions, the modeling results identify far more need than actually exists. However, importantly, CAISO is not asking for procurement of the need it identified until after the next TPP when further transmission improvements will be considered.

A. Demand response set by the CPUC was not used for Category C contingencies

CAISO has failed to take into account the 997 MW of demand response resources for 2018 and 2022 that the Scoping Memo Attachment A instructed it to use to reduce need for N-1-1 contingencies.[45] Those 997 MW were specifically earmarked for the SONGS study area out of about 1330 MW for the broader SCE and SDG&E areas.[46] Instead, CAISO asserted:

> The additional DR amount of 997 MW, based on the Revised Scoping Ruling, would be utilized to mitigate reliability concerns in the post second contingency condition. *This would be applied to contingencies that are of Category D.*[47]

The CPUC's instructions in Attachment A direct that these resources be utilized to address the second contingency (Category C)[48] – not "post second contingency" – which is only reasonable since the Commission is not in the business of ensuring sufficient resources for extreme Category D events:[49]

> "Second Contingency" resources are not modeled but would be accounted for as potential resources *to address any residual need identified by a second contingency condition* in the studies.

This should be corrected by subtracting the 997 MW of DR resources from the generation need finding in CAISO's study, as summarized in Table 1 of this report. CAISO should be

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[45] N-1-1: Outage of a transmission element followed by the outage of another transmission element (also N-1/N-1)
[46] CPUC Revised Scoping Memo, Attachment A, at 7.
[47] CAISO Track 4 Testimony, at 7 (emphasis added).
[48] North American Electrical Reliability Corporation, Glossary of Terms Used in NERC Reliability Standards, at 20 (Sept. 10, 2013), available at http://www.nerc.com/files/glossary_of_terms.pdf (*"The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element."*).
[49] CPUC Revised Scoping Memo, Attachment A, at 2 (emphasis added).

required to include these megawatts in the next iteration of the transmission study (at least for Category C rather than Category D).

B. DG levels set by CPUC assumptions were not used for Category C

The Scoping Memo directed CAISO to apply customer-side PV to address second contingency resources:

> The location where customer-side PV will get built is difficult to predict, therefore the capacity amounts described here will be modeled as "Second Contingency" resources. The ISO shall determine the most effective busbars where customer-side PV should be located in order to address those contingencies. Once those locations are identified, the Commission can then direct customer-side generation programs, like the California Solar Initiative or other efforts, to target those locations.[50]

But CAISO's Opening Testimony instead states:[51]

> Q. Has the ISO considered the impact of the higher amount of demand response and additional small PV suggested in the Revised Scoping Ruling as being available under post second contingency conditions?
>
> A. Yes, *to a certain extent*. In a 2022 without SONGS scenario, the post second contingency includes a major combined cycle generating facility outage that occurs after an N-1-1 overlapping contingency of the Sunrise Powerlink and Southwest Powerlink lines. *According to NERC reliability standards, this is a Category D contingency* (extreme event resulting in two or more (multiple) elements removed or cascading out of service). Under these circumstances, the additional 997 MW of DR and approximately *796 MW (installed capacity) of customer-connected small PV identified in the Revised Scoping Ruling for post-second contingency could help to avoid a certain amount of load shedding*.

Rather than using these megawatts as directed by the Commission to reduce need, CAISO again is only considering them "to a certain extent" as resources that could reduce load shedding. This should be corrected to reduce the stated need by the megawatts specified in Attachment A.

Furthermore, the specific 796 MW of installed capacity is not the same as that listed in the Commission's Attachment A. Rather, Attachment A identified a total of 1093MW by 2022 (477MW for 2018 and 616MW for 2022). These numbers are then multiplied in Attachment A by .45 to .46 peak demand impact factor,[52] resulting in a total of 496 MW by 2022. It may be

[50] CPUC Revised Scoping Memo, Attachment A, at 10.
[51] CAISO Track 4 Testimony, at 29:9-21 (emphasis added).
[52] CPUC Revised Scoping Memo, Attachment A, at 9.

that the 796 MW listed by CAISO in the Opening Testimony is a typographical error, 496 MW is likely what CAISO meant.

C. Transmission and other losses were underestimated, resulting in underestimation of the total megawatt value of DG, EE, and DR gained through avoided transmission

CAISO's testimony recognized the value of freeing up transmission lines and avoiding transmission loss by using local Energy Efficiency (EE) and Demand Response (DR) instead of generation that has to be transmitted over a distance, although CAISO did not identify this factor for Distributed Generation (DG). Nevertheless, CAISO used a low percentage of loss – 4.76% – for the SCE and SDG&E service areas as compared to other sources. CAISO justified the low loss factor as "within the [4-5%] range which the CEC mentioned it would be for factoring in distribution losses for incremental EE."[53] Yet CAISO did not provide a specific citation for the CEC's loss range mentioned, nor has it provided one for SCE's 4.76% estimate.[54] CAISO used the same factor for avoided transmission losses due to DR.[55]

By comparison, in a report regarding DG benefits in California, the Interstate Renewable Energy Council (IREC) found a loss at peak of about 11% (transmission congestion greatly increases these losses):

> Similarly, an often-identified benefit of DG is its ability to avoid line losses. *Line losses occur as electrons flow through the transmission and distribution system to load and for central station power plants typically range from 5% to 11%, with the upper end of this range reached during times of peak loading when line losses are far higher.* Because DG is located on the site of load or very close to load, line losses can be virtually nonexistent to minimal.[56]

Losses can be measured as either a Loss Rate (a percentage of produced power lost), or "Loss Factor," (a number greater than one multiplied by the generation needed for the load to reflect

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[53] CAISO Track 4 Testimony, at 5:13-15 (emphasis added). "The CEC provided specific locations (i.e., bus-bar data) for modeling incremental EE. The following table provides a summary of the incremental EE, which was further scaled up by 4.76% to account for the estimated resulting distribution system loss reduction due to the incremental EE. The CEC noted that the incremental EE was provided at the customer's meter level. To account for distribution losses when these values are modeled at the sub-transmission voltage level (i.e., 66kV or 69kV), between 4 – 5% losses need to be added. The 4.76% was provided by SCE and to account for distribution losses. The same factor was also utilized for factoring the distribution losses in San Diego as SDG&E was unable to provide an estimate at the time. This factor, however, is within the range which the CEC mentioned it would be for factoring in distribution losses for incremental EE." *Id.* at 5:1-15.

[54] *Id.*

[55] CAISO Track 4 Testimony, at 6:21-22 ("*Similar to the EE modeling described above, the DR was scaled up by a factor 4.76% to account for distribution losses.*").

[56] Interstate Renewable Energy Council, 12,000 MW of Renewable Distributed Generation by 2020: Benefits, Costs, and Policy Implications, at 3 (July 2012), *available at* http://www.irecusa.org/wp-content/uploads/Final-12-GW-report-7.31.12.pdf (emphasis added).

the added power needed to make up for transmission losses).[57] Loss rates in percentage and loss factors can be converted to each other.[58]

A report by the CPUC consultant E3 found Peak Loss factors for SCE of 1.084 and SDG&E of 1.081 as measured on the whole path from the customer to the generator during the Summer Peak,[59] whereas CAISO applied its factor to some part of the subtransmission system, which may or may not include both line loss and substation equipment losses.[60] Converting the E3 numbers to loss rate percentages results in 7.7% for SCE and 7.5% for SDG&E, admittedly lower than the 11% found by IREC, but still appreciably higher than CAISO's 4.76%.[61] Applying E3's 7.7% for SCE and 7.5% for SDG&E to further scale-up numbers in CAISO's opening testimony Tables 2, 3, and 4, an additional 59MW of reduced need is added beyond the reduced need already found by CAISO, as follows:

Additional Energy Efficiency, based on CAISO Tables 2 and 3, adding higher losses:

	2018 Forecast/Modeled			2022 Forecast/Modeled			
	MW EE	Scaled up by 4.76%	Additional MW saved using higher loss factor of 7.7% SCE, 7.5% SDG&E	MW EE	Scaled up by 4.76%	Additional MW saved using higher loss factor of 7.7% SCE, 7.5% SDG&E	Total additional saved 2018 & 2022
L.A. Basin	427	448	13	751	787	22	35
San Diego	99	104	3	187	196	5	8
Total SONGS Study Area	526	552	15	938	983	28	**43**
Non-LA Basin (SCE)	129	134	4	222	232	7	**10**

[57] California Energy Commission, A Review of Transmission Losses in Planning Studies, at 11 (Aug. 2011), *available at* http://www.energy.ca.gov/2011publications/CEC-200-2011-009/CEC-200-2011-009.pdf ("*Loss factor* refers to a factor used to scale end use demand or retail sales to produce net energy for load. A loss factor is used to calculate how much more energy needs to be produced to account for losses and meet load." *Id.* at 12 ("The loss factor is similar to a *gross-up* factor that can be applied to a program to calculate avoided energy including losses. For example, a demand response program may displace 93 MWh of retail load. Accounting for losses of 7 percent, a gross-up factor of 1.075269 is multiplied by the program savings of 93 MWh to get the total avoided energy of 100 MWh including losses. The demand response program saves the utility from having to procure 100 MWh of resources to meet 93 MWh of load.").

[58] *Id.* (*"To convert from loss rate to loss factor: Loss factor = 1/(1-loss rate). . . . To convert from loss factor to loss rate: Losses (%) = 1 - 1/loss factor* .").

[59] Energy + Environmental Economics, California Solar Initiative Cost-Effectiveness Evaluation, Appendix B, at B-14 (Apr. 2011), *available at* http://ethree.com/documents/CSI/CSI%20Report_Complete_E3_Final.pdf.

[60] CAISO applied its 4.76% loss rate to the sub-transmission level.

[61] Losses (%) = 1 - (1/loss factor), for SCE, loss % = (1-1)/1.084 = 7.7%, and for SDG&E, loss% = (1-1)/1.081 = 7.5%.

Additional Demand Response,
based on CAISO Table 4, adding higher losses:

	MW DR	Additional MW saved using higher loss factor (7.7%)
Alamitos	6.75	0.2
Barre	27	0.8
DelAmo	25.3	0.7
Ellis	42.4	1.2
Johanna	16.2	0.5
Santiago	28.8	0.8
Viejo	9.9	0.3
VillaPark	24.8	0.7
Bernardo	8.4	0.2
Margarita	8.4	0.2
Total	197.95	**5.8**

When looking at the original numbers used by CAISO compared to CAISO'S scaled up numbers, CAISO's avoided losses add up to about 95MW[62] of reduced need for SCE and SDG&E, for 2018 and 2022 combined. Using the higher E3 numbers of 7.7% for SCE and 7.5% for SDG&E instead results in another 59 MW above CAISO's numbers; if the percent loss is increased to 11% during peak as used in the IREC report, then 126MW of reduced need would be achieved above CAISO's numbers; if the avoidance of transmission losses through Distributed Generation was accounted for as well, even more savings would be realized. A more realistic examination of line loss would reduce the amount of energy needed throughout the SONGS study area.

~~*D. CAISO left out the CPUC's assumption of 50 MW of Energy Storage*~~

~~CAISO contends that even the small amount of Energy Storage (50 MW) required as part of the LTPP Track I decision need not be included in its modeling:~~~~[63]~~

> ~~**Request No. 12.**~~
> ~~Please identify all energy storage resources, including the nameplate capacity and the qualifying capacity, that are included in CAISO's Track 4 modeling.~~

[62] (552-526) + (134-129) + (983-938) + (232-222) + (197.95-197.95/1.0476) = 95 MW.

~~[63] California Independent System Operator, Response of the California Independent System Operator Corporation to the First Set of Data Requests Related to Track 4 of the Division of Ratepayer Advocates; California Environmental Justice Alliance; Sierra Club, CA; and Clean Coalition, at 4 (July 12, 2013) (emphasis added).~~

~~**ISO RESPONSE TO No. 12.**~~

~~*Consistent with the local area studies presented in Track 1, the ISO will model the 40 MW of pumped storage (Lake Hodges) currently online in the San Diego area. The ISO does not have any information about the 50 MW of energy storage that SCE was directed to procure in the Track 1 decision and this assumption was not addressed in the Track 4 Revised Scoping Ruling.*~~

~~Lack of detail surrounding the 50 MW of energy storage is not an excuse to avoid accounting for it; after all, the Track I decision *required* the inclusion of that particular resource. Therefore, CAISO's need results should be corrected to include the 50 MW.~~

~~Furthermore, the impact of energy storage on the grid can be more than the megawatt value it provides. For instance, SCE has stated that "storage is two to three times more effective than conventional generation in meeting ramping requirements."[64] As such, the overall impact of the 50 MW should also be determined to the extent it is possible.~~

~~E.~~D. Existing resources could reduce need for new resources

CAISO modeling assumes gas plant retirements, including the Cabrillo 188 MW peakers in San Diego, but SDG&E owns this land and has chosen not to renew the lease. This issue was documented in the testimony of Bill Powers, P.E. for CEJA in the SDG&E PPTA[65] application process:[66]

> These turbines are capable of operational lifetime of up to 100,000 hours, with major overhauls every 15,000 to 25,000 hours.[67] At up to 877 hours per year of operation, these turbines have accrued only about 36,000 hours of operating time, only one-third of their operating lifetime potential.[68]
>
> The air quality regulations do not restrict the operation of the 188 MW of vintage gas turbine capacity. The only turbines that would be subject to any form of restriction are those that can not pass the annual air emissions source test. Even these restrictions would be exempted during peak demand system emergencies where the potential for brownouts

~~64 *See* Johannes Rittershausen & Mariko McDonagh, Moving Energy Storage From Concept to Reality: Southern California Edison's Approach to Evaluating Energy Storage, at 14 (May 20, 2011), *available at* http://www.edison.com/files/WhitePaper_SCEsApproachtoEvaluatingEnergyStorage.pdf.~~

65 A.11-05-023, Prepared Direct Testimony of Bill Powers on Behalf of California Environmental Justice Alliance, at 24-26 (May 18, 2012).

