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Center for Biological Diversity Comments on Preliminary Staff Assessment

Additional submitted attachment is included below.

CENTER for BIOLOGICAL DIVERSITY Because life is good.

September 12, 2016

Via e-comment
(https://efiling.energy.ca.gov/Ecomment/Ecomment.aspx?docketnumber=15-AFC-01)

California Energy Commission
Dockets Unit, MS-4
1516 Ninth Street
Sacramento, CA 95814-5512

Re: Puente Power Plant (15-AFC-01)
Comments on Preliminary Staff Assessment

Dear Commissioners:

The Center for Biological Diversity ("Center") appreciates the opportunity to provide these comments on the Preliminary Staff Assessment ("PSA") for the Puente Power Plant ("Project"). The Center is a non-profit organization with more than 1.1 million members and online activists and offices throughout the United States, including in Oakland, Los Angeles, and Joshua Tree, California. The Center's mission is to ensure the preservation, protection and restoration of biodiversity, native species, ecosystems, public lands and waters and public health. In furtherance of these goals, the Center seeks to reduce U.S. greenhouse gas emissions and other air pollution to protect biological diversity, the environment, and human health and welfare. Specific objectives include securing protections for species threatened by global warming, ensuring compliance with applicable law in order to reduce greenhouse gas emissions and other air pollution, and educating and mobilizing the public on global warming and air quality issues.

As set forth in detail below, the PSA fails to comply with the California Environmental Quality Act ("CEQA"), Public Resources Code § 21000 et seq., and the CEQA Guidelines, title 14, California Administrative Code, § 15000 et seq., particularly with respect to its discussion of greenhouse gas emissions, project objectives, and alternatives.[1] The Commission cannot lawfully approve the Project based on this PSA.

[1] While these comments from the Center focus on only a few issues, the Center also asserts that the PSA is deficient in its analysis of numerous other impacts, including but not limited to impacts to rare and imperiled species, coastal resources, and environmental justice. It is the Center's understanding that comments from the U.S. Fish and Wildlife Service, the California Coastal Commission, Sierra Club, Environmental Defense Center, California Environmental Justice Alliance, the City of Oxnard, and others have addressed or will address these additional deficiencies in detail.

Alaska . Arizona . California . Florida . Minnesota . Nevada . New Mexico . New York . Oregon . Vermont . Washington, DC

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I. Legal Background

The legal standards governing preparation of the PSA are clear. "The power plant site certification program of the State Energy Resources Conservation and Development Commission under Chapter 6 of the Warren-Alquist Act, commencing with Public Resources Code Section 25500" is a "certified regulatory program" for CEQA purposes. CEQA Guidelines § 15251(j). Although certified regulatory programs are exempt from certain requirements generally applicable to environmental impact reports under CEQA, the core policy goals and substantive standards of CEQA still apply. *Sierra Club v. Bd. of Forestry*, 7 Cal. 4th 1215, 1229-30 (1994); *POET, LLC v. State Air Res. Bd.*, 218 Cal. App. 4th 681, 714 (2013). The exemption for certified regulatory programs is thus construed narrowly and according to the strict language of the statute. *See Joy Rd. Area Forest & Watershed Assn. v. Cal. Dep't of Forestry & Fire Prot.*, 142 Cal. App. 4th 656, 668 (2006).

Accordingly, Commission staff must "prepare a preliminary and final environmental assessment of the proposed site and related facilities . . . that describes and analyzes the significant environmental effects of [the] project, the completeness of the applicant's proposed mitigation measures, and the need for, and feasibility of, additional or alternative mitigation measures." Cal. Code Regs., tit. 20, § 1742; *accord Ebbetts Pass Forest Watch v Dep't of Forestry & Fire Prot.* (2008) 43 Cal. 4th 936, 943; Pub. Res. Code § 21080.5(d)(3). The Presiding Member's Proposed Decision ("PMPD") similarly must contain "a description of potential significant environmental effects," "an assessment of the feasibility of mitigation measures and a reasonable range of alternatives that could lessen or avoid the adverse effects," and "if any significant effects are likely to remain even after the application of all feasible mitigation measures and alternatives," consideration of "whether economic, legal, social, technological or other environmental benefits of the project outweigh the unavoidable adverse effects." Cal. Code Regs., tit. 20, § 1745.5(b)(2); *see also id.*, § 1748(b)(5). Consistent with CEQA's fundamental substantive requirements, the Commission may not approve a Project if there are feasible mitigation measures or alternatives available that would lessen or avoid its significant environmental effects. Pub. Res. Code §§ 21002, 21002.1(b), 21081; Cal. Code Regs., tit. 20, § 1748(b)(5). If the Commission elects to proceed with the Project despite significant and unavoidable environmental impacts, it must adopt formal findings that specific considerations render infeasible mitigation measures and alternatives to reduce or avoid those impacts, and must further find that specific benefits of the project outweigh its significant environmental effects. Pub. Res. Code § 21081(a)(3), (b); Cal. Code Regs., tit. 20, § 1748(b)(5)(B).

"Just as for EIRs, environmental documents prepared by certified programs must use scientific and other empirical evidence to support their conclusions." Kostka & Zischke, Practice Under the California Environmental Quality Act § 21.17 (CEB 2016 supp.). The Commission also must provide written responses to substantive environmental issues raised in comments on the PSA and in evidentiary hearings. Cal.

Code Regs., tit. 20, §§ 1742(c), 1745.5(b)(17); *see Ebbetts Pass Forest Watch*, 43 Cal. 4th at 943.

II. The PSA Fails to Adequately Disclose, Analyze, Determine the Significance of, and Propose Mitigation for the Project's Greenhouse Gas Emissions and Climate Impacts

The PSA concludes that the Project's greenhouse gas emissions are less than significant. (PSA at 4.1-134, 135.)

Although the PSA references CEQA Guidelines section 15064.4, which provides guidance on greenhouse gas significance determinations, the PSA's significance criteria do not reflect the Guidelines' approach. Instead of an explicit numeric threshold or any of the factors discussed in Guidelines section 15064.4(b)(1) through (3), the PSA adopts a vague standard based on a evaluation "in the context of the electricity sector as a whole and the AB 32 Scoping Plan implementation requirements for the sector." (PSA at 4.1-117.) The PSA's significance determination also appears to rely on a finding of consistency with the Avenal precedent decision, under which the Commission "must" find that the Project will not increase the overall system heat rate for natural gas plants, will not interfere with existing renewable generation or integration of new renewables, and based on these two factors, will "reduce system-wide GHG emissions." (*Ibid.*)

Accordingly, the PSA does effectively establish a numerical significance threshold notwithstanding assertions to the contrary. "System-wide GHG emissions" are discernible, although the PSA fails to disclose or address them here. Accordingly, in order to demonstrate consistency with the Avenal precedent decision and to support the PSA's significance conclusions under CEQA, the Commission must not only follow CEQA's legal requirements but also provide substantial evidence that the Project will reduce system-wide GHG emissions. "[W]hen [an] agency chooses to rely completely on a single quantitative method to justify a no-significance finding, CEQA demands the agency research and document the quantitative parameters essential to that method. Otherwise, decision makers and the public are left with only an unsubstantiated assertion that the impacts—here, the cumulative impact of the project on global warming—will not be significant." *Ctr. for Biological Diversity v. Cal. Dep't of Fish & Wildlife*, 62 Cal. 4th 204, 228 (2015).

As discussed in detail below, the analysis offered in support of the PSA's conclusions is both inconsistent with CEQA's legal requirements and lacking in substantial evidence.

A. The PSA Fails to Establish an Adequate Baseline for Analysis of the Project's Greenhouse Gas Emissions.

The PSA fails to identify any clear and consistent baseline against which the Project's greenhouse gas impacts can be evaluated. "Before the impacts of a project can be assessed and mitigation measures considered, an EIR must describe the existing environment. It is only against this baseline that any significant environmental effects can be determined." *Cty. of Amador v. El Dorado Cty. Water Agency*, 76 Cal. App. 4th 931, 952 (1999); *see also* CEQA Guidelines § 15125(a). "[W]ithout such a description, analysis of impacts, mitigation measures and project alternatives becomes impossible." *Cty. of Amador*, 76 Cal. App. 4th at 953; *see also Save Our Peninsula Comm. v. Monterey Cty. Bd. of Supervisors*, 87 Cal. App. 4th 99, 119 (2001) ("Without a determination and description of the existing physical conditions on the property at the start of the environmental review process, the EIR cannot provide a meaningful assessment of the environmental impacts of the proposed project.") An agency's use of a legally inadequate baseline renders an environmental document inadequate as a matter of law. *See Communities for a Better Env't v. S. Coast Air Quality Mgmt. Dist.*, 48 Cal. 4th 310, 319, 322 (2010). Moreover, an agency wishing to deviate from the usual existing conditions baseline must justify the deviation by showing that a comparison between the Project and existing environmental conditions would be completely uninformative or affirmatively misleading. *See Neighbors for Smart Rail v. Exposition Metro Line Constr. Auth.*, 57 Cal. 4th 439, 457 (2013).

It is not clear what baseline—if any—the PSA used in assessing the Project's greenhouse gas emissions. Although the PSA's significance criterion requires the Commission to demonstrate that the Project will reduce "system-wide" emissions, the PSA does not quantify or otherwise characterize those emissions. The PSA references a net reduction in GHG emissions since 2001 from combined-cycle and boiler units (PSA at 4.1-125), but does not disclose current "system-wide" emissions or current emissions from simple-cycle gas combustion turbines like the Project. Absent a clear baseline, it is impossible to determine whether the Project will actually reduce "system-wide" emissions.

The PSA's comparison between the Project and the units it is designed to replace (MGS 1 and 2) fails for similar reasons. The PSA concludes Puente will be more efficient than MGS 1 and 2 (.509 $MTCO_2e$/MWh, as compared to .656-.724 $MTCO_2e$/MWh). (PSA at 4.1-116.) This superficially suggests that the Project will reduce emissions. However, the PSA acknowledges that overall mass emissions are likely to increase because MGS 1 and 2 have "very low annual capacity factors . . . due to their low level of efficiency." (4.1-116.) The magnitude of this increase, however, is impossible to discern because the PSA does not disclose existing baseline emissions from MGS 1 and 2.[2]

[2] The impossibility of evaluating this increase is exacerbated by the PSA's inconsistent characterizations of the Project's anticipated capacity factor, which range from 24.5 percent (PSA at 4.1-116) to 30 percent (PSA at 3-1) or 31 percent (PSA at 4.1-132.) This alone is a CEQA violation. "An accurate, stable, and finite project description is the *sine qua non* of an informative and legally sufficient EIR." *County of Inyo v. City of Los Angeles*, 71 Cal.App.3d 185, 193 (1977). Without an accurate description, decision-makers and the public cannot weigh a project's environmental costs and benefits, meaningfully consider mitigation measures, or evaluate alternatives. *See id.* at 192-9; *see*

B. The PSA's Reliance on California's Cap-and-Trade Program Is Inadequate to Support the Document's Conclusions

The PSA concludes that the Project complies with applicable regulations and plans for greenhouse gas reduction in part because the Project will be subject to California's cap-and-trade program. (PSA at 4.1-134.) Compliance obligations under the cap-and-trade regulation currently extend only through December 31, 2020. 17 Cal. Code Regs. § 95840(c). The Project, in contrast, is not expected to begin operating until June 2020, and has "an assumed operating life of 30 years." (PSA at 3-3.) Accordingly, a mere six months at most of the Project's 30-year operating life will be subject to the current cap-and-trade program.

The Project will be operating during a period of increasingly strict greenhouse gas reduction requirements. The Legislature recently adopted (and Governor Brown has now signed) SB 32, legislation requiring California to reduce emissions 40 percent below 1990 levels by 2030. Stats.2016, ch. 249 (Sen. Bill 32), § 2 (Health & Saf. Code § 38566, eff. Jan. 1, 2017). The 2014 update to the AB 32 Scoping Plan explains that in order to meet the state's long-term goals, the rate of emissions reductions must increase from about 1.0 percent per year through 2020 to about 5.2 percent per year through 2050.[3]

The role of the cap-and-trade regulation in achieving these increasingly steep reductions after 2020 is uncertain. Although SB 32 strengthened the state's greenhouse gas reduction goals, it did not specify cap-and-trade as a vehicle for attaining those goals. Moreover, AB 197—companion legislation to SB 32—specifically requires the Air Resources Board to prioritize "direct emission reductions" in achieving reductions beyond the 2020 limit. Stats.2016, ch. 250 (Asm. Bill 197), § 5 (Health & Saf. Code § 38562.5, eff. Jan. 1, 2017).

It is far from clear whether the cap-and-trade regulation can be extended beyond the end of 2020 under existing statutory authority. *Compare* Health & Saf. Code § 38551(b) (declaring intent of Legislature that "the statewide greenhouse gas emissions limit continue in existence and be used to maintain and continue reductions in emissions of greenhouse gases beyond 2020") *with* Health & Saf. Code § 38562(c) (authorizing Air Resources Board to adopt "a regulation that establishes a system of market-based declining annual aggregate emission limits for sources or categories of sources that emit greenhouse gas emissions, applicable from January 1, 2012, to December 31, 2020, inclusive").

Because virtually all of the Project's operational emissions will occur after 2020, while the current cap-and-trade program extends only through 2020, the Project's

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also CEQA Guidelines §15124 (requiring detail sufficient for "evaluation and review of the [project's] environmental impact").

[3] CAL. AIR RES. BD., FIRST UPDATE TO THE CLIMATE CHANGE SCOPING PLAN: BUILDING ON THE FRAMEWORK 33 (Fig. 6) (May 2014), *available at* https://www.arb.ca.gov/cc/scopingplan/document/updatedscopingplan2013.htm (visited Sept. 9, 2016).

participation in the AB 32 cap-and-trade program alone does not support the conclusion that its operational emissions will be consistent with applicable greenhouse gas reduction regulations and plans.

C. The PSA Fails to Evaluate the Project's Emissions in Light of Long-term, Science-based Greenhouse Gas Reduction Goals.

The PSA's LORS analysis with respect to greenhouse gases explicitly addresses only AB 32. (PSA at 4.1-130 to 131.) The analysis thus impermissibly omits any assessment of the Project's consistency with the science-based, long-term greenhouse gas reduction goals articulated in Executive Orders S-3-05 and B-30-15, which direct state agencies to undertake efforts to ensure that statewide emissions are reduced 40 percent below 1990 levels by 2030 and 80 percent below 1990 levels by 2050. These goals reflect a broad scientific understanding of the scale of emissions reductions necessary to stabilize the climate system.[4]

The PSA's failure to include any information or analysis regarding the Project's long-term consistency with climate science and state policy renders the document inadequate as a matter of law. *See, e.g.*, *Sierra Club v. Bd. of Forestry*, 7 Cal. 4th 1215, 1236 (1994) (complete absence of information made meaningful assessment of potentially significant impacts and development of mitigation measures impossible; "[i]n these circumstances prejudice is presumed"); *Bakersfield Citizens for Local Control v. City of Bakersfield*, 124 Cal. App. 4th 1184, 1198 (2004).

Indeed, the Supreme Court has cautioned that "over time consistency with year 2020 goals will become a less definitive guide, *especially for long-term projects that will not begin operations for several years*. An EIR taking a goal-consistency approach to CEQA significance may in the near future need to consider the project's effects on meeting longer term emissions reduction targets." *Ctr. for Biological Diversity v. Cal. Dep't of Fish & Wildlife*, 62 Cal. 4th at 223 & n.6 (emphasis added). The footnote following this warning specifically cites Executive Orders S-3-05 and B-30-15 as well as the First Update to the Climate Change Scoping Plan.

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[4] *See, e.g.*, FIRST UPDATE TO THE CLIMATE CHANGE SCOPING PLAN, *supra* note 3 at 1 ("The State's 2050 objective of reducing emissions to 80 percent below 1990 levels, as reflected in Executive Order S-3-05 . . . is consistent with an Intergovernmental Panel on Climate Change (IPCC) analysis of the emissions trajectory that would stabilize atmospheric GHG concentrations at 450 parts per million carbon dioxide equivalent (CO2e) and reduce the likelihood of catastrophic climate change"); CAL. AIR RES. BD., CLIMATE CHANGE SCOPING PLAN: A FRAMEWORK FOR CHANGE 4 (Dec. 2008), *available at* https://www.arb.ca.gov/cc/scopingplan/document/scopingplandocument.htm (visited Sept. 9, 2016) (explaining that the 2050 goal in EO S-3-05 "represents the level scientists believe is necessary to reach levels that will stabilize climate [*sic*]"); *see also id.* at 117 ("Climate scientists tell us that the 2050 target represents the level of greenhouse gas emissions that advanced economies must reach if the climate is to be stabilized in the latter half of the 21st century").

The PSA's failure to discuss the Project's emissions in light of the state's science-based, long-term goals not only violates legal requirements but also deprives the document's conclusions of substantial evidentiary support. Although the PSA mentions California's goal of reducing emissions 40 percent below 1990 levels by 2030, it does so only in the context of discussing the cap-and-trade program (*id.* at 4.1-130); as previously discussed, however, the cap-and-trade program currently ends in 2020, and cannot serve as the basis for a conclusion that the Project will be consistent with California's long-term emission reduction goals. Moreover, nothing in the document addresses the Project's long-term emissions relative to California's 2050 climate goals, even though the Project is expected to operate through 2050. (*See* PSA at 3-3.)

D. The PSA's Conclusions Regarding Displacement of Older Gas-Fired Generation and Renewable Generation Lack Evidentiary Support.

1. The PSA Contains Inadequate Evidence to Support a Conclusion that the Project Will Displace Only Older, Less Efficient Generation.

The PSA's significance conclusion—and its conclusion that the Project is consistent with the Avenal precedential decision—turn in part on the assumption that all generation from the Project will displace older, less efficient generation. For at least two reasons, there is insufficient evidence to support this assumption.

First, the PSA does not account for the possibility of demand growth in the local capacity area ("LCA") or the "system" as a whole. Rather, the PSA appears to depend entirely on assumptions regarding the instantaneous displacement of generation at the time of dispatch. (*See* PSA 4.1-113, 114 (dispatch of new generation "unavoidably displaces" existing generation).) If demand were to grow in the LCA or system-wide between now and 2050,[5] it is at least reasonably foreseeable that the Project might not always displace—but may instead be dispatched concurrently with—both older, less efficient generation and newer, more efficient future generation. Even if the Project is more efficient than other generation, incremental gains in efficiency could be offset by increases in system-wide demand, leading to an increase in overall emissions compared to existing conditions. *Cf. Ctr. for Biological Diversity v. Nat'l Highway Traffic Safety Admin.*, 538 F.3d 1172, 1216-17 (9th Cir. 2008) (requiring analysis of cumulative climate impact of rule that did not actually decrease greenhouse gas emissions, but rather resulted in slower emissions growth).

Second, the PSA assumes that dispatch will always go to the cheapest resource, which according to the PSA will always be the most efficient resource. (PSA at 4.1-124 to 125.) The PSA thus assumes that the Project will by definition reduce greenhouse gas

[5] The Energy Commission expects overall California electricity demand to continue growing through 2026. *See* CAL. ENERGY COMM'N, 2015 INTEGRATED ENERGY POLICY REPORT 132-38 (docketed June 29, 2016), available at http://www.energy.ca.gov/2015_energypolicy/ (visited Sept. 9, 2016).

emissions. (PSA at 4.1-129.) Yet the PSA itself contains a number of caveats that undermine the reasonableness of these assumptions. For example, the PSA concedes both that the ISO's dispatch procedures are confidential and that the number of hours the Project ultimately will operate are unknown. (*Ibid.*) The PSA also acknowledges that dispatch and heat rate relationships are more complicated than theory would indicate; sometimes less-efficient smaller peaker plants are dispatched before larger plants that take a longer time to start up. (PSA at 4.1-126 to 127; *see also id.* at 4.1-128 (explaining that Project will take 90 minutes to start up).) The PSA does not adequately address whether smaller, less-efficient peaker plants in the LCA can be started up more quickly. Finally, the PSA admits that the Project may operate up to ten times more often than older, less-efficient peakers in the LCA. (PSA at 4.1-132 to 133 (comparing Project's estimated 31 percent capacity factor to LCA average of 3.5 percent).)