66 Docket No. 11-AFC-01, Bill Powers, Rebuttal Testimony of Bill Powers, P.E.: Pio Pico Energy Center, at 19 (July 6, 2012), *available at* http://www.energy.ca.gov/sitingcases/piopico/documents/others/2012-07-06_Rebuttal_Testimony_of_Bill_Powers_P_E_TN-66147.pdf.

67 Operation, Maintenance and Materials Issue, Gas Turbine Hot Section Life Assessment & Extension: Status & Issues, 3 OMMI 2, 2 (Aug. 2004), *available at* http://www.ommi.co.uk/pdf/articles/96.pdf.

68 877 hours/yr × 40 yr = 35,080 hours.

or blackouts exists.[69]

The primary reason that this 188 MW of peaking capacity will be retired in 2013 is that the turbines are located on SDG&E property and SDG&E is opting not to renew the lease with the third party owner of the turbines.[70]

SDG&E has an economic incentive to promote the construction of new third party gas turbine capacity in San Diego County. SDG&E has established a pattern of purchasing new natural gas-fired generation built in San Diego County by third party developers and passing the cost of this generation on to SDG&E ratepayers. As noted in SDG&E's May 19, 2011 testimony supporting the application for authorization to enter into power purchase agreements for 450 MW of new peaking gas turbine capacity, SDG&E acknowledges that it is in the process of purchasing the 50 MW CalPeak El Cajon peaking gas turbine.[71]

SDG&E has an economic incentive to promote third party gas plant construction in San Diego County by passing on the cost of purchase to ratepayers, with a guaranteed rate of return on infrastructure, transmission lines, and meters that it builds or purchases.[72] Thus the

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[69] San Diego Air Pollution Control District, Rule 69.3.1.: Stationary Gas Turbine Engines – Best Available Retrofit Control Technology (Feb. 24, 2010), *available at* http://www.sdapcd.org/rules/Reg4pdf/R69-3-1.pdf.

[70] A.06-08-010 Sunrise Powerlink, *SDG&E'S 7/8/07 Response to CPUC Division of Ratepayer Advocates Data Request No. 11*, July 8, 2007, p. 6. DRA request: Provide a copy of the current NRG-SDG&E lease provisions, and any related agreements, that call for the removal and site remediation of "173 MW of vintage peakers owned by NRG on SDG&E leased property" SDG&E response: Section 3.1 of the License Agreement, dated December 11, 1998, between SDG&E and Cabrillo Power II LLC provides that "unless sooner terminated as provided herein, the initial term of the License shall commence on the Closing Date and end on the earlier to occur of December 31, 2013 or the date on which Licensee decommissions or removes the Combustion Turbines from the Licensed Area and fails to replace them as permitted or required under any Must Run Agreement." At such termination or expiration of the License Agreement, Cabrillo Power II, LLC will no longer have any right to locate its combustion turbines on SDG&E land.

[71] SDG&E, CPUC Application A.11-05-023, *Prepared Direct Testimony of SDG&E in Support of Application for Authority to Enter into Purchase Power Agreements with Escondido Energy Center*, Pio Pico Energy Center and Quail Brush Power - Public Version, May 19, 2011, Appendix 9 - Van Horn Consulting, *Independent Evaluator's Report – Product 2: New Local Generation and SDG&E's June 9, 2009 RFO for Demand Response and Supply Resources*, May 18, 2011, p. 10. "CalPeak's El Cajon combustion turbine (CT) unit is located at SDG&E's El Cajon substation within SDG&E's Eastern O&M Center and is subject to a 10-year lease with SDG&E that expires on October 31, 2011.The land lease agreement grants SDG&E the option to purchase the plant at the end of the lease agreement. SDG&E has chosen to exercise this option, because the ECEF purchase meets the requirements of Product 5 and will be considerably less expensive than a PPA would be. SDG&E filed its Application (U 902 E) for the Authority to Acquire the CalPeak El Cajon Energy Facility (ECEF) with the CPUC on January 5, 2011."

[72] *Id.*, "SDG&E has an economic incentive to promote the construction of new third party gas turbine capacity in San Diego County. SDG&E has established a pattern of purchasing new natural gas-fired generation built in San Diego County by third party developers and passing the cost of this generation on to SDG&E ratepayers. As noted in SDG&E's May 19, 2011 testimony supporting the application for authorization to enter into power purchase agreements for 450 MW of new peaking gas turbine capacity, SDG&E acknowledges that is in the process of purchasing the 50 MW CalPeak El Cajon peaking gas turbine. Another example of this phenomenon is the purchase by SDG&E of the 555 MW Palomar Energy Project in Escondido, California. The project was built by SDG&E affiliate Sempra Generation at an installed cost of $348 million.55 Prior to completion of construction, the Commission authorized SDG&E to purchase the Palomar Energy Project from Sempra at a cost of $483 million.56 Purchasing natural gas-fired power plants constructed by third parties in San Diego County is a lucrative business

Commission's independent scrutiny of specific details around individual existing resource retirement is important to protect ratepayers, public health, and the environment from adding new, unnecessary, and significant new gas capacity when existing sources are already available as backups for outages that may never occur. Major new gas procurement is much more likely to be used more frequently than peakers and requires investment that could go toward clean renewable energy sources. Furthermore, such existing resources can provide a bridge in the unlikely case that new needs exist, while California is building its new clean renewable energy infrastructure. This makes more sense than adding new gas capacity with a long plant life.

IV. SCE and SDG&E left out preferred resources and other potential sources from modeling assumptions

SCE and SDG&E coordinated their studies[73] but began these before the Commission set assumptions to be used for Track 4, so some assumptions differed. CAISO evaluated the two regions of LA Basin and San Diego together, while SCE and SDG&E performed somewhat coordinated, but separate evaluations of each region, which creates difficulty when comparing assumptions. This section identifies and summarizes some of the differences and explains why SCE and SDG&E's study results still lead to a conclusion of no new generation need.

SCE and SDG&E testimony regarding independent modeling they each performed found no generation need in some cases and lower generation need than CAISO. SCE, in fact, concluded that consideration of possible transmission solutions along with strategic location of Preferred Resources could displace the need for *any* additional new LCR resources,[74] but SCE still requested generation procurement (up to 500 MW[75]), and SDG&E also requested 500-550 MW.[76] The major difference between SCE/SDG&E and CAISO modeling is the consideration of additional transmission improvements and load shedding by the utilities to reduce generation needs.

SCE also includes consideration of some targeted preferred resources in one of its cases. I agree with SCE and SDG&E that transmission and preferred resources reduce need, but the

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for SDG&E. The company receives a guaranteed rate-of-return on infrastructure, including transmission lines, power plants, and meters, that it builds or purchases." at pp. 20-21.

[73] SDG&E Jontry Track 4 Testimony, at 3:20-21; R.12-03-014, Robert B. Anderson, Prepared Track 4 Testimony of San Diego Gas & Electric Company, at 1:7-9 (Aug. 26, 2013) [hereinafter SDG&E Anderson Track 4 Testimony].

[74] SCE Track 4 Testimony, at 3:10-13.

[75] SCE Track 4 Testimony, at 3:14-16.

[76] SDG&E Anderson Track 4 Testimony at 12:3-6; SDG&E Jontry Track 4 Testimony, at 2:19-20.

utilities also left out resources that should have been considered to further reduce need, as discussed below. SCE also requests that its Preferred Resources proposal be backed up by contingent gas-fired generation, rather defeating the purpose of using preferred clean energy resources, and doing so without establishing need for new generation.[77]

SCE and SDG&E are asking for pre-approval to develop unspecified additional megawatts of generation through an "Energy Park" in the case of SDG&E, or "contingent generation" in the case of SCE, but these are not needed when the preferred resources, demand forecast change, and other considerations identified below are included.

The new CPUC Energy Storage targets which have now undergone detailed evaluation by the CPUC (also discussed later in this testimony) provide even more resources that should be adopted as assumptions in Track 4. The impact of energy storage on the grid can be more than the megawatt value it provides. For instance, SCE has stated that "storage is two to three times more effective than conventional generation in meeting ramping requirements."[78]

Furthermore, the Commission has recently identified underutilization of Demand Response (DR) Programs by SCE and SDG&E. On September 25, 2013, the Commission initiated a rulemaking proceeding intended to enhance the role of DR programs in meeting the state's clean energy goals.[79] In its order, the Commission identified the following problems with the utilities management of their DR programs:[80]

> The Staff Report indicates that, historically, SCE and SDG&E underutilized demand response programs and dispatched their power plants to meet peak demand far more frequently in comparison to demand response programs. The demand response programs were not utilized to their full Resource Adequacy capacity even during extremely hot weather conditions. Staff found that SCE also deployed a dispatch strategy for its residential air conditioning cycling program that was intended to minimize customer fatigue but resulted in the program delivering less demand response capacity.

This is extremely relevant because DR reduces peak demand and the Track 4 modeling needs are based on the 1-in-10 hottest year peak demand. The Commission's order highlights

[77] SCE Track 4 Testimony, at 50.

[78] *See* Johannes Rittershausen & Mariko McDonagh, Moving Energy Storage From Concept to Reality: Southern California Edison's Approach to Evaluating Energy Storage, at 14 (May 20, 2011), *available at* http://www.edison.com/files/WhitePaper_SCEsApproachtoEvaluatingEnergyStorage.pdf.

[79] California Public Utilities Commision, Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements, at 1 (Sept. 19, 2013), *available at* http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M077/K151/77151993.PDF [hereinafter CPUC Demand Response Order Instituting Rulemaking].

[80] CPUC Demand Response Order Instituting Rulemaking, at p. 7.

the importance of DR as a tool for peak reduction, and emphasizes the Commission's intention to expand DR programs.

SCE included load drop in its modeling but it requested another 500 MW of procurement to account for CAISO's more stringent standards since CAISO used additional conservative factors with no load drop. SDG&E stated it already had a load drop protection scheme approved for the worst contingency in the SONGS retirement evaluation (Sunrise & Southwest Powerlink N-1-1), but it did not apply it to its modeling.[81] These are further indications that demand management or load drop during the peak is not adequately utilized. The Commission has stated in its DR Rulemaking order its intention to correct this problem. The number of megawatts discussed in the ruling is substantial – 2,400 MW – (for *2012* which presumably has far lower DR potential than will be available in 2018-2022):

> None of the 2,400 MW from the Utilities' retail demand response programs participated in the CAISO markets in 2012 and the CAISO's ability to dispatch these demand response resources continues to be limited. . . .
>
> The Commission is hopeful that the new vision for demand response resources in this rulemaking and the increasing collaboration among the state agencies will help California overcome these challenges. [82]

The Commission's efforts will certainly lead to increased DR in 2018-2022 compared to today.

Regarding other resources, the State agencies are considering extending the retirement dates of certain OTC[83] facilities, which would also drastically change the results. The slides from the CEC/CPUC July 15 Joint Workshop showed that changing the retirement dates of Encina and the Kearney Peakers (aka the Cabrillo Peakers) is being considered.[84]

A. SCE

SCE stated in testimony that "[t]o the extent practical, SCE relied on the Revised Scoping Ruling and Memo of the Assigned Commissioner and Administrative Law Judge issued on May

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[81] SDG&E Jontry Track 4 Testimony, at 6:19-21 (*"For the analysis that examined the N-1-1 of ECO-Miguel and Ocotillo Express-Suncrest 500 kV lines as the limiting contingency, a load-shedding Special Protection Scheme (SPS) was not assumed to be allowed."*).
[82] CPUC Demand Response Order Instituting Rulemaking , at 14-15.
[83] Once-Through-Cooling.
[84] CAISO Presentation CEC/CPUC Joint SONGS Workshop, at 8-9.

21, 2013."[85] However, in response to a data request, SCE stated that it did not rely on the scoping assumptions and instead used different assumptions. Specifically, SCE was asked to describe any differences between the values SCE used in its Track 4 studies and the values from the May 21, 2013 Revised Scoping Ruling; SCE responded:

> <u>Response to Question 02</u>**:** SCE utilized a set of preferred resource assumptions which were different than the "Revised Scoping Ruling and Memo of the Assigned Commissioner and Administrative Law Judge issued on May 21, 2013" (2013 Revised Scoping Ruling). For all scenarios, the quantity of energy efficiency, DG and PV resources was developed by the CEC and are integrated into its load forecast. *Demand Response is not used in the load forecast.* In addition to the resources embedded in the load forecast, the Preferred Resources Scenario includes increased levels of energy efficiency, demand response, energy storage, and customer side PV. Table III-1 includes the quantity of each resource. These quantities are based on preliminary technical potential studies of demand response, energy efficiency, and customer PV included. Energy storage of 50 MW was chosen based on the LTPP Track 1 authorization. . . . [86]

Additional data responses from SCE explained that it did not include the customer-side PV, DR, or EE preferred resources assumed by the Commission's Scoping Ruling, but only used those that were already embedded in the load forecast (which have changed in the September 2013 forecast as discussed later in this testimony). SCE concluded the CPUC Assumptions were only for CAISO to use and not SCE:[87]

> <u>Question 03</u>: Specifically, did SCE include the *total customer-side PV* of 336 MW (117 NQC MW by 2018 plus 219 NQC MW by 2022) identified at p. 9 by the Commission's Attachment A in the Revised Scoping Ruling, anywhere in its assessment? Does SCE's conclusion of the need for 500MW of new generation procurement include any of this customer-side PV? How much?
>
> <u>Response to Question 03</u>: *No, the assumptions included in Attachment A only refer to CAISO studies* (see Attachment A page 2 line 1). For all scenarios, SCE's conclusion of the need for 500 MW of new generation procurement includes the customer-side PV to the extent that it is included in the CEC forecast. Those estimates were developed by the CEC. Additional preferred resources were included in the Preferred Resource Scenario (126 MW of customer-side PV)….
>
> <u>Question 04</u>: Please answer the same questions as in #3, but referring instead to the *Demand Response* numbers provided on p. 7 of the Revised Scoping Ruling Attachment A.