Substantial evidence may include "reasonable assumptions," but only where "predicated upon facts" (Guidelines §§ 15064(f)(5), 15384(b); see also *Ctr. for Biological Diversity v. Cal. Dep't of Fish & Wildlife*, 62 Cal. 4th at 228.) Here, the PSA does not provide a factual basis demonstrating that its assumptions are reasonable.

2. The PSA's Assumption that the Project Will Never Displace Renewable Generation Is Unsupported.

The PSA concludes that the Project will not displace existing renewables and will facilitate integration of new renewable generation. (PSA at 4.1-134 to 135). Again, however, the assumptions underlying this conclusion lack a sound factual basis in the document.

First, the PSA contains no information about the projected availability, relative cost, or dispatch procedures for renewables in the LCA. This information is necessary in order to establish that the Project will never displace renewable generation.

Second, this section of the PSA largely ignores the changing legal landscape governing renewable generation in California. The PSA's conclusions rest on the assertion that at renewable penetration rates below 33 percent, new gas-fired generation always displaces less efficient gas-fired generation. (PSA at 4.1-124.) Starting in 2021, however, about six months after the Project begins operation, renewable penetration in California will be *required* to exceed 33 percent. Pub. Util. Code §§ 399.11(a) (requiring 33 percent renewable generation by end of 2020 and 50 percent by end of 2030), 399.15(b)(2)(B) ("For the following compliance periods, the quantities shall reflect reasonable progress in each of the intervening years sufficient to ensure that the procurement of electricity products from eligible renewable energy resources achieves 25 percent of retail sales by December 31, 2016, 33 percent by December 31, 2020, 40 percent by December 31, 2024, 45 percent by December 31, 2027, and 50 percent by December 31, 2030. The commission shall establish appropriate three-year compliance periods for all subsequent years that require retail sellers to procure not less than 50 percent of retail sales of electricity products from eligible renewable energy resources."). Indeed, renewable penetration may *exceed* 50 percent even before 2030. Pub. Util. Code

§ 399.15(b)(3) ("The commission may require the procurement of eligible renewable energy resources in excess of the quantities specified in paragraph (2)."). The PSA's analysis explicitly addresses only a scenario where renewable penetration is below 33 percent—a scenario that will be almost completely inapplicable to this Project once it begins operation.

Third, the PSA states that natural gas generation is needed for balancing and load-following until at least the mid-2020s. (PSA at 4.1-119 to 121.) Again, however, the Project is expected to operate until 2050. The PSA contains no analysis of whether the Project will continue to provide these services—or instead will begin to displace lower-carbon options like energy storage—as the grid develops over the next few decades. *See, e.g.*, Pub. Util. Code §§ 2835-2839; Cal. Pub. Util. Comm'n, Decision No. D.13-10-040 (Oct. 21, 2013).

In sum, the PSA's CEQA significance conclusions, and its conclusion regarding consistency with the Avenal precedential decision, lack both legal and evidentiary support.

III. Project Objectives Are A Critical Foundational Element of CEQA Review.

CEQA requires a statement of the objectives of the project and a description of the Project in sufficient detail so that the impacts of the project can be assessed. CEQA Guidelines § 15124. CEQA requires an accurate, clear and stable description of the Project and its impacts:

> [A]n accurate, stable and finite project description is the *sine qua non* of an informative and legally sufficient EIR." (*County of Inyo v. City of Los Angeles* (1977) 71 Cal.App.3d 185, 199.) However, "[a] curtailed, enigmatic or unstable project description draws a red herring across the path of public input." (*Id.* at p. 198.) "[O]nly through an accurate view of the project may the public and interested parties and public agencies balance the proposed project's benefits against its environmental cost, consider appropriate mitigation measures, assess the advantages of terminating the proposal and properly weigh other alternatives . . . . (*City of Santee v. County of San Diego* (1989) 214 Cal.App.3d 1438, 1454.)

San Joaquin Raptor Rescue Center v. County of Merced, 149 Cal. App. 4th 645, 655 (2007); *see also Sacramento Old City Assn. v. City Council*, 229 Cal. App. 3d 1011, 1023 (1991); *Stanislaus Natural Heritage Project v. County of Stanislaus*, 48 Cal. App. 4th 182, 201 (1996); *Berkeley Keep Jets Over the Bay Com. v. Board of Port Comrs.*, 91 Cal. App. 4th 1344, 1358 (2001).

The project objectives frame the alternatives analysis which is critical to an adequate CEQA process. The purpose of alternatives analysis in an environmental review document under CEQA is to enable the agency or commission to fulfill the statutory requirement that feasible alternatives that avoid significant environmental impacts must be implemented.

> [I]t is the policy of the state that public agencies should not approve projects as proposed if there are feasible alternatives or feasible mitigation measures available which would substantially lessen the significant environmental effects of such projects, and that the procedures required by this division are intended to assist public agencies in systematically identifying both the significant effects of proposed projects and the feasible alternatives or feasible mitigation measures which will avoid or substantially lessen such significant effects.

Pub. Res. Code § 21002. The statutory language and case law make it quite clear that the Legislature intended CEQA's environmental review process and procedures to be utilized to make determinations regarding feasible alternatives and mitigation measures based on a robust analysis.

Nothing in CEQA states that an agency must meet all of the applicant's proffered objectives in evaluating "feasible" alternatives or mitigation measures. The statutory definition of "feasible" does not even mention the applicant's objectives. Pub. Res. Code § 21061.1. Similarly, nothing in CEQA states that an alternative may be found infeasible solely due to a conflict with one of the applicant's objectives. In fact, the CEQA Guidelines expressly provide that a feasible alternative may *impede* achievement of the project objectives to some degree. *See* CEQA Guidelines § 15126.6(a), (b).

Indeed, if applicants could thwart consideration of all potentially feasible alternatives simply by adopting overly narrow objectives, CEQA would be rendered meaningless. *See Kings County Farm Bureau v. City of Hanford*, 221 Cal. App. 3d 692, 736-37 (1990) (holding that applicant's prior commitments could not foreclose analysis of alternatives). As the Commission has stated:

> A reasonable, feasible alternative must be one that meets most basic project objectives while avoiding or substantially lessening any of the significant effects of the project. [CEQA Guidelines, § 15126.6(a).] Stating project objectives too narrowly or too specifically could artificially limit the range of reasonable, feasible alternatives to be considered.
> . . .
>
> The evidence leads us to conclude that the Applicant defined its objectives so narrowly as to preclude a reasonable range of alternatives. While it is true that a project's objectives should guide the selection of alternative sites for analysis, when objectives are defined too narrowly, the analysis of alternative sites may be inadequate. (*City of Santee v. County of San Diego* (1989) 214 Cal. App. 3d 1438, 1455.)

Final Commission Decision, Chula Vista Energy Upgrade Project, June 2009 (07-AFC-4) CEC-800-2009-001-CMF ("Chula Vista Decision") at 26 (finding that applicant had not met its duty to analyze a reasonable range of alternatives). As discussed in detail below, the PSA improperly adopted the applicant's objectives without taking into account the State's and the Commission's policies and goals including regarding the goals for renewable energy production and storage and other important considerations. As a result, the project objectives that form the basis for CEQA review of this Project unlawfully limit the meaningful range of alternatives to the project that may avoid and/or minimize significant impacts to resources.

A. The Project Objectives Relied on in the PSA Are Improper

Four of the first five Project Objectives simply restate what the Applicant seeks. PSA at 1-3. These are not proper project objectives and unfairly narrow the scope of review. Most egregious is the first Project Objective, which expressly incorporates fulfilling the terms of a Power Purchase Agreement (PPA) between NRG and SCE:

- Fulfill NRG's obligations under its 20-year Resource Adequacy Purchase Agreement (RAPA) with SCE requiring development of a 262-MW nominal net output of newer, more flexible and efficient natural-gas generation [1]

  (FN 1. On May 26, 2016 the California Public Utilities Commission approved a 20 year contract between SCE and NRG to provide electrical generating power from the P3.)

Because the PPA was entered into and approved by the CPUC *without any CEQA compliance*, the existence of the PPA cannot be allowed to undermine full and fair CEQA compliance by the Commission in this matter. The Center has consistently advocated for a broad formulation of project objectives that would allow the Commission to consider other energy sources including but not limited to various renewable energy technologies, as well as efficiency and conservation, as alternatives to any proposed power plant. In this instance, for example, distributed solar power on homes, businesses, and parking lots or other relatively small scale solar projects in this area, increased storage capacity, and/or efficiency measures and conservation, could avoid all or most of the significant impacts of the proposed project while contributing to achieving the Commission's and the State's goals regarding renewable energy development and storage. The Commission *cannot* lawfully rely on the applicant's overly narrow project objectives such that no meaningful alternatives could be considered before undertaking environmental review.

Three of the next four Project Objectives simply restate the Applicant's proposal, and as a result are too narrowly tailored to the Applicant's proposal to allow adequate environmental review and alternatives analysis:

- Provide an efficient, reliable, and predictable power supply by using a simple-cycle, natural gas–fired combustion turbine to replace the existing once-through cooling (OTC) generation;

- Support the local capacity requirements of the California Independent System Operator (CAISO) Big Creek/Ventura local capacity reliability (LCR) area;

- Develop a 262-MW nominal net power-generating plant that provides operational flexibility with rapid-start and fast-ramping capability;

- Be designed, permitted, built, and commissioned by June 1, 2020;

PSA at 1-3. These objectives should be revised. In particular, while supporting local capacity reliability may be an important project objective, it can clearly be accomplished in more than one way.

This issue has been raised by the Center before and in other matters Staff did not simply parrot the Applicant's proposal but developed a broader set of objectives. As Staff noted at hearing on the Hidden Hills Solar Electric Generating Station Project, if the project objective is the project proposal itself, then it is too narrow to provide for Staff to consider a range of alternatives.

> [T]he overarching purpose of an alternatives analysis is to foster meaningful public participation and informed decision making. So if it's constrained to meet the applicant's wishes it makes it very difficult to do that full analysis. . . . The ones that I disregarded was, of course, well, the one about using [] proprietary technology in another utility-scale project, further proving the technical and economic viability of the technology. That's -- that's really -- so this -- here's the proposed project and here's the objectives that says implement the proposed project. And so that seemed way to tightly – way too focused on the proposed project for it to be -- for me to feel like it should be considered in the alternative analysis.

Hidden Hills Solar Electric Generation Station Project (11-AFC-02) ("HHSEGS"), Tr. 3/18/13 at 109-110, TN# 2935). Staff discussed why various objectives that simply mirrored the Applicant's proposal were eliminated including an objective that was removed that would require complying with provisions of a power purchase agreement:

> [T]he alternatives analysis does not have to address the applicant's contractual obligations. As far as targeting, having the project online by a particular [date] . . . [staff] would have no way of knowing whether an alternative could be online by a particular date, whether the proposed project even could be online by a specific date, assuming that there's no hiccups in the -- in the schedule.

HHSEGS, Tr. 3/18/13 at 110-11, TN# 2935. It is unclear why Staff in this instance has backtracked on this critical issue. It is entirely improper for the Staff in this matter to simply adopt the Applicant's proffered project objectives, particularly the objective framed around meeting the terms of the PPA, in a manner that unlawfully limits the alternatives and environmental analysis.

B. Because the Project Objectives Are Overly Narrow, the PSA Ignores Feasible Alternatives and California's Renewable Energy Goals.

As explained above, the project objectives must be reformulated to provide full and meaningful environmental review including analysis of a range of feasible alternatives. The Center submitted extensive testimony to the California Public Utilities Commission that addresses the purported "need" for a gas-fired power plant project at this location and other ways that any anticipated local capacity requirements for the CAISO Big Creek/Ventura local capacity reliability area could be fulfilled with renewable energy sources, storage, conservation measures and efficiency. That testimony from Bill Powers, PE and the accompanying exhibits are attached hereto.

Among other critical issues, Mr. Powers discusses the availability of preferred resources to fulfill the amount of stated need in the Moorpark sub-area: "The Southern California Regional Energy Network has identified 200 MW of preferred resources available for the Moorpark sub-area that will eliminate any need for the procurement of gas fired generation."[6] The availability of these large amounts of preferred resources must be considered in a revised alternatives analysis. Moreover, as discussed *supra* in Part II.D.2, the PSA largely ignores the changing legal landscape in California, specifically new legislation increasing Renewable Portfolio Standard requirements to 50 percent by 2030 and mandating procurement of substantial energy storage resources. *See, e.g.*, Pub. Util. Code §§ 399.11(a), 399.15(b)(2)(B), (b)(3) (establishing additional RPS requirements); Pub. Util. Code §§ 2835-2839, 9620(c) (establishing energy storage requirements); Stats.2020, ch. 469 (Assembly Bill 2514), § 1 (stating legislative findings and declarations re necessity and purpose of energy storage requirements); Cal. Pub. Util. Comm'n, Decision No. D.13-10-040 (requiring investor-owned utilities to procure 1,325 MW of energy storage).

IV. The Alternatives Analysis in the PSA Fails to Meet CEQA's Requirements

An EIR "must consider a reasonable range of potentially feasible alternatives that will foster informed decisionmaking and public participation." CEQA Guidelines § 15126.6(a). The Supreme Court has underscored the importance of the analysis of alternatives and mitigation: "The core of an EIR is the alternatives and mitigation sections" and the alternatives should "offer substantial environmental advantages over the proposed project." *Citizens of Goleta Valley v. Bd. of Supervisors*, 52 Cal. 3d 553, 564, 566 (1990). "One of an EIR's major functions . . . is to ensure that all reasonable

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[6] Cal. Pub. Util. Comm'n, Proceeding No. A.14-11-016, Testimony of Bill Powers, P.E. at p. 24 and Exhibit 23 (attached).

alternatives to proposed projects are thoroughly assessed by the responsible official." *Wildlife Alive v. Chickering*, 18 Cal. 3d 190, 197 (1976).

Under CEQA, a lead agency may not approve a project if there are feasible alternatives that would avoid or lessen its significant environmental effects. Pub. Res. Code §§ 21002, 21002.1(b). To this end, the alternatives discussion "shall focus on alternatives to the project . . . which are capable of avoiding or substantially lessening any significant effects of the project, even if these alternatives would impede to some degree attainment of the project objectives, or would be more costly." CEQA Guidelines § 15126.6(b). The agency is required to consider a range of potentially feasible alternatives to a project, or to the location of a project, that would feasibly attain most of the basic objectives while avoiding or substantially lessening any of the significant environmental impacts. *Save Round Valley Alliance v. County of Inyo*, 157 Cal. App. 4th 1437, 1456 (2007).

Environmental review documents must provide "sufficient information about each alternative to allow meaningful evaluation, analysis and comparison with the proposed project." CEQA Guidelines § 15126.6(d); *Citizens of Goleta Valley*, 52 Cal. 3d at 564-65. It is the Commission's duty to consider alternatives and make findings regarding feasibility. As one court put it,

> Since CEQA charges the agency, not the applicant, with the task of determining whether alternatives are feasible, *the circumstances that led the applicant in the planning stage to select the project for which approval is sought and to reject alternatives cannot be determinative of their feasibility*. The lead agency must independently participate, review, analyze and discuss the alternatives in good faith.

Kings County Farm Bureau, 221 Cal. App. 3d at 736 (emphasis added). Thus, the Applicant's narrow interest in constructing only one type of power plant project using only one specific technology, and its interest in private contracts it has entered into such as a PPA, cannot be the primary determinants of the feasibility of alternatives. The environmental review for this proposed project must be revised to address a range of feasible alternatives that could avoid significant impacts to the environment based on a properly formulated set of project objectives.

As explained above, CEQA expressly provides that a feasible alternative may *impede* achievement of the project objectives to some degree. *See* CEQA Guidelines § 15126.6(a), (b). The applicant's objective cannot be used to limit consideration of all potentially feasible alternatives to avoid potentially significant impacts of a project. *See Kings County Farm Bureau*, 221 Cal. App. 3d at 736-37 (holding that applicant's prior commitments could not foreclose analysis of alternatives); Chula Vista Decision at 26 (finding that applicant had not met its duty to analyze a reasonable range of alternatives). Similarly, an applicant's *mere assertion* that a condition or alternative will not be feasible for them to build on their preferred timeline does not render an alternative *economically* infeasible. On the contrary, recent decisions have clarified that a finding of economic infeasibility must be based upon *quantitative, comparative evidence* showing that the alternative would render the project economically impractical. *See, e.g., Save Round Valley Alliance v. County of Inyo*, 157 Cal. App. 4th 1437, 1461-62 (2007) (holding that applicant's inability to achieve "the same economic objectives" under a proposed alternative does not render the alternative economically infeasible); *Uphold Our Heritage v. Town of Woodside*, 147 Cal. App. 4th 587, 600 (2007) (requiring evidence that comparative marginal costs would be so great that a "reasonably prudent property owner" would not proceed with the project); *Preservation Action Council v. City of San Jose*, 141 Cal. App. 4th 1336, 1356-57 (2006) (holding that evidence of economic infeasibility must consist of facts, independent analysis, and meaningful detail, not just the assertions of an interested party).

In order to make such a finding the Commission would need to consider the economics as a whole, not just the Applicant's own concerns including their ability or inability to fulfill PPA deadlines or make the project "financeable." The PSA provides no quantitative, comparative evidence regarding the economic feasibility of the various alternatives.

In sum, the petitioner's narrow interest in constructing only one type of gas-fired power plant project using only one specific technology, and its interest in a PPA (a private contract it has entered into), cannot be the primary determinants of the feasibility of alternatives. Because the PSA fails to address a range of feasible alternatives based on a properly formulated set of project objectives (including for example a true no project alternative, a distributed solar alternative, a storage-based alternative, and conservation and efficiency measures), the environmental review must be fundamentally revised and re-circulated for public comment and input.

Thank you for your consideration of these comments.

Sincerely,

Kevin Bundy
Senior Attorney

Lisa Belenky
Senior Attorney

Attachment: A.14-11-016. CBD, Testimony of Bill Powers, P.E. (with Exhibits 2-30)

Docket:	A.14-11-016
Exhibit Number:	
Commissioner:	Michel P. Florio
ALJ:	Regina DeAngelis
Witness	Bill Powers, P.E.

**OPENING TESTIMONY OF BILL POWERS, P.E.
ON APPLICATION OF SOUTHERN CALIFORNIA EDISON
COMPANY (U 338-E) FOR APPROVAL OF THE RESULTS OF ITS 2013 LOCAL
CAPACITY REQUIREMENTS REQUEST FOR OFFERS FOR THE MOORPARK SUB-AREA ON BEHALF OF
CENTER FOR BIOLOGICAL DIVERSITY**

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Dated: April 8, 2015

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OPENING TESTIMONY OF BILL POWERS, P.E.
ON BEHALF OF
CENTER FOR BIOLOGICAL DIVERSITY

This opening testimony is offered by Bill Powers, P.E., Powers Engineering, 4452 Park Blvd., Suite 209, San Diego, California, 92116. He provided expert testimony in the 2012 LTPP Track 1 and Track 4 proceedings, as well as in the SDG&E applications to enter into a Power Purchase Tolling Agreements with Pio Pico Energy Center, LLC and Carlsbad Energy Center, LLC. Mr. Powers is also a party in SCE's application for approval of the results of its 2013 local capacity requirements request for offers for the LA Basin.

Mr. Powers is a registered professional mechanical engineer in California with 30 years of experience in the energy and environmental fields. He is the author of the March 2012 *Bay Area Smart Energy 2020* strategic energy plan. He has written numerous articles on the strategic cost and reliability advantages of local renewable energy over large-scale, remote, transmission-dependent renewable resources. Mr. Powers has involved in the permitting of numerous peaking gas turbine, microturbine, and internal combustion engine cogeneration plants in California. He has a B.S. in mechanical engineering from Duke University and an M.P.H. in environmental sciences from the University of North Carolina – Chapel Hill. Mr. Powers' complete resume is provided as Exhibit PE-02.