[85] SCE Track 4 Testimony, at 13 (emphasis added).
[86] SCE Response to CEJA, DRA, and Sierra Club, DATA REQUEST SET CEJA_DRA_Sierra Club-SCE-001, Question 2 (emphasis added).
[87] SCE Response to CEJA, DRA, and Sierra Club, DATA REQUEST SET CEJA_DRA_Sierra Club-SCE-001, Questions 3-5.

> Response to Question 04: *No, the assumptions included in Attachment A only refer to CAISO studies* (see Attachment A page 2 line 1). Demand Response resources, totaling 426 MW, are included in SCE's Preferred Resource scenario. SCE's conclusion of the need for 500 MW of new generation procurement does not include demand response….
>
> Question 05: Please answer the same questions as in #3, but referring instead to the *Energy Efficiency* numbers provided on p. 4 of the Revised Scoping Ruling Attachment A.
>
> Response to Question 05: *No, the assumptions included in Attachment A only refer to CAISO studies* (see Attachment A page 2 line 1). For all scenarios, SCE's conclusion of the need for 500 MW of new generation procurement includes energy efficiency to the extent that it is embedded in the CEC forecast. The estimates were developed by the CEC. Additional preferred resources were included in the Preferred Resource Scenario (50 MW of energy efficiency)….

SCE also confirms again that it used zero Preferred Resources beyond any included in the demand forecast, as shown in SCE's testimony in Table III-4 (listing Preferred Resources as "PR" in the table, with notes provided after the table),[88] except in the case of its Preferred Resources scenario. Rather than using these only in a "Preferred Resources" scenario (which presumably should include more preferred resources than baseline conditions), the Scoping Decision assumptions should have been considered in all the scenarios. SCE could then add additional Preferred Resources to a special scenario as it wishes, but currently the nomenclature is somewhat misleading (since its Preferred Resources contains less of these resources than the baseline Commission assumptions).

In SCE Testimony's Preferred Resources Scenario,[89] it included 50 MW of Energy Storage, 126 MW Rooftop Solar, and 452 MW of DR, totaling 628MW of these preferred resources. The CPUC assumptions on the other hand included 50 MW of Energy Storage, 390 MW of Rooftop Solar (171 NQC for 2018 + 219 NQC for 2022), and 794 MW of DR, totaling 1,234 MW, which is 606 MW more than SCE used in its Preferred Resources scenario and 1,234 MW more than any of the other scenarios.

Consequently, SCE modeling should be corrected to include the additional Preferred Resources (which includes EE, DR, and DG) set in Scoping Attachment A. This alone would offset any need for new generation. Therefore, SCE's proposal should be denied. With the much lower demand forecast discussed later in this testimony, the projected demand for the LA

[88] SCE Track 4 Testimony, at 31.
[89] SCE Track 4 Testimony, at 18, table III-1.

Basin is approximately 1,200 MW lower in the new September baseline 2013 CEC forecast for 2022, and approximately 2,650 MW lower in the new September Additional Achievable Energy Efficiency (AAEE) forecast for the LA Basin, further wiping out any potential need. Moreover, since substantially higher EE is achievable, the AAEE forecast can be considered merely a starting point for future EE mitigation. With the addition of EE to even more available resources with new Energy Storage targets and more focus on DR in upcoming Commission decisions, SCE will have more than enough preferred resources on hand to negate the need for new gas powered generation.

B. SDG&E

SDG&E found about 620 MW of need after application of transmission solutions[90] and then asked for a slightly lower amount of procurement (about 500-550 MW), based on the idea that it had not accounted for any DR. This means SDG&E assumed 70-120MW of DR, a small amount when compared to the 4-20% of peak reductions that, according to a FERC report, DR potential can provide.[91] SDG&E modeled its peak at 6,056,[92] so 4-20% of peak would be 242-1211 MW (which is 122-1141MW lower than FERC's potential). Compared even to the lower estimate of potential, SDG&E has under-underutilized DR. These higher levels of DR should be evaluated by the CPUC to be used in Track 4 since the new DR decision identifies the need to beef up DR programs. But the SDG&E numbers are still lower than those in the Scoping decision of earlier this year (which includes 203 MW for the second contingency, 2022).

Because SDG&E's modeling was conducted prior to the Commission's Proposed Energy Storage Decision, it did not include 165 MW of Energy Storage expected by 2020 as discussed later in this testimony (which should be adopted as an updated assumption for Track 4). Nor did it include the reduced CEC demand forecast also discussed later in this report (reduced by 108MW in the new baseline forecast for 2022, and reduced by 553MW in the new AAEE forecast for 2022).

Existing resources could also fill need by delaying retirement of 88 MW of local CHP and the 188 MW Cabrillo Peakers which SDG&E assumes will retire (276 MW together). A data request from POCF (Protect Our Community Foundation) to SDG&E asked about

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[90] SDG&E Anderson Track 4 Testimony at 11.
[91] Federal Energy Regulatory Commission, A National Assessment of Demand Response Potential, at xi-xii (June 2009) *available at* http://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf.
[92] SDG&E Anderson Track 4 Testimony at 7.

SDG&E's assumption that 88 MW of local CHP on a Navy site will retire, and SDG&E responded:[93]

> Robert Anderson's Opening Testimony states that "SDG&E assumes that 88 MW of local CHP units will be retired. [Their] resources are made up of three units that are located on military bases in San Diego. The Navy has indicated that it does not plan to renew these contracts when they expire in 2019." Please describe how the Navy has "indicated" that it does not plan to renew the CHP contracts. Please identify who at the Navy has provided SDG&E with this indication. Please provide correspondence or other official documents in SDG&E's possession that provide factual support for this assertion.
>
> **SDG&E Response:**
>
> SDG&E has requested, but the Navy has declined to provide consent for disclosure of the customer-specific information requested above. SDG&E notes that its assumption regarding availability of the Navy CHP resource was made for forecasting purposes and that the final decision will be made by the Navy at a later date. *Thus, as is the case with many of the forecast assumptions included in SDG&E's analysis, the ultimate outcome regarding availability of this CHP resource may differ from what was assumed by SDG&E.* Even if the Navy's CHP resource remains in operation, however, SDG&E's request for interim procurement authority of 500-550 MW would not be impacted.

SDG&E's response clarifies that the 88 MW of CHP may not retire. Nevertheless, SDG&E would still request the procurement whether or not this 88 MW is available.

In summary, the total of these resources including reduced demand forecast (lowered by 108 MW in the new baseline mid forecast to 553 MW lower with Additional Achievable EE for 2022), new energy storage targets of 165 MW, and existing resources of 276 MW that could delay retirement, provides options for resources between approximately 550 MW and 995 MW for SDG&E which offsets most or all of the need identified by SDG&E if transmission mitigation is included. Because EE is first in the Loading Order, cheaper than new generation, and faster to deploy, the load forecast with higher levels of EE at a minimum is more appropriate, but higher levels are achievable. (The new CEC September 2013 AAEE demand forecast discussed later in this report shows reduced need in the San Diego region for the period of 2018-2022, including 183 MW lower demand in 2018, and 359 MW lower demand in 2020. The new Energy Storage targets are also phased in every 2 years and are available before

[93] San Diego Gas & Electric, SDG&E Response to POCF Data Request of POFC, Question 9 (Sept. 17, 2013).

2018.[94]) This summary also does not include increased rooftop solar and other renewables which are rapidly expanding and should be deployed before any new gas generation.

Further, SDG&E's evaluation appears to be more consistent with CAISO's scenario that splits resources about 2/3 in the LA Basin and 1/3 in San Diego. However, CAISO also identified a better way to split resources: an 80/20 division between the LA Basin and San Diego. This reduces the SDG&E need to about 612 MW according to CAISO[95] (without the transmission fix that SDG&E identified, and without load drop). Given that SDG&E's transmission project reduced need by about 850 MW (1470 MW minus 620MW) according to its modeling, the transmission project could offset SDG&E's identified need if an 80/20 split was used, with some left over.

Even without the transmission mitigation (at CAISO's identified need of 620 MW for San Diego with the 80/20 split), the previously discussed additional DR, Energy Storage, and reduced demand could shrink the need by 550-950 MW in 2022, again offsetting most if not all of the need. Adding the transmission mitigation reduces the need even further, between about 1400 MW and 1800 MW (850 + (550 to 950 MW)), resulting in a surplus. Furthermore, since the LA Basin shows even more preferred resources and lowered demand, the resources can be allocated in other ways to utilize the increased LA Basin resources (e.g. 85% or more from LA and 15% or less from San Diego).

SDG&E did not model options for the LA Basin to cover a larger share. This 80/20 split makes much more sense than the (2/3)/(1/3) given the larger amount of available preferred resources in the LA Basin, the much greater drop in demand in the updated forecast for the LA Basin, the higher amount of other preferred resources left out of the modeling, higher targets for Energy Storage, and transmission mitigation in the LA Basin. Table 1 at the beginning of this testimony shows an overabundance of resources overall, even discounted by a third to be conservative, which more than covers any identified needs.

V. CAISO's reliability assumptions are extreme, going well beyond the CPUC Scoping Decision and NERC requirements

[94] The new September 2013 CEC baseline forecast for *2018* for San Diego (but not the LA Basin) shows a slight increase compared to the 2012 assumption, but this goes away by 2020 when the new forecasts show lower demand compared to the 2012 forecast.

[95] CAISO Track 4 Testimony at 26.

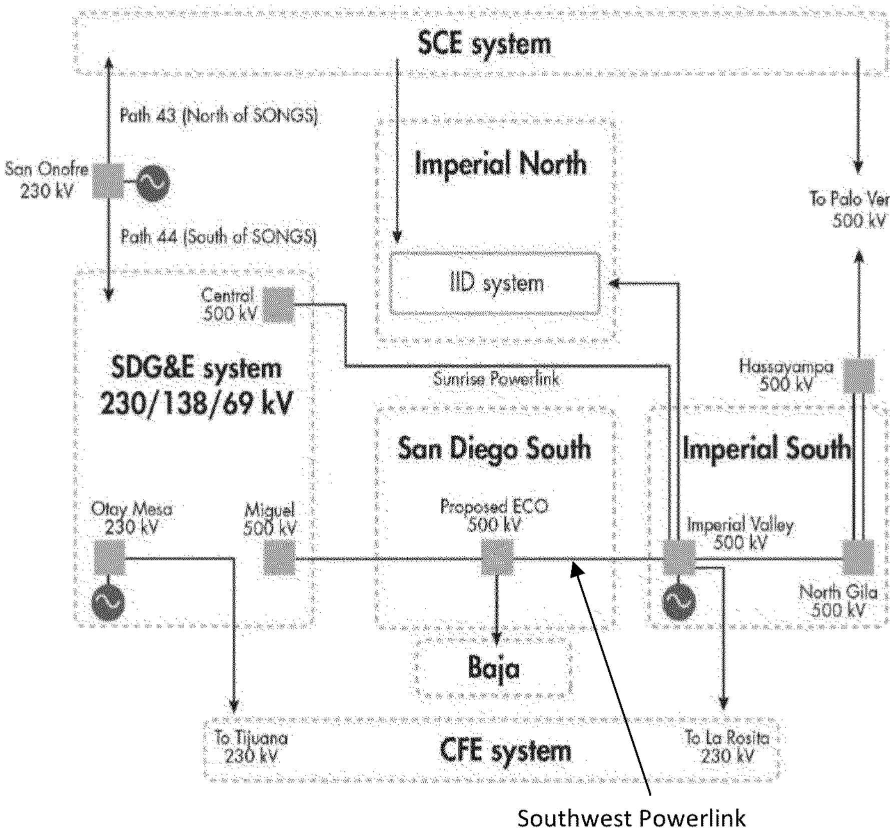
CAISO's Opening Testimony, data responses, and Transmission Plan provided reliability assumptions it used in its SONGS outage study. CAISO's SONGS-out analysis starts with the same very conservative assumptions it used for Track I of the CPUC's Long Term Procurement Proceeding, which go beyond WECC[96] and NERC requirements; but CAISO went beyond even that level in Track 4 by assuming outages on three major transmission lines on the hottest day in ten years, with a 2.5% added reserve margin, and with no load drop.

A. CAISO's study is based on three major transmission lines out of service, not two

In CAISO's study, it identified "the most critical N-1-1 contingency for the SONGS Study Area as the outage of the Sunrise Powerlink, system readjusted, followed by the outage of the Southwest Powerlink."[97] Resource needs identified in the study are based on this contingency. However, CAISO has explained that due to the outage of both these lines, a CFE line is also severed (from Otay Mesa to Tijuana for summer conditions).[98]

[96] Western Electrical Coordinating Council.
[97] CAISO Track 4 Testimony, at 6:11-13.
[98] California Independent System Operator, Response of the California Independent System Operator Corporation to the First Set of Data Requests Related to Track 4 of the Division of Ratepayer Advocates; California Environmental Justice Alliance; Sierra Club, CA; and Clean Coalition, Request No. 7 (July 12, 2013).

Illustration of SCE and SDG&E area[99] with Southwest Powerlink designation added



CAISO has stated that when the Sunrise Powerlink and Southwest Powerlink lines "are lost due to electrical short circuit conditions, they must be removed from service. When this occurs, the parallel CFE transmission line must be protected from overload, which requires that it be removed from service as well. When these lines are removed, no power can flow through them."[100] CAISO also confirmed in responses to data requests that the CFE line would be cut off as a result of an outage to the Southwest Powerlink and Sunrise Powerlink lines.[101]

[99] CAISO 2012-2013 Transmission Plan, at 281.

[100] A.11-05-023, CAISO Reply Brief, at 12; A.11-05-023, Hearing Transcript, at 624:11-24 (Sparks, CAISO). The same critical contingency was at issue in the A.11-05-023 proceeding.

[101] California Independent System Operator, Response of the California Independent System Operator Corporation to the First Set of Data Requests Related to Track 4 of the Division of Ratepayer Advocates; California Environmental Justice Alliance; Sierra Club, CA; and Clean Coalition, Request No. 7 (July 12, 2013) ("Q: In its track 4 analysis, does the line from the CFE to CAISO trip under certain conditions? What are those conditions? Has CAISO studied ways to mitigate the line from tripping? A: The line from Otay Mesa – Tijuana 230 kV [CFE] would be tripped under an overlapping N-1-1 contingency of Imperial Valley – Miguel 500kV [Southwest Powerlink] and Imperial Valley – Suncrest 500kV line [Sunrise Powerlink] to mitigate overloading concerns on CFE's 230kV system. Otay Mesa – Tijuana line is tripped for summer load conditions, and the Imperial Valley – La Rosita 230 kV line would be tripped for non-summer conditions.").