I. Introduction

Q1. In this application, SCE requests that Commission approve 262 MW of gas-fired generation and 12 MW of preferred resources to meet the need for the Moorpark sub-area authorized in D.13-02-015. Is this consistent with California law?

A1. No. Pursuant to Public Utilities Code section 454.5, unmet energy needs must be met in a statutorily-defined preferred resources loading order. SCE has failed to conduct the RFO in such a manner and approval of the results of its

RFO would be in violation of the California law as well as the Commission's mission to "serve[] the public interest by protecting consumers and ensuring the provision of safe, reliable utility service and infrastructure at reasonable rates, with a commitment to environmental enhancement and a healthy California economy."

Q2. Are the results of SCE's 2013 LCR RFO for the Moorpark sub-area a reasonable means to meet the 215 MW to 290 MW of identified LCR need determined in D.13-02-015 for the Moorpark sub-area?

A2. No, for four reasons: 1) There is no set-aside for gas-fired generation in the Moorpark sub-area in D.13-02-015, yet A.14-11-016 seeks approval of 262 MW of gas-fired generation out of 274.2 MW of total capacity in the application, 2) the operational SCE-owned 49 MW McGrath peaker unit was not included in CAISO modeling and offsets 49 MW of need authorization, 3) the Commission assumes that at least 50 MW of preferred resources will be used to meet the Moorpark sub-area need authorization,[1] not 12.2 MW of preferred resources as proposed by SCE, and 3) the need authorization is unreasonable in the context of changed circumstances since the decision was issued that have eliminated the need for the authorized capacity.

Q3. Did SCE confirm that its 49 MW McGrath peaker unit, operational since November 2012, was not included in the CAISO modeling that is the basis for the D.13-02-015 Moorpark sub-area need authorization?

A3. Yes. SCE states in its reply to the CBD protest of A.14-11-016 that the 49 MW McGrath peaker, operational since November 2012,[2] was not included in CAISO modeling.[3]

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[1] CPUC Rulemaking R.13-12-010, *Assigned Commissioner's Ruling Technical Updates to Planning Assumptions and Scenarios for Use in the 2014 Long Term Procurement Plan and 2014-15 CAISO TPP*, May 14, 2014, p. 29. "At least 350 MW of preferred resources located in the West LA Basin and at least 50 MW of preferred resources located in Big Creek/Ventura are assumed to be procured as part of the authorization in D.13-02-015."

[2] SCE, *SCE-02 Vol. 09, 2015 General Rate Case – Generation, Volume 9 – Peakers*, November 2015, p. 3.

[3] SCE, *A.14-11-016 - Southern California Edison Company's (U 338-E) Reply to Protests to Its Application for Approval of the Results of Its 2013 Local Capacity Requirements Request for Offers for the Moorpark Sub-Area*, January 22, 2015, p. 10.

Q4. Did SCE know the Commission assumed at least 50 MW of its Moorpark sub-area procurement would be preferred resources when it submitted A.14-11-016?

A4. Yes. SCE is a party in the 2014 LTPP proceeding. The assumptions defined by the Commission in the 2014 LTPP proceeding were published in May 2014. SCE filed A.14-11-016 in November 2014, six months after the Commission assumed SCE would contract for at least 50 MW of preferred resources.

Q5. Didn't SCE argue against the Commission authorizing any procurement in the Moorpark sub-area in the 2012 LTPP Track 1 proceeding addressed in D.13-02-015?

A5. Yes. As stated in D.13-02-015, SCE recommended deferring authorization for procuring additional local capacity in the Moorpark sub-area of the Big Creek/Ventura local area until the next LTPP cycle in 2014. SCE also indicated that newer technology of various sizes is more likely to be the replacement generation in the Moorpark sub-area, which may be able to be built in 5 to 7 years.[4]

Q6. Why did the Commission overrule SCE's judgment on the (lack of) need for additional LCR capacity in the Moorpark sub-area?

A6. The Commission unreasonably determined that CAISO was more competent to assess SCE's need than SCE. D.13-02-015 states:[5]

> We cannot agree with DRA, SCE and others that it is reasonable to wait to authorize procurement in the Big Creek/Ventura local area. Depending on assumptions, the ISO forecasts a need for the Moorpark sub-area of the Big Creek/Ventura local area, at least some of which must be filled by generation with similar characteristics to the current OTC plants.

Q7. On this basis, the exclusive reliance by the Commission on modeling conducted by CAISO, the Commission determined in D.13-02-015 that

[4] D.13-02-015, pp. 68-69.
[5] Ibid, p. 72.

"There is an immediate need to begin a procurement process to meet LCR needs of between 215 and 290 MW in the Moorpark sub-area."?[6]

A7. Yes.

Q8. What are the changed circumstances since D.13-02-015 was issued that have eliminated the need identified in the Moorpark sub-area?

A8. The changed circumstances since the issuance of D.13-02-015 include:

- Continued actual unchanged or declining peak demand in SCE service territory, which includes the Moorpark sub-area;
- 49 MW of operational McGrath peaker capacity was erroneously excluded from CAISO modeling for the Moorpark sub-area in Track 1 and must be deducted from the Moorpark sub-area need authorization in D.13-02-015;
- An increase in SCE's net-metered solar target from approximately 850 MW under the California Solar Initiative (2007) to 2,240 MW under AB 327 passed October 2013, codified in Public Utilities Code section 769, which will add substantial unanticipated solar resources in the Moorpark sub-area;
- An increase in SCE's energy storage target from 50 MW in D.13-02-015 to 580 MW in D.13-10-040 (October 2013); and
- Establishment by the Commission of explicit LCR values for rooftop solar and energy storage in May 2014 in the 2014 Long-Term Procurement Proceeding (LTPP) that allow precise calculation of the LCR need reduction of additional rooftop solar and energy storage projects in SCE and SDG&E territories that were not quantified in either D.13-02-015 or D.14-03-014.

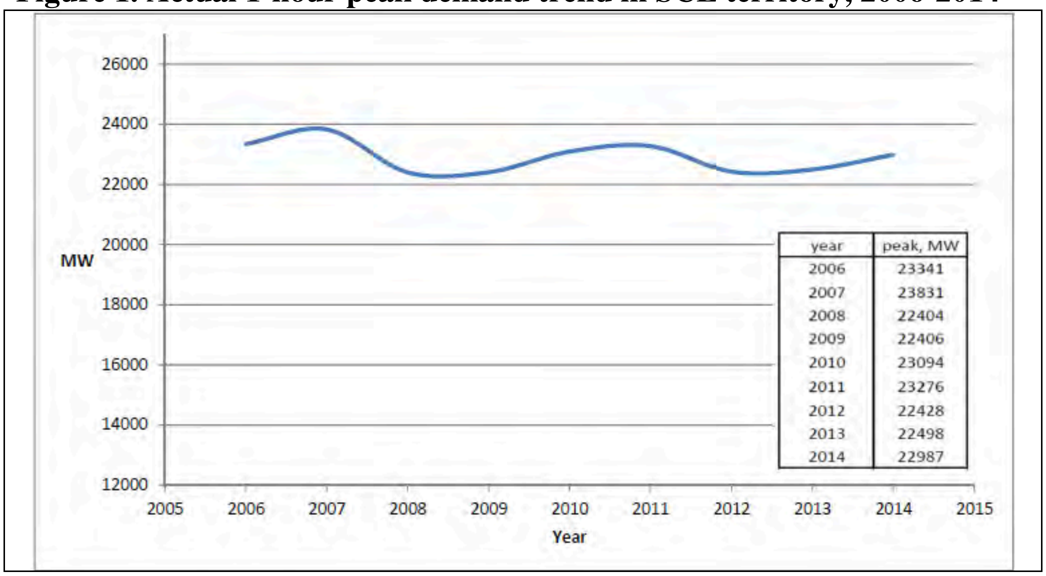
II. The Magnitude of Forecasting Errors in the 2020 SCE Peak Demand Forecasts Relied on by the Commission and CAISO in Projecting 2020 Reliability Need Are Not Reasonable

[6] Ibid, Finding of Fact 42, p. 125.

Q9. Do the 2009 California Energy Commission (CEC) California Electricity Demand (CED) forecast used in CAISO local capacity modeling in Track 1 and the 2011 CED forecast used in Track 4 CAISO modeling erroneously assume a constantly increasing peak demand in SCE territory?

A9. Yes. Actual SCE peak demand has declined since the all-time peak in 2007. Figure 1 showing the actual SCE peak demand trend from 2006 to 2014.

Figure 1. Actual 1-hour peak demand trend in SCE territory, 2006-2014[7,8]



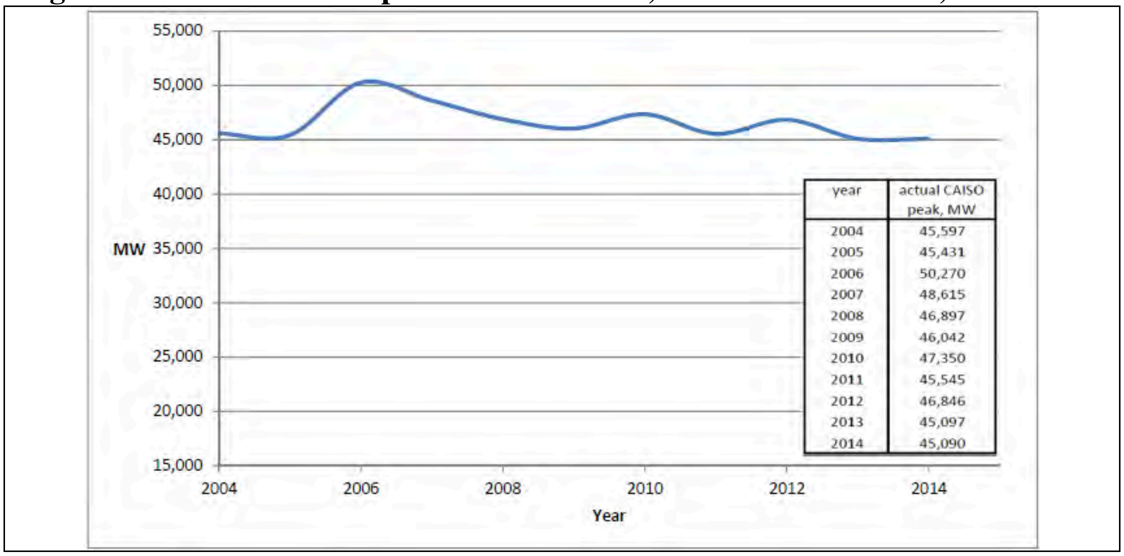
Q10. Is peak load growth happening in the CAISO control area?