CAISO claims that the outage of the Sunrise Powerlink, system readjusted, followed by the outage of the Southwest Powerlink is a Category C outage.[102] A Category C contingency is an "[e]vent(s) resulting in the loss of two or more (multiple) [Bulk Electric System] elements."[103]

CAISO has identified this critical contingency as a C3 contingency[104] which is defined as the loss of a single element, manual system readjustment, followed by the loss of another element.[105] Under NERC Reliability Standards, CAISO is required to demonstrate that it can operate its transmission system under contingency conditions defined in Category C.[106]

However, the identified critical contingency appears more like a Category D contingency due to the additional loss of the CFE line. A Category D contingency is an extreme event resulting in two or more (multiple) elements removed or cascading out of service.[107] Unlike a Category C contingency, CAISO is not required to demonstrate operability during a Category D contingency.[108] Rather, it must only evaluate the risks and consequences of these extreme contingencies.[109] Therefore, the identified critical contingency appears to go beyond the operability requirements CAISO must demonstrate under NERC.

Even if CAISO appropriately considered the CFE line as tripped, transmission fixes are available to prevent the line from tripping. In A.11-05-023, CAISO identified potential solutions to prevent the CFE line from tripping.[110] There, CAISO identified a phase shifter and a series adapter as a potential solution to import more power from the CFE system into San Diego:

> We did look at a phase shifter on that Imperial Valley to CFE line…we found we needed a phase shifter and a series reactor because we were mostly looking at the loss of both lines, the Imperial Valley from Miguel and the Imperial Valley-Suncrest and the amount of phase shift you would need was very large angle. So to supplement the phase shifter, we put in a reactor.[111]

CASIO did not evaluate whether those solutions could be implemented in the A.11-05-023 proceeding. The phase shifter mitigation was examined in the context of CAISO's 2011/2012

[102] CAISO Track 4 Testimony, at 6:8-13.
[103] North American Electric Reliability Corporation, Reliability Standards for the Bulk Electric Systems of North America, [hereinafter NERC Reliability Standards] Standard TPL-003-2b, table1 (Sept. 10, 2013).
[104] CAISO Track 4 Opening Testimony, at 6:8-13.
[105] NERC Reliability Standards, Standard TPL-003-2b, at 5, t. 1.
[106] NERC Reliability Standards, Standard TPL-003-2b, B, R1, at 1.
[107] NERC Reliability Standards, Standard TPL-004-2a,at 5, t. 1.
[108] NERC Reliability Standards, Standard TPL-004-2a, B, R1, at 1.
[109] NERC Reliability Standards, Standard TPL-004-2a, B, R1, at 1.
[110] A.11-05-023, Hearing Transcript, at 542:6-544:4 (Sparks, CAISO).
[111] A.11-05-023, Hearing Transcript, at 542:10-542:23 (Sparks, CAISO).

transmission plan, which did not focus on lowering or eliminating any identified LCR need.[112] CEJA's expert in the SDG&E PPTA proceeding, Jaleh Firooz, agreed that phase shifters were a potential solution:

> One option that can be used to control flows on the CFE loop, is the installation of phase shifting transformers. The phase shifters could be installed on the U.S. side of the border and operated so as to limit post-contingency loop flow through the CFE system to levels that would not require CFE to operate its Special Protection Scheme. Assuming the costs of phase shifting transformers are in the $50 million range, assuming the CFE loop accommodates post-contingency imports into the San Diego area of about 500 MW, and assuming this import translates into a megawatt-for-megawatt reduction in San Diego area LCR, the option of installing phase shifting transformers may be far more economical and much less environmentally disruptive than SDG&E's proposed Product 2 generating resources.[113]

Even though the phase shifter mitigation could reduce the LCR need by approximately 500 MW, CAISO has not further analyzed whether this transmission mitigation could allow import over the CFE line and lower or eliminate the identified LCR need.[114] CAISO has stated that it will explore whether transmission improvements would prevent the CFE line from tripping in future transmission planning analysis:

> Q: Please explain what transmission improvements would prevent the CFE line from tripping in the event that the SWPL is out of service. Please explain the cost and nature of the transmission improvements.
>
> A: The ISO's Track 4 studies followed the Revised Scoping Ruling, which did not include analysis of the potential future transmission improvements referenced in the question. The ISO will explore the matter in future transmission planning analysis.[115]

CAISO has acknowledged that the "LCR needs for the San Diego-Imperial Valley area will decrease as additional transmission is constructed between the IID/CFE systems and Imperial Valley and more power is flowing in real-time from these control areas to the ISO control area."[116]

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[112] A.11-05-023, Hearing Transcript, at 543:10-544:4 (Sparks, CAISO).
[113] A.11-05-023, Exhibit 20, at 12 (Firooz Testimony).
[114] California Independent System Operator, Re: ISO Response to the Third Set of Data Requests Related to Track 4 of the Division of Ratepayer Advocates; California Environmental Justice Alliance; Sierra Club, CA; and Clean Coalition in Docket No. R.12-03-014, Requests No. 9 (Aug. 15, 2013).
[115] *Id.*
[116] CAISO LCT Analysis Addendum, at 27.

B. CAISO added a 2.5% reserve margin resulting in over 700 MW above LCR needs not required by NERC, further increasing the study's conservative nature

CAISO has stated that the LCR needs in the Track 4 study area increased as a result of the addition of a 2.5% reserve margin. Under WECC rules, the CAISO is required to add a 2.5% reserve margin under certain circumstances to account for enough reactive power resources to ensure voltage stability. However, CAISO is not required by NERC to apply this reserve margin. Whether the Commission agrees or not that this reserve is reasonable in this case, its presence certainly increases the conservative nature of the CAISO study, adding 700 MW in 2022 (or 670 MW in 2018) above LCR needs not required by NERC, *beyond* demand on the hottest day in ten years, after failure of three major transmission lines, without the additional available resources identified in this report. This underlines high confidence in a conclusion that there is no need for new generation to replace SONGS.

As discussed above, CAISO identified the most critical N-1-1 contingency for the SONGS study area as outage of Sunrise and Southwest powerlinks, and classified this as a Category C contingency. CAISO has since stated that this contingency would also trip another major transmission line (the CFE line discussed above), so this can instead be classified as Category D, but for the sake of this discussion, let us assume this is actually a Category C contingency. Under NERC rules, CAISO is required to demonstrate that it can operate its transmission system under contingency conditions defined in Category C,[117] although NERC does allow load drop to meet this contingency as discussed in the next section. CAISO did not use load drop or preferred resources discussed in this report to meet this contingency.

CAISO explained that it applied the 2.5% reserve in this case to meet the WECC Voltage Stability Criteria:[118]

> To perform these analyses described in the 2012/2013 Transmission Plan, the ISO followed the WECC Voltage Stability Criteria, specifically:
>
> For load areas, voltage stability is required for the area modeled at a minimum of 105% of the reference load level for system normal conditions (Category A), and for single contingencies (Category B). *For multiple contingencies (Category C), post-transient voltage stability required with the area modeled at a minimum of 102.5% of*

[117] NERC Reliability Standards, Standard TPL-003-2b.

[118] California Independent System Operator, Re: ISO Response to the First Set of Data Requests Related to Track 4 of the Division of Ratepayer Advocates; California Environmental Justice Alliance; Sierra Club, CA; and Clean Coalition in Docket No. R.12-03-014, Revisions to Questions 16(b) (July 31, 2013).

> *the reference load level.* For this criterion, the reference load level is the maximum established planned load limit for the area under study.
>
> Since the critical contingency for the SONGS Study Area is the Category C overlapping N-1-1 contingency of the Sunrise Powerlink and Southwest Powerlink 500kV lines, a 2.5% load incremental study case was developed for the voltage stability assessment.

Note that the second paragraph of the data response above is also contained in the WECC rules for certain conditions.[119] In response to another set of data requests, CAISO again confirmed that the results included an increase in load of 2.5% for the purpose of complying with WECC Voltage Stability Criteria assessment.[120] CAISO calculated that the addition of a this reserve margin increased LCR needs by 670 MW in 2018 and 704 MW in 2022 above the 1-in-10 worst year peak demand forecast.[121]

Southern California Edison (SCE) agreed with the conclusion that CAISO is not required to add a 2.5% reserve margin. In its Track 4 opening testimony, SCE asserted that CAISO used more stringent performance requirements than required by NERC rules.[122] As an example of where CAISO used more stringent performance requirements, SCE cited CAISO's use of a 2.5% reserve margin in its 2014 Local Capacity Technical (LCT) Analysis:[123]

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[119] Western Electricity Coordinating Council, System Performance TPL-001-WECC-RBP-2 Regional Business Practice, WR3, at 5 (Dec. 1, 2011), *available at* https://www.wecc.biz/Standards/Development/WECC%200100/Shared%20Documents/TPL-001-WECC-RBP-2.1.pdf.

[120] California Independent System Operator, Re: ISO Response to the First Set of Data Requests Related to Track 4 of Southern California Edison Company in Docket No. R.12-03-014, Request No. 6 (Aug. 21, 2013) (*"Q: On page 4, the CAISO indicates that the 2018 and 2022 1-in-10 peak load for the LA Basin and San Diego areas was based on the August 2012 California Energy Commission (CEC) mid-range economic and demographic assumptions. One performance requirement of the CAISO's Local Capacity Technical study is to increase the load by 5.0% for N-1 and 2.5% for N-2 contingencies to ensure positive reactive margin in the transmission system. Do the results presented in the testimony include an increase in load of 5.0% for N-1 and 2.5% for N-2 contingencies above the August 2012 1-in-10 CEC mid range load forecast? A: Yes, this need assumes the increase in loads, as indicated above, for compliance with the WECC Voltage Stability Criteria assessment."*).

[121] California Independent System Operator, Re: ISO Response to the Fourth Set of Data Requests Related to Track 4 of Division of Ratepayer Advocates; California Environmental Justice Alliance, Sierra Club, CA; and Clean Coalition in Docket No. R.12-03-014, Request No. 10 (Aug. 22, 2013) (*"The 2.5% margin in loads was factored on top of 1-in-10 peak demand forecast at the substation levels for the SONGS Study Area only to comply with the WECC Voltage Stability criteria. LA Basin loads and San Diego loads typically peak at the same time. All loads at individual substations modeled in the LA Basin and San Diego local cap**acity areas were raised uniformly by 2.5%. The additional loads to incorporate 2.5% margin for voltage stability analyses are 670 MW and 704 MW for years 2018 and 2022, respectively, for the SONGS Study Area."***).

[122] SCE Track 4 Testimony, at 26:5-13.

[123] California Independent Systems Operator, 2014 Local Capacity Technical Analysis: Final Report and Study Results, at 18 (Apr. 30, 2013), *available at* http://www.caiso.com/Documents/Final2014LocalCapacityTechnicalStudyReportApr30_2013.pdf.

> The following are two examples of more stringent performance requirements than NERC Reliability Standards used in the CAISO's LCT study to fully mitigate for the loss of OTC units:
>
> 1) The CAISO required the electric system to maintain positive reactive margin with the load forecast increased by 5% for Category A or B and 2.5% for Category C contingencies.[124]

SCE contended that CAISO's inclusion of a 2.5% reserve margin was to improve the reliability of the electric system and assure system performance levels above NERC standards.[125]

Finally, in the case that this is actually a Category D contingency, no 2.5% margin would be required.

C. Load drop is far more appropriate to satisfy need in extreme contingencies than building costly, polluting, and unneeded gas powered plants

SCE and SDG&E (whose customers are the ones affected) generally find in their testimony that load loss makes sense for more extreme events including Category C and Category D contingencies, and find that this is allowed by NERC standards (although the utilities are careful to note that CAISO is allowed to use more stringent standards). As SCE explains:

> NERC TPL Reliability Standards generally do not permit loss of demand, such as load shedding, for Categories A and B. However, if planned and controlled, NERC TPL Reliability Standards permit loss of demand for Category C. Category D contingencies are extreme events with no specific performance requirements other than an evaluation for risks and consequences.[126]

Utilizing controlled load drop should also make sense to the broad public since it would not be reasonable or cost-effective to over-build rarely needed resources; it is much more sensible to set up procedures for controlled loss of load for extreme and rare emergencies.

SDG&E already has a load-shedding scheme in place for the worst contingency that has been identified for the SONGS retirement modeling:

> SDG&E has a WECC-certified load shedding scheme in place to mitigate the N-1-1 of the Southwest Powerlink and the Sunrise Powerlink.[127]

Although CAISO is allowed to use load shedding for Category C contingencies,[128] CAISO has stated that it need not do so for the aforementioned N-1-1 contingency:[129]

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[124] SCE Track 4 Testimony, at 27:3-8.
[125] SCE Track 4 Testimony, at 27:16-18.
[126] SCE Track 4 Testimony, at 22.
[127] SDG&E Track 4 Testimony, at 7.

ISO RESPONSE TO No. 5.*As indicated in the left most column of Table 13, the need for 1222 MW is identified for the 2/3 / 1/3 split case. This need does not assume the addition of the potential Mesa Loop-In. This does not assume load shedding in SDG&E's service area for the overlapping N-1-1 (Category C) contingency, but does assume the load shedding for the simultaneous N-2 (Category D) contingency of the SWPL and Sunrise Powerlink lines."*

Voluntary load shedding is recognized as having major economic benefits for businesses:

> Load shedding is a means of reducing demand usage in a facility and will reduce energy usage by up to 20%. Many times demand charges exceed 50% of the total electric power bill. *This makes demand control a very attractive option to reduce operating costs.* [130]

Load shedding can also be involuntary but controlled, as a backup safety net for such unlikely events as those identified by CAISO for 2021. Load drop could be centrally or locally controlled.

CAISO has a tendency to favor other options over load shedding. CPUC staff made comments in February 2012 on the draft Transmission Plan specifically identifying load shedding as an option that CAISO could use instead of building large reliability projects (referring to large transmission projects that may not be necessary).[131] The staff noted CAISO's avoidance of load drop and found that although CAISO rules did not allow load drop for Category B events, they do allow it for Category C events, and clarified rules.[132]

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[128] For a discussion of category C events allowing load drop, and additional information about the conservative nature of CAISO's reliability assumptions *see*: R.12-03-014, Prepared Direct Testimony of Julia May on Behalf of the California Environmental Justice Alliance (CEJA), Before the Public Utilities Commission of the State of California, at 42:18-22 (June 25, 2012).

[129] California Independent System Operator, Response of the California Independent System Operator Corporation to the First Set of Data Requests Related to Track 4 of Southern California Edison Company, Request No. 5 (August 21, 2013) (*"Request No. 5. Referring to Table 13 on page 26, do you identify the need for 1222 MW in the LA Basin for the 2/3 / 1/3 split case? Does this need include any consideration of the addition of the Mesa Loop-In? Does this need assume that there is load shedding in SDG&E's service area?"*).

[130] Energy Controls Ltd., Load Shedding and Demand Control for Large Companies in California (June 30, 2011), *available at* http://www.egenergy.com/load-shedding-and-demand-control-for-large-companies-in-california (emphasis added).

[131] California Public Utilities Commission, Comments of the Staff of the California Public Utilities Commission on the January 31 2011 Draft of the 2011-2012 Transmission Plan, at 7-8 (Feb. 29, 2012), *available at* http://www.caiso.com/Documents/CPUC_Comments_Draft2011-2012_TransmissionPlan.pdf.

[132] California Independent System Operator, California ISO Planning Standards, at 6 (June 23, 2011) *available at* http://www.caiso.com/Documents/TransmissionPlanningStandards.pdf [hereinafter CAISO Planning Standards] ("No single contingency (TPL002 and ISO standard [G-1] [L-1]) should result in loss of more than 250 MW of load."). There is no stated ceiling on load shedding for double contingencies.

Staff also found that controlled interruption (load shedding) may sometimes be *necessary*.[133] For example, a NERC guideline describes Under Voltage Load Shedding (UVLS) as an appropriate safety net for severe contingencies.[134] CAISO has also identified load drop as a special protection for certain locations in Transmission Plans,[135] but doesn't identify this as a general tool for dealing with these severe contingencies.

As a backup safety net, load shedding is a much more appropriate tool for addressing highly unlikely contingencies than building major power plants to run for the next four decades, "just in case."

D. The worst in 10 year demand starting point is already conservative and not required by NERC; adding 3 lines down, 2.5% margin, and no load loss, is extreme

In addition to the conservative assumptions discussed above, it should be noted again that CAISO is already starting with a 1-in-10 hottest peak load as its primary reference point. While the Commission allowed CAISO's use of 1-in-10 in the LTPP Scoping assumptions,[136] it is worth remembering that this is a conservative starting point not required by FERC, NERC, or WECC standards for reliability planning.[137] Rather, CAISO's 1-in-10 formulation is based on its own interpretation of a particular phrase in both Category B and C of the NERC TPL Reliability Standards: "Projected Customer Demands"[138] NERC standards require:

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[133] . . . NERC reliability standards do not require avoidance of load shedding in the event of on N-2 (Category C) Bulk Electric System contingency, but rather state with regard to such contingencies that: *Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.*

[134] North American Electric Reliability Council, Guidelines for Developing an Under Voltage Load Shedding (UVLS) Evaluation Program, at 1 (Sept. 13, 2006), *available at* http://www.nerc.com/docs/pc/tis/UVLS_Guidelines_approved_by_PC.pdf ("For category C and D contingencies, the application of BPS UVLS programs should be considered as 'safety nets,' to avoid voltage collapse or voltage instability, and studied to ensure that they adequately perform that function … For NERC category C and D contingencies, application of locally applied UV relay schemes are acceptable to protect local load as described in the above introduction … The application of BPS UVLS programs also should be studied to address multiple unrelated outages (extreme events) and external contingencies.").

[135] *See* California Independent System Operator, 2011-2012 Transmission Plan, at 107, 124 (Mar. 23, 2012), *available at* http://www.caiso.com/Documents/Board-approvedISO2011-2012-TransmissionPlan.pdf; CAISO 2012-2013 Transmission Plan, at 200.

[136] CPUC Revised Scoping Memo, Attachment A, at 1.

[137] NERC Reliability Standards.

[138] NERC Reliability Standards, Standard TPL-002-2b, B, R1, at 1; NERC Reliability Standards, Standard TPL-003-2b, B, R1, at 1.

- For Category B (TPL-002-2b) that CAISO "demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply *projected customer demands*…under the contingency conditions as defined in Category B…"[139]
- For Category C (TPL-003-2b) that CAISO demonstrate through an assessment that "the network can be operated to supply *projected customer demands*..." under Category C conditions.[140]

NERC does not supply any definition for the term and FERC has not issued orders or decisions clarifying it. Taken in context, "projected customer demands" would appear to mean exactly what it says: a projection by the Planning Authority of customer demand during Category B and C contingencies. CAISO, however, deemed "projected customer demands" vague and in need of interpretation.[141] According to CAISO, "Projected Customer Demands" is defined as:

> The load level modeled in the studies can significantly impact the facility additions that the studies identify as necessary. For studies that address regional transmission facilities such as the design of major interties, a 1 in 5-year extreme weather load level should be assumed. *For studies that are addressing local load serving concerns, the studies should assume a 1 in 10-year extreme weather load level.*[[142]] The more stringent requirement for local areas is necessary because fewer options exist during actual operation to mitigate performance concerns. In addition, due to diversity in load, there is more certainty in a regional load forecast than in the local area load forecast. Having a more stringent standard for local areas will help minimize the potential for interruption of end-use customers.[143]

By defining "projected customer demands" as occurring during "1 in 10-year extreme weather," CAISO has significantly increased the potential load level used in the planning process. As stated above, NERC's TPL Reliability Standards aim to have Planning Authorities show that their transmission systems will work during Category B and C contingencies;[144]

[139] NERC Reliability Standards, Standard TPL-002-2b, B, R1, at 1.
[140] NERC Reliability Standards, Standard TPL-003-2b, B, R1, at 1.
[141] CAISO Planning Standards, at 14-15.
[142] CAISO does not provide any definitions to clarify the distinction between 'regional' and 'local.' However, according to FERC, a Regional Transmission Facility is "located solely within a single transmission planning region and [is] determined to be a more efficient or cost-effective solution to a regional transmission need[.]" FERC does not define "local load serving concerns," but does describe a Local Transmission Facility as "is a transmission facility located solely within a public utility transmission provider's retail distribution service territory or footprint that is not selected in the regional transmission plan for purposes of cost allocation." FERC Order No. 1000, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities; August 11, 2011; ¶ 63; 76 FR 49842-01.
[143] *Id.* at 15 (emphasis added).
[145] California Public Utilities Code § 345.

nowhere do NERC standards say they require an operable system under Category B and C conditions that also occur during low-likelihood, extreme weather conditions. While CAISO may be within its rights to create more stringent standards,[145] it is important to understand the use of a 1 in 10-year extreme weather load forecast is wholly a product of CAISO's conservative Transmission Planning Standards.

Even with these extreme assumptions, need is still zero since there are so many other resources not yet included in the study. However, as a general matter and for future evaluations, CAISO should not be allowed to apply such extreme assumptions. Although the Commission allowed the 1-in-10 hottest year assumption in this case, this assumption should not be compounded by modeling need after three lines are lost, with an added 2.5% reserve margin, and no load loss. This would result in unreasonably skewed modeling favoring unnecessary new generation in future evaluations. If the generation is filled with new gas resources, the results become even more costly, and harmful given the associated greenhouse gas and smog precursor emissions, thereby undermining California's ability to meet crucial long term greenhouse gas reduction goals, especially the 80% reduction goal for 2050.[146] If any new generation is considered, it should be filled with cleaner preferred resources.

E. *The cost of rebuilding through natural gas in economic, environmental, and health terms, is unimaginably high*

Authorizing procurement of new unnecessary natural gas resources sends California backward in its commitment to cut greenhouse gases (GHGs) and avoid catastrophic climate change. An approach to meet California 2050 and other goals requires accelerating usage of clean resources and decarbonization of our electricity sources.[147] This is particularly apropos since the Track 4 Proceeding aims to replace a non-carbon electricity source: SONGS. Replacing it with fossil fueled sources would be a step in the wrong direction.

Scientific consensus warns us sternly and repeatedly that GHG reductions are needed within a few years or we face catastrophe. Recent reports find that emissions are not going down and the potential impacts of continuing on our current path are disastrous:

[145] California Public Utilities Code § 345.
[146] *See* J. Williams, et. al, The Technology Path to Deep Greenhouse Gas Emissions Cuts By 2050: The Pivotal Role of Electricity, 355 Science 6064 (Jan. 2012).
[147] *Id.* at 53.

- The New Scientist reported that "[o]ur emissions are not slowing, but instead are climbing rapidly: If we stopped pumping more CO_2 into the atmosphere now, we'd have a very good chance of avoiding a big hike in temperature. But there is no sign of that happening. Annual emissions fell only slightly after 2008 - the biggest financial crisis since the Great Depression - and are now climbing more rapidly than ever. So far they are near the top of the IPCC's worst-case emissions scenario. 'Our emissions are not slowing,' says Paul Valdes of the University of Bristol, UK. 'That's the most scary aspect of our future.'"[148]

- A World Bank report found we need serious policy changes to avoid a disastrous 4°C rise in temperatures: "It is my hope that this report shocks us into action. . . . This report spells out what the world would be like if it warmed by 4 degrees Celsius, which is what scientists are nearly unanimously predicting by the end of the century, without serious policy changes. . . . The 4°C scenarios are devastating . . . If [current mitigation commitments] are not met, a warming of 4°C could occur as early as the 2060s."[149]

- Although it is extremely difficult to identify the cause of *individual* weather events, NOAA (the National Oceanic and Atmospheric Administration) reported that "New analyses find evidence of human-caused climate change in half of the 12 extreme weather and climate events analyzed from 2012"[150] based on a report by the American Meteorological Society.

- California's Office of Environmental Health Hazard Assessments (OEHHA) identified in a new report current indicators of climate change in California, including the following examples (among many others)***:***[151]

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148 New Scientist, Climate Downgrade: Human Emissions by Michael LePage, Nov. 14, 2012, *available at* http://www.newscientist.com/article/mg21628912.000-climate-downgrade-human-emissions.html.

149 Turn Down the Heat, Why a 4°C Warmer World Must Be Avoided, A Report for the World Bank by the Potsdam Institute for Climate Impact Research and Climate Analytics, World Bank, November 2012, http://climatechange.worldbank.org/sites/default/files/Turn_Down_the_heat_Why_a_4_degree_centrigrade_warmer_world_must_be_avoided.pdf .

150 NOAA, New analyses find evidence of human-caused climate change in half of the 12 extreme weather and climate events analyzed from 2012, September 5, 2013, *available at* http://www.noaanews.noaa.gov/stories2013/20130905-extremeweatherandclimateevents.html, highlighting a report of the American Meteorological Society, Peterson, T. C., M. P. Hoerling, P. A. Stott and S. Herring, Eds., 2013: Explaining Extreme Events of 2012 from a Climate Perspective. *Bull. Amer. Meteor. Soc.*, **94** (9), S1–S74. The Abstract finds: *" Attribution of extreme events is a challenging science and one that is currently undergoing considerable evolution. In this paper are 19 analyses by 18 different research groups, often using quite different methodologies, of 12 extreme events that occurred in 2012. In addition to investigating the causes of these extreme events, the multiple analyses of four of the events, the high temperatures in the United States, the record low levels of Arctic sea ice, and the heavy rain in northern Europe and eastern Australia, provide an opportunity to compare and contrast the strengths and weaknesses of the various methodologies. The differences also provide insights into the structural uncertainty of event attribution, that is, the uncertainty that arises directly from the differences in analysis methodology. In these cases, there was considerable agreement between the different assessments of the same event. However, different events had very different causes. Approximately half the analyses found some evidence that anthropogenically caused climate change was a contributing factor to the extreme event examined, though the effects of natural fluctuations of weather and climate on the evolution of many of the extreme events played key roles as well."* http://www.ametsoc.org/2012extremeeventsclimate.pdf.

151 Indicators of Climate Change in California August 2013, http://oehha.ca.gov/multimedia/epic/pdf/ClimateChangeIndicatorsReport2013.pdf.

- Heat-related mortality and morbidity: Although largely preventable, heat-related illnesses and deaths in humans are expected to result from continued warming and more frequent and intense heat waves. The July 2006 heat wave, unprecedented in its magnitude and geographic extent, resulted in 140 heat-related deaths in California. (at p. v)
- Large wildfires: Since 1950, annual acreage burned in wildfires statewide has been increasing in California. The three largest fire years occurred in the last ten years. A large spike in annual average acreage of conifer and shrubland burned statewide occurred from 2000-2008. In the western United States, large wildfires have become more frequent, increasing in tandem with rising spring and summer temperatures. (at p. v)
- Annual Sierra Nevada snowmelt runoff: Spring snowmelt from the Sierra Nevada to the Sacramento River has declined over the past century. (at p. iv)

- A report from the Barr Foundation[152] identified inequities in impacts of climate change, finding there "is a climate gap. The health consequences of climate change will harm all Americans—but the poor and people of color will be hit the worst (at p. 7).... The climate gap means that communities of color and the poor will breathe even dirtier air. For example, five of the smoggiest cities in California also have the highest densities of people of color and low-income residents. These communities are projected to suffer from the largest increase in smog associated with climate change." (at p. 5).
- An important new study published in Nature (Sept. 22, 2013)[153] related the "[c]o-benefits of mitigating global greenhouse gas emissions for future air quality and human health" and showed avoided mortality and avoided costs that were higher than previously shown. It found that "[a]ir quality and health co-benefits, especially as they are mainly local and near-term, provide strong additional motivation for transitioning to a low-carbon future."
- A World Meteorological Organization summary identified examples of major global

[152] The Clmate Gap – Inequalities in How Climate Change Hurts Americans & How to Close the Gap, Rachel Morello-Frosch, Ph.D., MPH, Manuel Pastor, Ph.D., James Sadd, Ph.D., Seth B. Shonkoff, MPH, *available at*: http://www.barrfoundation.org/files/The_Climate_Gap.pdf.