A10. No. The peak load trend in the CAISO control area, which includes PG&E, SCE, and SDG&E, is similar to the SCE trend as shown in Figure 2.

[7] Exhibit PE-03, Earthjustice, R.12-03-014 - *Opening Comments of Sierra Club California on ALJ Gamson's Questions from the September 4, 2013 Prehearing Conference*, September 30, 2013, Figure 1, p. 13.

[8] Exhibit PE-04, CAISO OASIS database, September 15, 2014, 5 to 6 pm, "actual" 1-hour loads.

Figure 2. Actual 1-minute peak demand trend, CAISO control area, 2004-2014[9,10]



Q11. Reliability modeling is based on 1-in-10 year peak demand forecasts. Is the difference between the actual declining peak load trend in CAISO and SCE control areas and the 1-in-10 year peak load forecasts coincidental and due to moderate to cool summers?

A11. No, it is not due to an anomalous sequence of moderate to cool summers. The Commission identified 2012 as a 1-in-10 year in SCE territory.[11] Regarding the summer of 2014, CAISO states that, "*Southern California set new demand records that underscore the impact from above normal — hot — temperatures recorded during the summer (of 2014).*"[12] California and SCE are experiencing declining peak loads even while experiencing 1-in-10 year demand events.

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[9] Exhibit PE-05, CAISO, *California ISO Peak Load History 1998 through 2013*, January 2, 2014.
[10] Exhibit PE-06, CAISO news release, *California ISO: challenging 2014 summer but reliability held firm*, October 20, 2014.
[11] Exhibit PE-07, CPUC *Staff Report, Lessons Learned From Summer 2012 Southern California Investor Owned Utilities' Demand Response Programs*, May 1, 2013, p. 31. "September 14, 2012 was considered a hot day (1-in-10 weather year condition), however, SCE still did not dispatch their entire residential Summer Discount Plan participants."
[12] Exhibit PE-06, CAISO news release, *California ISO: challenging 2014 summer but reliability held firm,* October 20, 2014. The new peak demand records were set in SDG&E territory, not SCE territory.

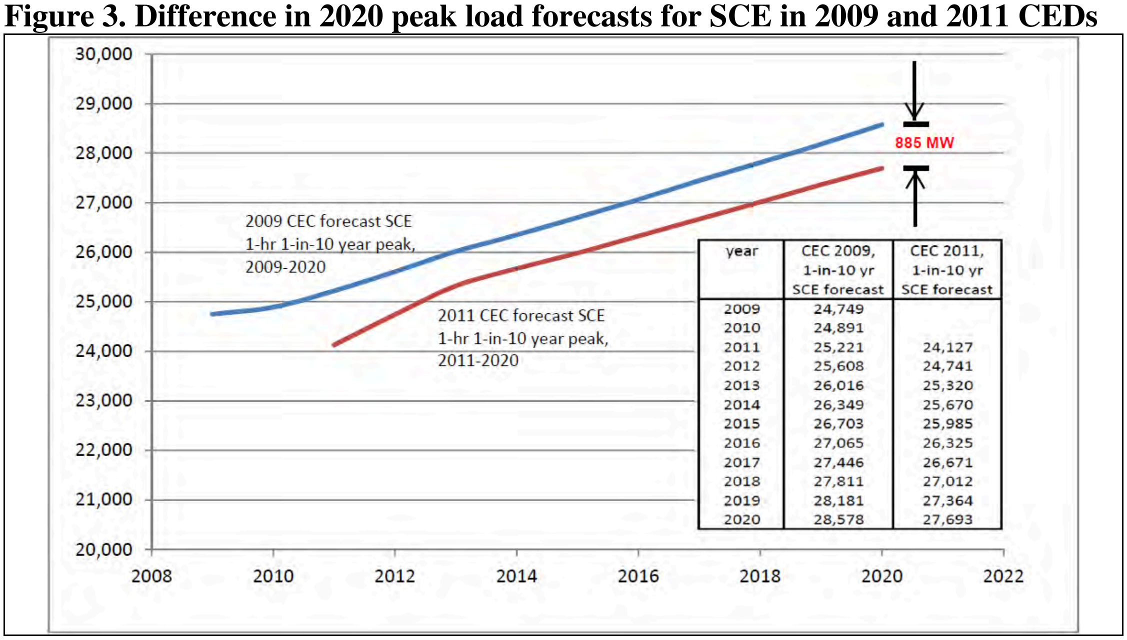
Q12. Is it reasonable for the Commission to assume constantly increasing peak demand given actual declining peak demand trends in CAISO and SCE control areas since D.13-02-15 was issued in February 2013 and over the last decade?

A12. No. Assuming constantly increasing peak demand given actual unchanging or declining peak demand trends is unreasonable and will result in over-procurement if relied upon.

Q13. How does the CEC incorporate the actual unchanging or declining actual peak loads in its subsequent electricity demand forecasts and how does that impact need authorizations based on earlier, higher demand forecasts?

A13. The CEC adjusts the initial year peak forecast downward to reflect actual peak loads in the intervening years since the prior forecast. This is shown in Figure 3. There is a reduction between the 2009 California Energy Demand (CED) forecast and 2011 CED peak demand forecasts for SCE territory in 2020 of 885 MW.[13,14]

Figure 3. Difference in 2020 peak load forecasts for SCE in 2009 and 2011 CEDs



year	CEC 2009, 1-in-10 yr SCE forecast	CEC 2011, 1-in-10 yr SCE forecast
2009	24,749	
2010	24,891	
2011	25,221	24,127
2012	25,608	24,741
2013	26,016	25,320
2014	26,349	25,670
2015	26,703	25,985
2016	27,065	26,325
2017	27,446	26,671
2018	27,811	27,012
2019	28,181	27,364
2020	28,578	27,693

13 Exhibit PE-08, 2009 CED forecast, SCE territory.
14 Exhibit PE-09, 2011 CED forecast.

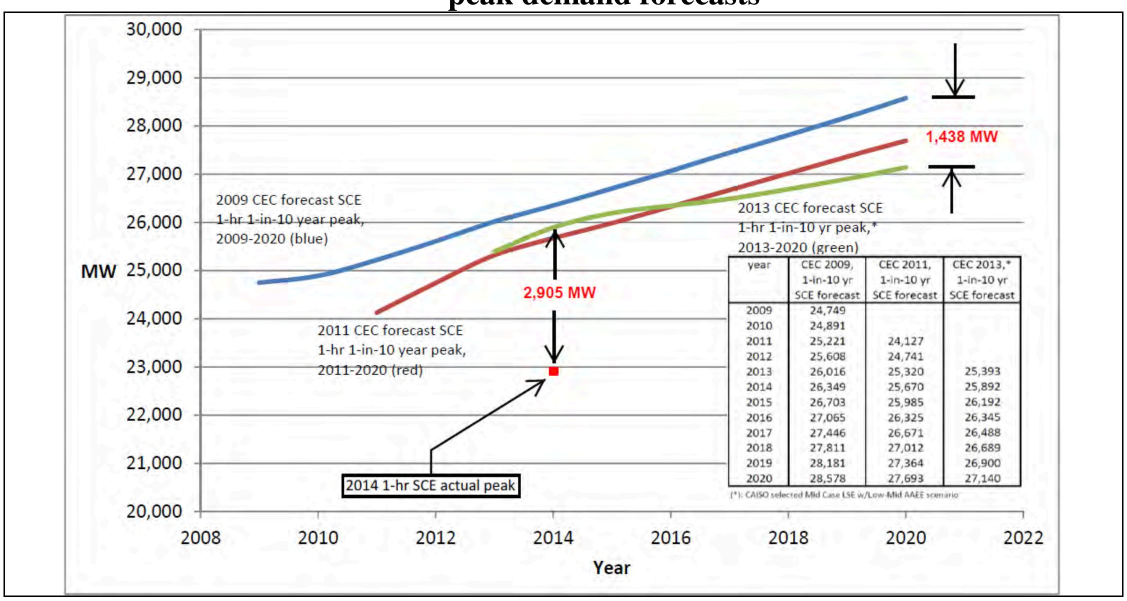
Q14. Was the 2011 CED forecast used as input to the CAISO modeling that served as the basis for the SCE and SDG&E Track 4 procurement authorizations in D.14-03-014?

A14. Yes.

Q15. Has the most recent CEC demand forecast, the 2013 CED forecast, projected even less peak demand in 2020 than the 2011 CED forecast?

A15. Yes. The 2013 CED forecast,[15] specifically the "*Mid-Case Load Serving Entity (LSE) scenario with Mid-Low Additional Achievable Energy Efficiency (AAEE)*" used by CAISO in its revised draft 2014-2015 Transmission Plan,[16] projects a 2020 SCE peak demand that is 1,438 MW less than the 2020 SCE peak demand projected in the 2009 CED forecast. The 2009 CED, 2011 CED, and 2013 CED forecasts for SCE territory through 2020 are shown in Figure 4.

Figure 4. Comparison of 2020 SCE 1-hour 2009 CED, 2011 CED, and 2013 CED peak demand forecasts



year	CEC 2009, 1-in-10 yr SCE forecast	CEC 2011, 1-in-10 yr SCE forecast	CEC 2013,* 1-in-10 yr SCE forecast
2009	24,749		
2010	24,891		
2011	25,221	24,127	
2012	25,608	24,741	
2013	26,016	25,320	25,393
2014	26,349	25,670	25,892
2015	26,703	25,985	26,192
2016	27,065	26,325	26,345
2017	27,446	26,671	26,488
2018	27,811	27,012	26,689
2019	28,181	27,364	26,900
2020	28,578	27,693	27,140

Q16. CAISO states that 2014 was an above normal, hot, summer in Southern California. How does the actual 2014 SCE peak load compare to the

[15] Exhibit PE-10, 2013 CED forecast.
[16] Exhibit PE-11, CAISO, *CAISO 2014-2015 Transmission Plan – Revised Draft*, March 19, 2015, p. 43.

projected 1-hour, 1-in-10 year 2014 SCE peak load in the 2013 CED forecast?

A16. The actual SCE 1-hour peak load in 2014 was 22,987 MW on September 15, 2014 between 5 and 6 pm. The 2013 CED forecast 1-in-10 year peak load for SCE in 2014 was 25,892 MW. This forecast SCE 2014 peak was 2,905 MW higher than the actual peak.

Q17. Does a qualitative statement by CAISO that 2014 was an above normal, hot summer in Southern California equate to identifying the summer of 2014 as a 1-in-5 year or 1-in-10 year summer?

A17. No. The term "above normal – hot" likely indicates at least a 1-in-5 year summer weather event and potentially a 1-in-10 year event.

Q18. What is the relationship between a typical 1-in-2 year peak demand, a 1-in-5 year peak demand, and a 1-in-10 peak demand?

A18. A 1-in-5 year forecast is 1.068 greater than a 1-in-2 year forecast. A 1-in-10 year forecast is 1.088 greater than a 1-in-2 year forecast.[17] Therefore if the 2014 1-hour peak SCE demand of 22,987 MW was a 1-in-5 year event, the 1-in-10 year forecast 2014 1-hour peak SCE demand would be 23,417 MW.[18] This forecast 1-in10 year 1-hour SCE peak load, derived from the actual 2014 1-hour peak SCE demand, is 2,475 MW less than the forecast 2014 1-hour SCE peak load of 25,892 MW in the 2013 CED "*Mid-Case LSE scenario with Mid-Low AAEE*" used by CAISO in its revised draft 2014-2015 Transmission Plan modeling.[19]

Q19. If the 2013 CED 1-in-10 year SCE peak demand forecast is 2,475 MW higher in 2014 than it should be based on the actual 2014 SCE peak demand, how does that affect the Moorpark sub-area authorization in D.13-02-015?

[17] Exhibit PE-08.
[18] (1-in-5 year actual peak load)(1.088/1.068) = 1-in-10 year peak load. 22,987 MW × (1.088/1.068) = 23,417 MW.
[19] Exhibit PE-11, CAISO, *CAISO 2014-2015 Transmission Plan – Revised Draft*, March 19, 2015, p. 43.

A19. Every year in the forecast, without addressing whether the year-to-year load growth in the forecast is reasonable, is at least 2,475 MW higher than it should be for SCE territory based on the actual 2014 SCE 1-hour peak load being at least a 1-in-5 year event. A portion of this erroneously 2014 high base year SCE forecast is attributable to load in the Moorpark sub-area.

Q20. The Moorpark sub-area is a sub-area of the Big Creek/Ventura LCR. What percentage of SCE peak load does the Big Creek/Ventura LCR represent?

A20. The Big Creek/Ventura LCR represented about 17.7 percent of SCE's 2020 1-in-10 year peak in the 2009 CED forecast used in CAISO modeling used in the 2012 LTPP Track 1 proceeding that resulted in D.13-02-015.[20]

Q21. If the Big Creek/Ventura LCR area is 17.7 percent of SCE's peak load, how does the base year forecasting error affect the Moorpark sub-area need determination in D.13-02-015?

A21. The base year forecasting error for the Big Creek/Ventura LCR area would be: $0.177 \times 2{,}475$ MW = 438 MW. This is substantially greater than the 215 MW to 290 MW Moorpark sub-area need authorization in D.13-02-015, and would eliminate the need authorization.

Q22. Is the 2013 CED base year forecasting error also present in the 2009 CED and 2011 CED forecasts for SCE territory?

A22. Yes. See Figure 4. The error is more pronounced in the 2009 CED forecast, which was used in the CAISO modeling that served as the basis for the Track 1 authorization in D.13-02-015 for 215 MW to 290 MW in the Moorpark sub-area.

Q23. What is the difference between the 2009 CED forecast of 2014 1-hour peak load in SCE territory and the 1-in-10 year SCE forecast based on the actual 2014 1-hour SCE peak load?

A23. The difference is 3,362 MW for SCE territory.

[20] Exhibit PE-12, CEC, *Form 1.5d; California Energy Demand 2010-2020 Staff Revised Forecast, 1-in-10 Net Electricity Peak Demand by Agency and Balancing Authority*, November 2009. 5,186 MW ÷ 29,240 MW = 0.177 (17.7 percent).

Q24. What is the reduction in 2020 forecast SCE peak load between the 2009 CED forecast and the 2013 CED forecast?

A24. The reduction in 2020 SCE peak load is 1,438 MW as shown in Figure 4.

Q25. What is the reduction in the forecast 2020 peak load in the Big Creek/Ventura LCR?

A25. The Big Creek/Ventura LCR is 17.7 percent of SCE's peak load. Therefore, the reduction in 2020 peak load in the Big Creek/Ventura LCR using the more current 2013 CED forecast is: 0.177 x 1,438 MW = 255 MW.

Q26. What is the total reduction in 2020 Big Creek/Ventura LCR 1-hour peak demand when a forecast that is calibrated to actual 2014 peak demand is used and the most current 2013 CED 2020 SCE peak demand forecast is also used?

A26. The Big Creek/Ventura 2020 reliability need would decline by: 438 MW + 255 MW = 693 MW.

Q27. What percentage of the Big Creek/Ventura LCR peak load does the Moorpark sub-area represent?

A27. Unknown. SCE has indicated it does not have a readily available peak load forecast for the Moorpark sub-area.[21]

Q28. Does the CED 2013 1-in-10 year peak load forecast project any peak load growth in the Big Creek/Ventura LCR?

Q28. No. The "*Final California Energy Demand Forecast, 2014 - 2024, Mid Demand Baseline, Mid AAEE Savings*," adopted jointly be the Commission, CEC, and CAISO as the representative peak load forecast in the 2013 IEPR,[22] shows no growth in 1-in-10 year peak load for the Big Creek/Ventura LCR as shown in Figure 5.

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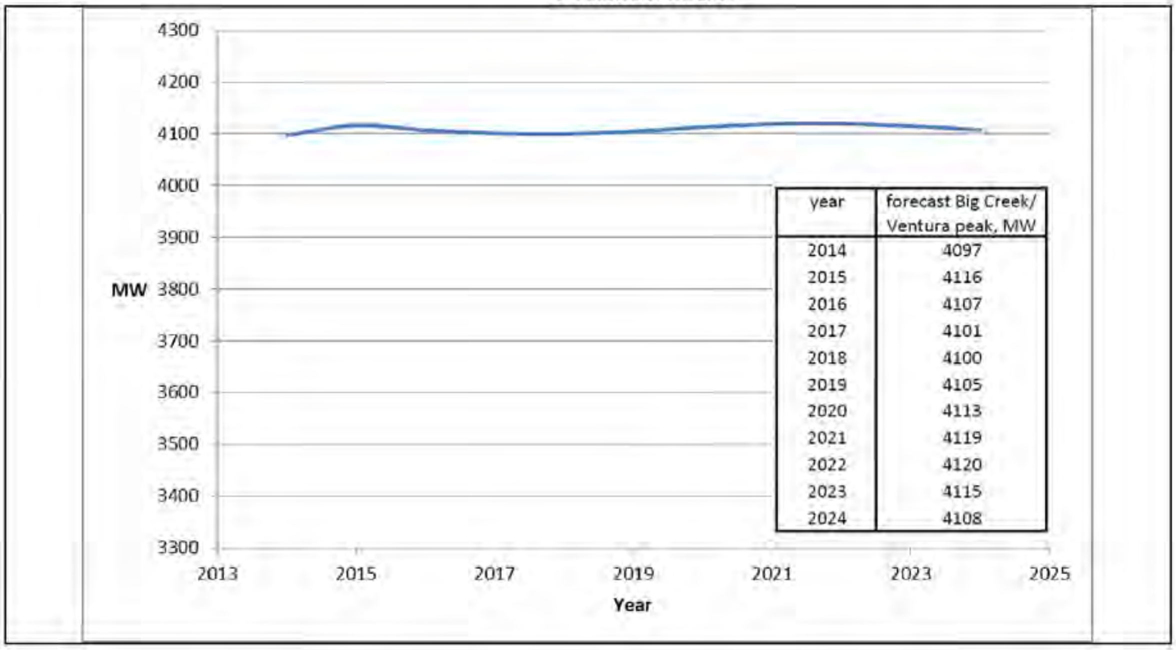
[21] Exhibit PE-13, April 8, 2015 e-mail, Tristan Reyes Close/SCE to April Rose Sommer/CBD.

[22] Exhibit PE-11, CAISO, *CAISO 2014-2015 Transmission Plan – Revised Draft*, March 19, 2015, p. 43. "During 2013, the CEC, CPUC and ISO engaged in collaborative discussion on how to consistently account for reduced energy demand from energy efficiency in these planning and procurement processes. To that end, the 2013 Integrated Energy Policy Report (IEPR) final report, published on January 23, 2014, recommends using the Mid Additional Achievable Energy Efficiency (AAEE) scenario for system-wide and flexibility studies for the CPUC 2014 LTPP and ISO 2014-15 TPP cycles."

Figure 5. 2013 CED 2014-2024 peak load growth forecast for Big Creek/ Ventura LCR[23]



Q29. Is it reasonable for the Commission to approve A.14-11-016, specifically the 262 MW gas-fired generation contract included in A.14.11-016, when the underlying 2020 load forecast used in Track 1 modeling overstates the Big Creek/Ventura LCR peak demand by nearly 700 MW and when the Commission is now projecting no load growth in the Big Creek/Ventura LCR through 2024?