[153] *"Actions to reduce greenhouse gas (GHG) emissions often reduce co-emitted air pollutants, bringing co-benefits for air quality and human health. Past studies typically evaluated near-term and local co-benefits, neglecting the long-range transport of air pollutants, long-term demographic changes, and the influence of climate change on air quality. Here we* ***simulate the co-benefits of global GHG reductions on air quality and human health using a global atmospheric model and consistent future scenarios, via two mechanisms: reducing co-emitted air pollutants, and slowing climate change and its effect on air quality.*** *We use new relationships between chronic mortality and exposure to fine particulate matter and ozone, global modelling methods and new future scenarios. Relative to a reference scenario, global GHG mitigation avoids 0.5±0.2, 1.3±0.5 and 2.2±0.8 million premature deaths in 2030, 2050 and 2100.* ***Global average marginal co-benefits of avoided mortality are US$50–380 per tonne of CO_2, which exceed previous estimates, exceed marginal abatement costs in 2030 and 2050, and are within the low range of costs in 2100.*** *East Asian co-benefits are 10–70 times the marginal cost in 2030. Air quality and health co-benefits, especially as they are mainly local and near-term, provide strong additional motivation for transitioning to a low-carbon future."* J. Jason West, Steven J. Smith, Raquel A. Silva, Vaishali Naik, Yuqiang Zhang, Zachariah Adelman, Meridith M. Fry, Susan Anenberg, Larry W. Horowitz & Jean-Francois Lamarque Nature Climate Change 3, 885–889 (2013), Published online: 22 September 2013.

climate change happening now:[154] "The Arctic is changing rapidly. . . .The Arctic summer of 2012 witnessed even more dramatic changes, with a record low Northern Hemisphere snow extent in June, a record low sea-ice extent in September, record high permafrost temperatures in northernmost Alaska, and the longest duration of melting on the Greenland ice sheet ever observed in modern times, with a rare, nearly ice sheet-wide surface melt in July. . . . Sea levels are changing globally. . . . As warming penetrates deeper into the oceans and ice continues to melt, sea levels will continue to rise long after atmospheric temperatures have leveled off."

A heavy reliance on gas-powered generation would simply continue business-as-usual and exacerbate the already existing global climate problems.

The Commission must work against this rising tide by making sure it follows the Loading Order and aims to meet California's goal of 80% reduction of GHGs by 2050. The decision related to SONGS will have significant repercussions on California's ability to meet these GHG goals. The addition of new gas-powered generation – either the approximate 1000 MW proposed by SCE and SDG&E, or the 2500 MW found as need by CAISO but not yet proposed for approval – would emit millions of tons of GHGs per year,[155] taking us a step backward in reaching California GHG goals.

Several well-respected scientists recently published a roadmap that identifies where GHG reductions need to occur to meet the State's 2050 goal.[156] Two of the primary measures necessary to meet the 2050 goal are directly related to energy usage. Specifically, the study found that "energy efficiency had to improve by at least 1.3% per year over 40 years" and that "electricity supply had to be nearly decarbonized, with 2050 emissions intensity less than 0.025 kg CO2e/kWh."[157]

To further reduce GHG emissions from 1990 levels in 2020 to 80 percent below 1990 levels in 2050, significant action is necessary. Even though reductions may occur, it is also

[154] World Meteorological Organization, A Summary of Current Climate Change Findings and Figures, March 2013, pages 5-6, *available at*: http://www.wmo.int/pages/mediacentre/factsheet/documents/ClimateChangeInfoSheet2013-03final.pdf.

[155] For example, the new Oakley approved 625 MW plant would emit almost 2 million metric tonnes/yr of CO2e, (*Oakley Generating Station Commission Decision*, CEC-800-2011-002-CMF, May, 2011) so 1000 MW of new gas would emit about 3 million tonnes/year, and 2500 MW of new gas about 7.5 million. This does not count the GHG emissions from fracking or conventional drilling for the natural gas used in generation, which can double or triple GHG emissions. (Information on emissions from natural gas production for both fracked and conventional gas production drilled were provided by a Cornell study which found about 22 to 45 g C /MJ of shale gas produced, over a 20-year timeframe, from chart, p. 1, (R.W. Howarth, D. R. Atkinson, Assessment of the Greenhouse Gas Footprint of Natural Gas from Shale Formations Obtained by High-Volume, Slick-Water Hydraulic Fracturing, Cornell University, (*Rev. April 11, 2011*), http://www.eeb.cornell.edu/howarth/Marcellus.html)).

[156] *See* J. Williams, et. al, The Technology Path to Deep Greenhouse Gas Emissions Cuts By 2050: The Pivotal Role of Electricity, 355 Science 6064, at 53-59 (Jan. 2012).

[157] *Id.* at 53.

crucial to remember CO_2 emissions continue to accumulate in the atmosphere every year, constantly increasing the atmospheric burden, and worsening impacts. CO_2 has a variable, but very long atmospheric lifetime, and a portion lasts for millennia.[158] Consequently, it is essential that California not replace SONGS with GHG polluting sources.

VI. Summer Peak forecast has gone down considerably and offsets substantial need

CAISO's Opening Testimony states that it uses the mid-range 1-in-10 forecast from August 2012 as follows[159] (which is also identified as the most recent in the CPUC Scoping):

> The ISO modeled the 2018 and 2022 1-in-10 peak load for the LA Basin and San Diego local capacity areas based on the CEC's mid-range economic and demographic assumptions. The most recently adopted forecasts are contained in the 2012 Integrated Energy Policy Report, August 2012 revision, form 1.5d. The following provides summary of the CEC's 1-in-10 heat wave load forecast for the LA Basin and San Diego local capacity areas.

However, this forecast has since been revised significantly downward in September 2013 by the California Energy Commission (CEC), and it makes sense for the assumptions to be modified by the CPUC for Track 4 to reflect these updates.

The CEC's most recent baseline forecast (again using the mid-case for 1-in-10 year peak) reduced the total demand for the LA Basin and San Diego regions by 1,208 MW for 2018, and 1,321 MW for 2022, compared to the 2012 forecast used by CAISO and SCE as further detailed below. In addition, the CEC provided another updated forecast – the AAEE forecast – which reduced the need by 2,234 MW for 2018, and 3,203 MW for 2022 (again the mid-range forecast 1-in-10 peak) compared to the 2012 forecast used by CAISO. EE reductions beyond those in the AAEE forecast are achievable, but CAISO and the utilities should at a minimum include these levels.

Table 2 – Difference between CAISO assumption & updated forecasts
(The first set compares the new September 2013 baseline forecast to CAISO'S 2012 assumption; the second compares the new September 2013 AAEE update to CAISO's 2012)

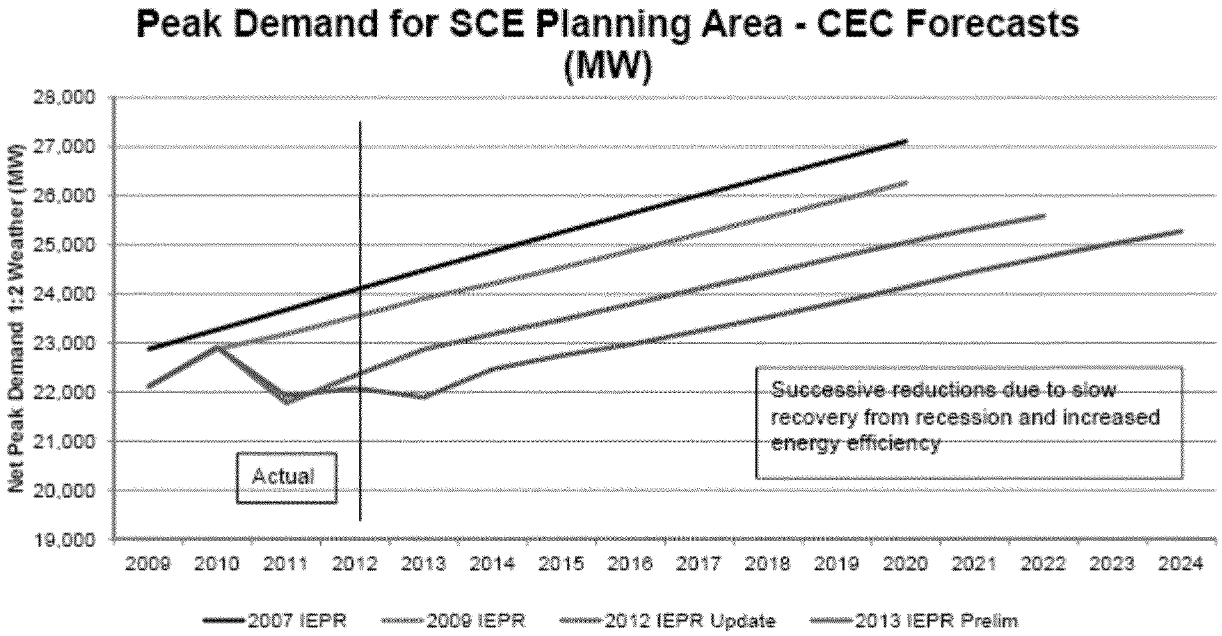
[158] D. Archer, University of Chicago, Carbon is Forever, Nature Reports, Climate Change, Vol. 2 (Dec. 2008) *available at* www.nature.com/reports/climatechange ("The lifetime of fossil fuel CO2 in the atmosphere is a few centuries, plus 25% that lasts essentially forever.").
[159] CAISO Track 4 Testimony, at 4:16-21.

CAISO used Aug. 2012 CEC forecast[160]			Updated CEC Sept 2013 baseline[161]		Difference (MW)	
	2018	**2022**	**2018**	**2022**	**2018**	**2022**
L.A. Basin	21,870	22,917	20,609	21,704	1,261	1,213
San Diego	5,652	6,056	5,705	5,948	-53	108
Total	27,522	28,973	26,314	27,652	**1,208**	**1,321**
			Updated CEC Sept 2013 AAEE forecast[162]		**Difference (MW)**	
			2018	**2022**	**2018**	**2022**
			19,819	20,267	2,051	2,650
			5,469	5,503	183	553
			27,306	27,792	**2,234**	**3,203**

The downward trend seen in the 2013 CEC forecast is attributable in large part to two adjustments from the 2011 forecast: a change in the price elasticity of electricity demand and the adoption of two new efficiency regulations.[163] A significant reduction in demand resulted from the implementation of new Title 20 Battery Charger Standards and an update to Title 24 Building Standards,[164] neither of which was included in the 2011 forecast.[165]

CEC slides from the July 15, 2013 SONGS-retirement workshop show continued lowering of peak demand (entitled EVOLVING DEMAND):[166]

[160] The spreadsheets used by CAISO can be found at: http://www.energy.ca.gov/2012_energypolicy/documents/demand-forecast/Mid_Case_LSE_and_Balancing_Authority_Forecast.xls.
[161] Mid Case LSE and Balancing Authority-AAEE adjustment.xlsx excel spreadsheet, revised 9/20/2013, Form 1.5d, available at: http://www.energy.ca.gov/2013_energypolicy/documents/2013-10-01_workshop/spreadsheets/
[162] Mid Case LSE and Balancing Authority-AAEE adjustment.xlsx excel spreadsheet, revised 9/20/2013, Form 1.5d, available at: http://www.energy.ca.gov/2013_energypolicy/documents/2013-10-01_workshop/spreadsheets/
[163] California Energy Commission, DRAFT STAFF REPORT, California Energy Demand 2014-2024 Preliminary Forecast, Volume 1: Statewide Electricity Demand, End-User Natural Gas Demand, and Energy Efficiency, May 2013; page 1.
[164] *Id.* at 68.
[165] California Energy Commission, COMMISSION FINAL REPORT, California Energy Demand 2012-2022 Final Forecast, Volume 1: Statewide Electricity Demand, End-User Natural Gas Demand, and Energy Efficiency, June 2012; page 69, Table 3-3.
[166] CAISO Presentation CEC/CPUC Joint SONGS Workshop, at 4.



While the Commission did list the 2012 forecast as the most recent at the time in the Revised Scoping Attachment A assumptions, since an update now shows substantially reduced needs, it would be prudent to take this reduction in the demand forecast into account to offset any finding of need. CAISO has already stated that it "wants to consider incorporating the 2013 IEPR demand forecast which is anticipated to be completed and adoped by the CEC Commission by the end of this year."[167] The CPUC should follow CAISO's lead and rely on the CEC's most recent demand forecast in this proceeding. The CPUC has previously endorsed using the most recent CEC forecast, even if it is a draft. In particular, the CPUC decided to use the 1-in-2 summer forecast in the 2007 draft CEC base case, which was the most recent then available, even though that base case had not previously been part of the proceeding.[168] The CPUC explained its choice of the most recent CEC forecast available at that time, stating that its policy required an updated need analysis with the most recent information:

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

[167] CAISO Track 4 Testimony, at 30.
[168] *See* D.07-12-052 at 29.

> concern, however, we believe that the draft forecast provides a better 'snapshot' of the current needs of the system.[169]

The CPUC further found that using the then-new draft CEC forecast was reasonable in the LTPP because "CEC's IEPR[170] process is the proper forum to litigate and contest issues related to each IOU's[171] demand forecast."[172] Similarly, in this proceeding, the CEC's most recent forecast provides a better, more recent snapshot of the system.

In addition, the CPUC has previously asserted that it expects future utility procurement decisions to rely on the best available information, especially considering the potential environmental impacts that can result from procurement decisions:

> Informed decision-making depends on robust analysis. While we recognize that electric resource planning is inherently uncertain, perhaps now more than ever before, we expect the IOUs to integrate the best, most recent planning methodologies and analytical techniques. In subsequent iterations of the long-term procurement process, the IOUs will be expected in their resources planning to meet and exceed the high standards Californians expect as pacemakers on energy and environmental issues.[173]

Thus, the CPUC required utilities to use the "best, most recent planning methodologies," which includes a more recent forecast giving a "better 'snapshot' of the current needs of the system." The Commission should do the same here and use the September 2013 AAEE data from the CEC's 2013 Preliminary Demand Forecast and should consider additional EE as well.

[169] *See* D.07-12-052 at 29-30.
[170] IEPR – The Integrated Energy Policy Report of the California Energy Commission.
[171] IOU – Investor Owned Utility.
[172] *See* D.07-12-052 at 29.
[173] *See* D.07-12-052 at 6.

VII. Any unlikely remaining need should be met first by added preferred resources, especially the new Energy Storage targets

The missing resources listed in Table 1 above are far higher than the need for generation identified in the CAISO Track 4 study, even given the very conservative starting point. In the event that there is any consideration of added generation due to SONGS retirement, such need can be met by additional preferred resources. The Revised Scoping Decision Attachment A provided the assumptions for preferred resources that should go into the modeling and to be used for N-1-1 contingencies, but neither CAISO nor the CPUC has identified whether any remaining need must necessarily be met by new gas resources. To the contrary, given the Loading Order and environmental and public health concerns, in the event of any remaining need, preferred resources should be considered first, before new gas. The following identifies additional resources beyond the Attachment A assumptions likely to be available in the next decade.

A. Energy Storage identified in the dedicated Commission proceeding should be added

In addition to the approved 50 MW of storage left out of the modeling, substantial additional Energy Storage is expected to be available in both 2018 and 2022 as set in the recent proposed decision of Commissioner Peterman in Energy Storage proceeding R.10-12-007. Regardless of whether additional new generation is considered by the Commission, Track 4 assumptions should be modified to include at least these well-thought out targets from the Energy Storage proceeding which provide far-ranging benefits to California.

The proposed Ruling of Commissioner Peterman includes a total of 580 MW of storage procurement targets for the SCE area and 165 MW for the SDG&E area by 2020.[174] The ruling phases in these levels over time, with targets increasing every two years beginning in 2014, including 160 MW for SCE and 45 MW for SDG&E in 2018. The new Energy Storage targets should be used to fill any need before considering new gas generation.

The SONGS study area, however, does not include the entire SCE service area: the LA Basin portion comprises about 77%[175] of this. Seventy seven percent of SCE's 580 MW target

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[174] R.10-12-007, Decisions Adopting Energy Storage Procurement Framework and Design Program, Assigned Commissioner Peterman (September 3, 2013), at p. 15, *available at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M076/K387/76387254.PDF.*

[175] Using the same ratio as the ratio of LA Basin demand to the SCE demand, in both the Sept. 2013 baseline or the Sept. 2013 AAEE mid demand forecast of the SCE, at 2020, databases available at http://www.energy.ca.gov/2013_energypolicy/documents/2013-10-01_workshop/spreadsheets/

for 2020 amounts to 447 MW in the LA Basin; add that to SDG&E's 165 MW and the total Energy Storage target for the SONGS study area comes to 612 MW for 2020.

The total target for SCE, SDG&E, and Pacific Gas & Electric is 1,325 MW by 2020. This ruling provides a major breakthrough in removing existing barriers that disfavor storage procurement while setting a specific framework to reach the targets. Even so, this is still a relatively modest target when compared to Governor Brown's Clean Energy Jobs Plan target of 3,000 MW by 2020.

The ruling floated earlier this summer highlighted the transformative qualities of Energy Storage:

> 2. Guiding Principles and Policy
> Energy storage has the potential to transform how the California electric system is conceived, designed, and operated. In so doing, energy storage has the potential to offer services needed as California seeks to maximize the value of its generation and transmission investments: optimizing the grid to avoid or defer investments in new fossil fuel-powered plants, integrating renewable power, and minimizing greenhouse gas emissions.[176]

The earlier floated decision also noted that while Track 4 of the LTPP proceeding was a separate, parallel process not directly connected to the Energy Storage proceeding, the ruling expected that these proceedings would be increasingly tied together in the future.[177]

Additionally, Administrative Law Judge Gamson recently asked for comments concerning whether the Energy Storage ruling targets should be taken into account to provide resources in Track 4. Given the specific evaluations and framework in the Energy Storage proceeding, which provide a measured, specific, step-by-step procurement framework that is expanded every two years; and given the Governor's target, it seems exceedingly reasonable that

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[176] R.10-12-007, Assigned Commissioner's Ruling Proposing Storage Procurement Targets and Mechanisms (June 10, 2013), *available at* http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M065/K706/65706057.PDF.

[177] R.10-12-007, Assigned Commissioner's Ruling Proposing Storage Procurement Targets and Mechanisms, at 8 (June 10, 2013), *available at* http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M065/K706/65706057.PDF. ("Finally, I note that the timing of this proposal predates two important procurement and planning efforts within the Commission's Resource Adequacy (RA) proceeding and LTPP proceedings. Parties to the RA proceeding have been evaluating a new flexible RA capacity product. Within the LTPP proceeding, the Commission is presently conducting an evaluation of system need, which is anticipated to be completed in early 2014, and has added a new track, to consider the local reliability impacts of a potential long-term outage at the San Onofre Nuclear Power Station (SONGS). The procurement targets and the schedule for solicitations proposed here are not presently tied to need determinations within the LTPP proceeding. Instead, in the near term, I view this proposal as moving in parallel to the ongoing LTPP evaluations of need – system and local, and with the new consideration of the outage at SONGS. In the longer term, I propose that procurement of energy storage be increasingly tied to need determinations within the LTPP proceeding.").

additional Energy Storage (beyond the 50 MW set by the 2012 LTPP decision) should be considered in Track 4, at least at the levels provided in the proposed Energy Storage decision.

It should be noted that deferment of portions of the storage targets is allowed, however the allowable deferment portion declines over time. By 2020, only up to 20% may be deferred, and only if a showing of unreasonableness of cost or lack of bids is provided:[178]

> To provide for cost containment, the Proposed Plan allowed each IOU to defer a declining percentage of its procurement targets upon an affirmative showing, such as unreasonableness of costs or the lack of a competitive number of bids in the energy storage auction. Under the Proposed Plan, an IOU would be permitted to defer from up to 40 percent of its 2014 procurement target with such a showing, from up to 30 percent of its 2016 procurement target with such a showing, and from up to 20 percent of its 2018 and 2020 procurement targets with such a showing.

By 2020, only 20% of that year's target can be deferred and deferred portions from previous years must be added to the next target. Consequently, it is reasonable to assume that by 2022, the entire 2020 target will be available, i.e. 612 MW. This is modest compared to the Governor's target, but consistent with the proposed decision in the storage proceeding. Those 612 MW of energy storage should be taken into account when formulating a decision in Track 4.

B. Added Energy Efficiency and Demand Response for peak cutting

Particular attention to peak cutting makes sense for long term energy needs, especially since needs are being assessed based on the worst peak periods which are much higher than average needs. Rather than using the methods historically employed to identify the worst peaks and then building to accommodate them, California is making progress toward managing our demand, but we can make further progress in changing our planning methodology creatively to actually change our peak rather than merely planning for it.

Energy Efficiency (EE) provides permanent peak (and non-peak) cutting while Demand Response (DR) has a much higher potential to cut peak need than is currently being utilized.[179] These two resources are also cheap and clean, and are consequently at the top of California's

[178] *Id.* At p. 37.

[179] R.12-0-014, Prepared Direct Testimony of Julia May on Behalf of the California Environmental Justice Alliance (CEJA), Before the Public Utilities Commission of the State of California, June 25, 2012, at 18-22. Discussing the large number of DR sources available today that are still not included in long term planning a decade out: "By 2020, significantly expanded DR options can be considered a standard assumption, and yet CAISO included zero DR resources in 2021, even though it identified about 2300 MW of DR for 2012." at 21.

Loading Order Priority.[180] The Chair of the U.S. Federal Energy Regulatory Commission (FERC), Jon Wellinghoff, also explained earlier this year that we can reduce peak loads in the U.S. by 20% using Demand Response.[181] A European Study, *Demand Response: a decisive breakthrough for Europe, How Europe could save Gigawatts, Billions of Euros, and Millions of tons of CO2*[182] found that widespread studies consistently found that DR resulted in major savings: 20-50% peak clipping and 10-15% overall consumption reduction. This year, Senior Advisor to Governor Jerry Brown and Director of the Governor's Office of Planning and Research blogged about Demand Response (and Energy Storage):[183]

> We are making progress in two more key areas, although California, for now, is not in the lead. Thanks to new developments and a key PUC proceeding, California will once again push the country forward on electrical storage. *We are also moving forward on the broader category of demand response, but we have plenty to learn on that topic, including from states on the east coast. . . .*
>
> Right now, PJM, a regional transmission organization for electric power in 13 states on the east coast, is probably the most sophisticated provider of demand response resources, which it describes as "end-use customers reducing their use of electricity in response to power grid needs, economic signals from a competitive wholesale market or special retail rates." This can take many forms, including an aggregation of residential users who agree to curtail use of air conditioners for a short period during times of peak demand. Used well, demand response can reduce load requirements, shave peaks, and increase the value of renewables.
>
> California's demand response programs, so far, are limited and do not include aggregation or sophisticated market mechanisms. [CAISO], the PUC, and the utilities are taking a close look at PJM's efforts and other approaches, and, *hopefully, we will see much more activity on this front in the near future.*

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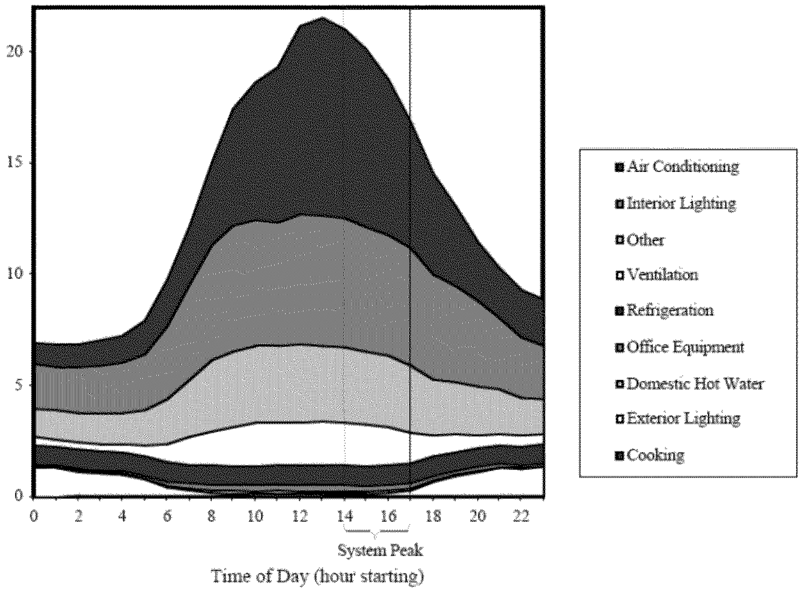
[180] In 2003, the Energy Commission and the CPUC agreed on a "loading order" for meeting electricity needs: the first resources that should be added are energy efficiency and demand response (at the maximum level that is feasible and cost effective), followed by renewables and distributed generation, and combined heat and power (also known as cogeneration), and finally efficient fossil sources and infrastructure development. California Energy Commission 2008, *2008 Integrated Energy Policy Report Update*, (IEPR), *available at* CEC-100-2008-008-CMF); *see also State of California Energy Action Plan II*: *Implementation Roadmap For Energy Policies* (September 21, 2005) *available at* http://docs.cpuc.ca.gov/word_pdf/REPORT/51604.pdf at pp. 3-6

[181] *"We can reduce our peak loads in this country by 20% using demand response – using assets on the customer's side of the meter that can be put in place to control loads and reduce costs. . . . "We have to embrace these trends, If we don't, they're going to run over us. . . ."* Demand Response – Embrace it or Get Run Over, Renewable Energy World article, Russell Ray, 1/5/13, *available at* http://www.renewableenergyworld.com/rea/blog/post/2013/01/demand-response-embrace-it-or-get-run-over?cmpid=rss.

[182] 2008, CapGemini in collaboration with VAASAETT and Enerdata, http://www.vaasaett.com/wp-content/uploads/2010/01/0805_Demand-Response_PoV_Final.pdf.

[183] Ken Alex, July 31, 2013, http://legalplanet.wordpress.com/2013/07/31/guest-blogger-ken-alex-saving-electricity-for-a-rainy-day/ (emphasis added).

Pushing EE and DR further makes far more sense than building new gas power plants given the costs and benefits. EE and DR tools for peak cutting are presently available and could greatly reduce the nearly 30% of California peak electricity use by air conditioning (which is about half commercial, half residential), rather than building new power plants to service these devices.[184] This CPUC graphic illustrates peak components, emphasizing air conditioning:[185]



One way to cut peak residential air conditioning use is automatic cycling: a demand response method where utilities control individual home units by turning them off for only a minute, then move to the next house with no noticeable effect by the occupants. The BASE

[184] California Public Utilities Commission, Frequently Asked Questions: How High is California's Electricity Demand, and Where Does Power Come From?, *available at* http://www.cpuc.ca.gov/cfaqs/howhighiscaliforniaselectricitydemandandwheredoesthepowercomefrom.htm. *See also* Richard E. Brown & Johnathan G. Koomey, Electricity Use in California: Past Trends and Present Usage Patterns, at 9 (May 2002); http://www.google.com/url?sa=t&rct=j&q=&esrc=s&frm=1&source=web&cd=1&ved=0CC8QFjAA&url=http%3A%2F%2Fwww.researchgate.net%2Fpublication%2F222529287_Electricity_use_in_California_past_trends_and_present_usage_patterns%2Ffile%2F3deec51c1e74eb21d4.pdf&ei=Z6BEUpTeFcm9iwLo1oBQ&usg=AFQjCNFSdWGLfXaqcm2iDm_G_in8GNR29Q&sig2=J9gBjvA-YWz2YvepgaAvHw&bvm=bv.53217764,d.cGE, p. 10 shows total state electricity during peak almost 30% from air conditioning (15% commercial, 14% residential). Figure 7, p. 18 below illustrates Commercial Building End-Use Load (GW).

[185] CPUC website FAQs: http://www.cpuc.ca.gov/cfaqs/howhighiscaliforniaselectricitydemandandwheredoesthepowercomefrom.htm, also *Electricity Use in California: Past Trends and Present Usage Patterns,* Richard E. Brown, Jonathan G. Koomey, May 2002, p. 9 and p. , http://enduse.lbl.gov/info/LBNL-47992.pdf, p. 10 shows total state electricity during peak almost 30% from air conditioning (15% commercial, 14% residential). Figure 7, p. 18 below illustrates Commercial Building End-Use Load (GW).

2020 report found that cycling can cut demand from air conditioning by 30-40%,[186] which translates to 9 to 12% of peak when air conditioning is 30% of peak.

Expanded energy efficiency funding (cheaper than new generation) for the most efficient new air conditioning units can also drastically cut need. These types of solutions can be implemented much faster than building new gas and are higher on the loading order. Again, according to the BASE 2020 report, funding the cost difference between the most efficient air conditioners and basic units on the market when people buy new ones can cut electricity use in the replaced units by 50%.[187] Moreover, an important recent study published in Science evaluates methods such as energy efficiency to achieve 80% Greenhouse Gas (GHG) cuts statewide by 2050.[188] It found that 1.3% cuts per year from EE over forecast demand over the next 40 years is both achievable and necessary to reach California's goal of 80% GHG cuts by 2050.

Furthermore, energy storage can be added to the mix. For example, the commercially available Ice Bear,[189] which makes ice at night using off-peak electricity and then uses it to feed cool air into commercial customers' existing air conditioning unit inputs during the day, can cut grid electricity use during hot peak summer hours by 90%.[190] Furthermore, since the ice is made at night and stored, it can take advantage of a clean off-peak source such as wind.

Such creative and clean packages of EE, DR (and storage) should be considered before allowing further gas procurement that adds to the atmospheric burden of GHGs and smog precursors.

[186] The BASE 2020 (Bay Area Smart Energy 2020), Bill Powers, P.E., Pacific Environment, evaluated cycling and found 30-40% reduction could be achieved , at p. 9, http://pacificenvironment.org/downloads/BASE2020_Full_Report.pdf .

[187] *Id.*

[188] *The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050: The Pivotal Role of Electricity,* James H. Williams, *et. al.,* 6 Science Vol. 335 (November 24 2011) pp. 53-59, https://www.sciencemag.org/content/335/6064/53.full.

[189] Ice Bear, Ice Bear Energy Storage System, http://www.ice-energy.com/ice-bear-energy-storage-system (last visited Sept. 12, 2013); DOE International Energy Storage Database, http://www.energystorageexchange.org/projects (last visited Sept. 12, 2013).

[190] Evaluation of Demonstration Project for ICE Bear Thermal Ice Storage System for Demand Shifting, submitted to SMUD by ADM Associates, November, 2006, https://www.smud.org/en/business/save-energy/energy-management-solutions/documents/Ice%20Bear%20Final%20Report.pdf.

C. *Additional Distributed Generation (DG)*

Distributed Generation – primarily rooftop solar – continues to make inroads to replace conventional generation in California.[191] Although CAISO did not include even the DG levels set in the Revised Scoping Memo, those levels were still relatively modest compared to California's goal of reaching 12,000 MW of DG by 2020 (which would amount to about 4600MW if the LA Basin and SDG&E region receive at least a proportional amount compared to demand, or about 38%[192]). If any additional generation is considered by the Commission in this track, preferred resources such as DG should provide it.

Key findings in a July 2013 report from the Lawrence Berkeley International Laboratories show that rooftop solar costs have continued to fall:[193]

- "Installed prices continued their precipitous decline in 2012 . . . "
- "Partial data for the first six months of 2013 indicate that installed prices have continued to fall . . . "
- "International experience suggests that greater near-term price reductions in the United States are possible . . ."

In addition, my previous Track 1 testimony discussed a study by CPUC consultants (the "Deep Dive") on DG which found that counter to expectations, a high DG scenario had *fewer* problems with flexibility than an all-gas scenario, refuting the assumption that gas resources are necessary to provide sufficient flexibility.[194] Track 4 should consider these findings as well.

Furthermore, an interesting analysis of DG Technical Potential presented by E3 during the CPUC's January 31, 2013 workshop[195] proposed a methodology for identifying local capacity requirements for local zones and calculating the ability of DG to reduce central station generation need. It found, for example, that 1,248MW of DG could avoid 1,012 MW to 1,611MW of central station generation in the LA Basin:

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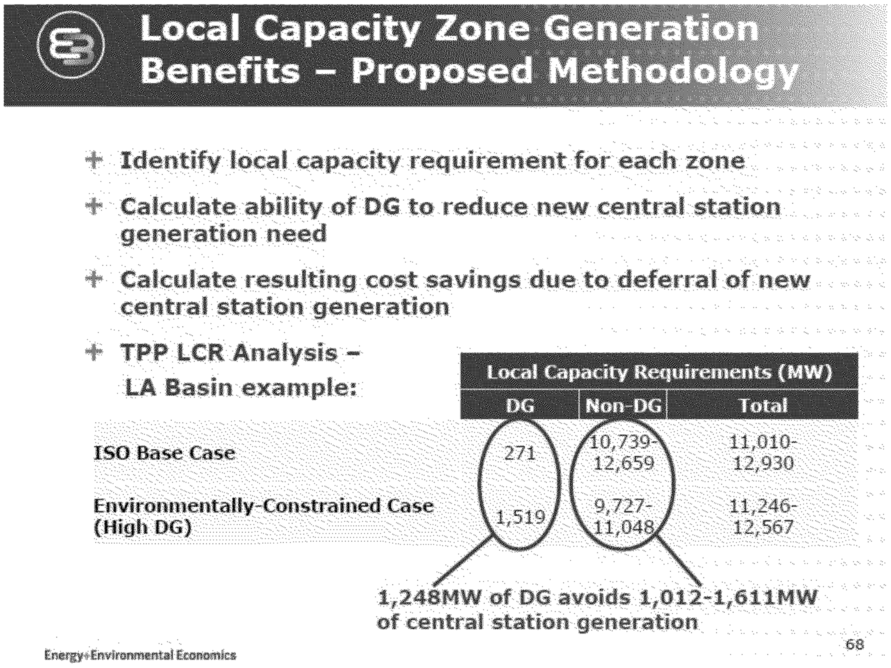
[191] R.12-03-014, Prepared Direct Testimony of Julia May on Behalf of the California Environmental Justice Alliance (CEJA), Before the Public Utilities Commission of the State of California, June 25, 2012, for example at pp. 23 (hereinafter Prepared Testimony of Julia May). "There is ample new evidence about the emerging economic competitiveness of DG, and benefits for supplying resources at peak load…"

[192] Calculated based on proportion of LA Basin + SDG&E Demand compared to statewide demand, using for example, the in the midcase – baseline CEC forecast at http://www.energy.ca.gov/2013_energypolicy/documents/2013-10-01_workshop/spreadsheets/.

[193] Tracking the Sun VI, Lawrence Berkeley National Laboratories (LBNL), July 2013, at pp. 1-2, http://emp.lbl.gov/sites/all/files/lbnl-6350e.pdf.

[194] Track 1 Prepared Testimony of Julia May, pages 23-26.

[195] California Public Utilities Commission, Renewable DG Technical Potential Workshop, at 68 (Jan. 31, 2013), *available at* http://www.cpuc.ca.gov/NR/rdonlyres/5F2B76C0-043D-46CA-8C41-1F67E3116999/0/Jan31_CPUC_RenewableDGTechnicalPotentialWorkshopSlides.pdf.

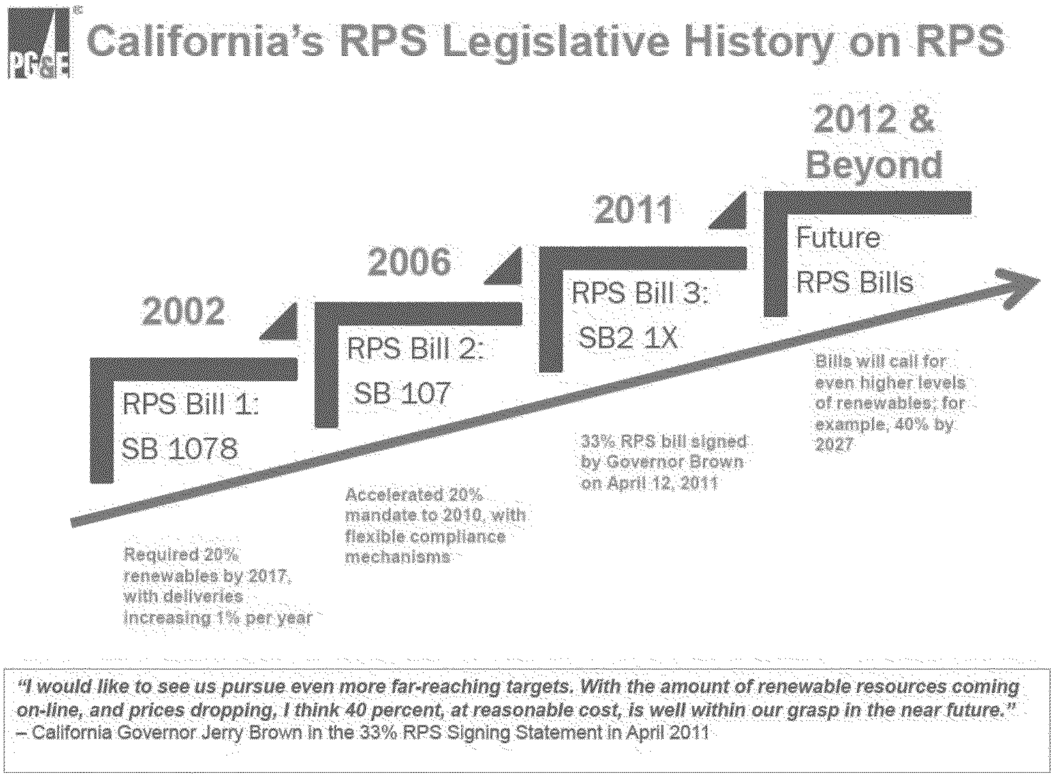


Such specific methods for fulfilling local capacity needs through real preferred resources should be increasingly applied, rather than assuming new gas is preferable, which is frequently considered the default because that is what has been done in the past. Barriers to increasing penetration of solar for fulfilling specific local capacity are not technological, but frequently a matter of updating analytical methods to apply to preferred resources, rather than just to gas. The Commission should remove those barriers in order to expand DG penetration in the LA Basin and San Diego, thereby further reducing need.

D. The RPS is likely to be expanded in the near future

It is likely that a higher Renewable Portfolio Standard (RPS) level (40 or 50%) will be mandated in the near future in California. Indeed, Hawaii already has a 40% RPS for 2030.[196] In California, as the feasibility of increased renewable penetration has steadily grown, as costs were reduced, and as the environmental benefits became more urgent, the RPS level steadily rose, as laid out in the PG&E slide below.[197] The slide identifies past, present, and future proposals in the California legislation:

[196] Database of State Incentives for Renewables and Efficiency, Hawaii: Incentives/Policies for Renewables & Efficiency, Renewable Portfolio Standard, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=HI06R (last updated May 24, 2013).
[197] Pacific Gas & Electric Company, PG&E and California's Renewable Portfolio Standard (RPS): Renewable Energy Policy and Strategy, at 4, *available at* http://berc.berkeley.edu/wp-content/uploads/2012/09/PGE-Californias-RPS.pdf.



Governor Brown "would like to see us pursue even more far-reaching targets. With the amount of renewable resources coming on-line, and prices dropping, I think 40 percent, at reasonable cost, is well within our grasp in the near future." In fact, Assemblyman Manuel Perez introduced a bill in the California legislature this year (AB-177) which would increase the RPS to 51% by 2030.[198] Moreover, AB-327 just passed by the state legislature in September and anticipated to be signed by the Governor shortly, removes the 33% ceiling on the state's RPS, meaning that 33% becomes a floor, not a ceiling.[199]

If progress is linear, an increase to 51% by 2030 would mean adding another 18% beyond the 2020 33% RPS in just 10 years, a 1.8% increase per year, or an added 3.6% by 2022. Regardless of how the details turn out, renewables are steadily lowering in cost and the logistical details of planning for high renewable penetration are fast developing, with a very likely outcome that greater than 33% renewables will be available in 2022.

[198] http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB177.
[199] http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB327.

Renewables have also been found to be the least risky investment for long-term energy planning (according to a report by Ceres, an organization providing analysis on sustainable investment and business practices).[200] It found "Placing too many bets on the conventional basket of generation technologies is the highest risk route."[201]

All of this information shows that the trends are strongly in favor of the need for, economic viability of, and increasing requirements for long term planning emphasizing clean renewable, and distributed energy rather than new gas generation.

VIII. Conclusion

There is no need for procuring gas powered electricity due to the SONGS retirement once the missing resources discussed above are included. It would be unnecessary and, given the dire need to avoid adding to the atmospheric burden of CO2 and smog precursors, harmful to procure additional gas resources, as well as prudent to wait until the transmission options, preferred resources, and other factors discussed above are included in new modeling to be provided next year. The deficiencies in assumptions used by the unfinished CAISO study should be corrected and modeled for evaluation next year. The expected result of the modeling should clearly show there is no need for new generation in the SONGS service area.

[200] Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know, How State Regulatory Policies Can Recognize and Address the Risk in Electric Utility, A Ceres Report, April 2012, at pp. 5, 6, 7, 8, 9, 12, 17, http://www.ceres.org/resources/reports/practicing-risk-aware-electricity-regulation
[201] *Id.* at p. 3.