A29. No.

Q30. Are the CEC's CED forecasts developed in evidentiary proceedings similar to Commission proceedings?

A30. No. There are no evidentiary proceedings. The forecasts are developed using a workshop procedure.

Q31. Are the CED forecasts reviewed in Commission long-term procurement planning (LTPP) proceedings, such as the 2012 LTPP Track 1 and Track 4 proceedings?

[23] Exhibit PE-14, 2013 CED, Final California Energy Demand Forecast, 2014 - 2024, Mid Demand Baseline, Mid AAEE Savings (Big Creek/Ventura Subtotal).

A31. No. The Commission has the authority to review the reasonableness of CEC demand forecasts used in LCR need modeling but to date has chosen not to exercise that authority.

III. The Substantially Increased SCE Rooftop Solar Target Established in AB 327 in October 2013 Reduces Big Creek/Ventura LCR Reliability Need by an Additional 246 MW by 2016, and by an Additional 116 MW in the 2017-2021 Period

Q32. What was the SCE rooftop solar target at the time D.13-02-015 was issued in February 2013?

A32. At the time D.13-02-015 was issued, California's investor-owned utilities (IOUs) are in the process of meeting the original California Solar Initiative (CSI) solar PV targets.[24] The IOUs were to have 1,940 MW online by December 2016, and appear to have met the CSI targets in late 2014.[25,26] This solar capacity is installed on the customer side of the electric meter, on rooftops and parking lots primarily, and is known as "net-metered" or "behind the meter" solar. The approximate SCE share of the 1,940 MW IOU target is about 850 MW.[27]

Q33. Do the 2009 CED and 2011 CED forecasts assume a steep decline in rooftop solar additions after the end of the CSI program?

A33. Yes. Even the most recent CEC forecast, the 2013 CED, assumes peak demand behind-the-meter solar capacity additions of 39 MW in 2014, 15 MW

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

[25] Exhibit PE-15, B. Del Chiaro, CALSEIA e-mail to B. Powers, February 17, 2015, regarding capacity of rooftop solar installed in 2014. "At least a 25 – 30 percent increase over 2013 (when ~1,000 MW_{ac} of net-metered solar installed), final numbers still pending."

[26] Exhibit PE-16, Renewable Energy World, *California Blows the Lid off Solar Records Installing 1GW of Rooftop Solar in 2013*, January 23, 2014.

[27] D.13-10-040, Table 2, p. 15. SCE allocation of energy storage among the three IOUs is 44 percent. This same percentage is used to estimate approximate SCE allocation of the IOU's 1,940 MW allocation of rooftop solar. SCE allocation rooftop solar: 0.44 × 1,940 MW = 854 MW. LA Basin share of SCE load is 77 percent. Therefore, Big Creek/Ventura allocation of SCE rooftop solar: 0.177 × 854 MW = 152 MW.

in 2015, and 28 MW in 2016.[28] The CEC forecasts a 5-year SCE average rooftop solar capacity addition, from 2017 through 2021, of 23 MW per year.[29] The 2013 CED forecast, finalized in January 2014, does not take into account the much higher AB 327 net-metering solar targets signed into law in October 2013.[30]

Q34. How much did the rooftop solar target of the IOUs increase with the passage of AB 327 in October 2013?

A34. The passage of AB 327 in October 2013 enacted Public Utilities Code Section 2827(c)(4)(B) and established minimum statutory net-metering rooftop solar targets to be met by the IOUs no later than mid-2017. AB 327 increased the minimum net-metering cap of the IOUs to 5,256 MW.[31]

Q35. By how much did the SCE and Big Creek/Ventura LCR rooftop solar target increase as a result of the passage of AB 327?

A35. The net-metering cap in SCE territory increased from approximately 850 MW to 2,240 MW.[32] This is an additional SCE rooftop solar capacity of 1,390 MW. Approximately 246 MW of this additional solar capacity would be located in the Big Creek/Ventura LCR, assuming solar distribution proportionate to load throughout SCE territory.[33] About 116 MW of this additional capacity will be available to meet peak load.[34] SCE is required by Section 2827(c)(4)(C) to report on a monthly basis its progress in meeting the

[28] CEC, *California Energy Demand 2014-2024 Final Forecast Mid-Case Final Baseline Demand Forecast Forms*, November 19, 2013, SCE Mid.xls, SCE Form 1.4-Mid, "PV" column: http://www.energy.ca.gov/2013_energypolicy/documents/demand-forecast/mid_case/
[29] Ibid.
[30] Assembly Bill No. 327 (Cal. 2013).
[31] Public Utilities Code Section 2827(c)(4)(B): http://www.leginfo.ca.gov/cgi-bin/displaycode?section=puc&group=02001-03000&file=2821-2829. SDG&E net-metering target = 607 MW. SCE net-metering target = 2,240 MW. PG&E net-metering target = 2,409 MW. Total of the three IOUs = 5,256 MW.
[32] The SCE share of the energy storage targets in D.13-10-040 is 580 MW of 1,325 MW, or 44 percent. Applying this same percentage to the 1,940 MW IOU net-metered solar target gives a SCE share of 1,940 MW × 0.44 = 854 MW.
[33] Big Creek/Ventura LCR share of total: 0.177 × 1,390 MW = 246 MW.
[34] CPUC Rulemaking R.13-12-010, *Assigned Commissioner's Ruling Technical Updates to Planning Assumptions and Scenarios for Use in the 2014 Long Term Procurement Plan and 2014-15 CAISO TPP*, May 14, 2014, Tab le 1, p. 13. Rooftop solar output at peak demand = 0.47. Portion of the LA Basin additional solar capacity available at peak = 0.47 × 246 MW = 116 MW.

new minimum solar PV target by mid-2017. The current behind-the-meter rooftop solar installation rate in SCE territory is 30 – 35 MW per month.[35] Proportionately this would be a rooftop solar installation rate of 5 – 6 MW per month in the Big Creek/Ventura LCR.[36]

Q36. Are the IOUs on track to meet the much higher AB 327 rooftop solar targets?

A36. Yes. 1,000 MW of rooftop and parking lot solar capacity was added in California in 2013.[37] Approximately 1,300 MW was added in 2014.[38] At current installation rates, with about 2,000 MW of new capacity need to reach the AB 327 net-metering target of 5,256 MW, the goal will be reached by the end of 2016.

Q37. How much additional rooftop solar will be added in the Big Creek/ Ventura LCR in the 2017 to 2021 period?

A37. Maintaining the actual 1,300 MW self-generation solar installation rate from 2017 through 2021 would add about 6,500 MW of new solar capacity in the state, of which at least about 4,350 MW would be in IOU territories regulated by the Commission.[39] Approximately 339 MW of this capacity would be located in the Big Creek/Ventura LCR.[40] Of this 339 MW, about 159 MW would qualify as reliable peak Big Creek/Ventura LCR capacity by 2021.[41]

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[35] Exhibit PE-17, SCE Advice Letters 3144-E, 3159-E, 3175-E, SCE monthly advice on progress in meeting net-metering targets per D.14-03-041, December 2014 – February 2015.

[36] 0.177 × (30 – 35 MW per month) = 5 – 6 MW per month.

[37] Exhibit PE-16, Renewable Energy World, *California Blows the Lid off Solar Records Installing 1GW of Rooftop Solar in 2013*, January 23, 2014.

[38] Exhibit PE-15, B. Del Chiaro, CALSEIA e-mail to B. Powers, February 17, 2015, regarding capacity of rooftop solar installed in 2014. “At least a 25 – 30 percent increase over 2013 (when ~1,000 MW_{ac} of net-metered solar installed), final numbers still pending.” 1,000 MW + (0.30 × 1,000 MW) = 1,300 MW.

[39] Investor-owned utilities, which include SCE, PG&E, and SDG&E, serve approximately two-thirds of California statewide electric demand. Therefore, 6,500 MW × 0.67 = 4,355 MW.

[40] 0.44 × 0.177 × 4,355 MW = 339 MW.

[41] PE-18, R.13-12-010, *Assigned Commissioner’s Ruling Technical Updates to Planning Assumptions and Scenarios for Use in the 2014 Long Term Procurement Plan and 2014-15 CAISO TPP*, May 14, 2014, Tab le 1, p. 13. SCE rooftop solar output at peak demand = 0.47. Therefore, reliable output at peak of rooftop solar added to LA Basin in 2017-2020 timeframe is: 0.47 × 339 MW = 159 MW.

Q38. How likely is it that the accelerated rooftop solar will be sustained after 2016?

A38. This scenario is very likely to occur unless the Commission authorizes self-generation solar contracts at rates that are substantially below what the Commission has already determined the self-generation solar is worth. This will not happen if Commission follows state law:[42]

> In developing the standard contract or tariff, the commission shall do all of the following:
>
> (1) Ensure that the standard contract or tariff made available to eligible customer-generators ensures that customer-sited renewable distributed generation continues to grow sustainably and include specific alternatives designed for growth among residential customers in disadvantaged communities.

Customer-sited renewable distributed generation cannot continue to grow sustainably unless the contract rate makes it economic to do so, and state law requires the CPUC to establish contract terms that result in growth in the rate of customer-side solar installations.

Q39. Has the Commission determined that the avoided cost of rooftop solar will be about $0.15/kWh in 2017?

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[42] Public Utilities Code Section 2827.1(b): http://www.leginfo.ca.gov/cgi-bin/displaycode?section=puc&group=02001-03000&file=2821-2829. "Notwithstanding any other law, the commission shall develop a standard contract or tariff, which may include net energy metering, for eligible customer-generators with a renewable electrical generation facility that is a customer of a large electrical corporation no later than December 31, 2015. The commission may develop the standard contract or tariff prior to December 31, 2015, and may require a large electrical corporation that has reached the net energy metering program limit of subparagraph (B) of paragraph (4) of subdivision (c) of Section 2827 to offer the standard contract or tariff to eligible customer-generators. A large electrical corporation shall offer the standard contract or tariff to an eligible customer-generator beginning July 1, 2017, or prior to that date if ordered to do so by the commission because it has reached the net energy metering program limit of subparagraph (B) of paragraph (4) of subdivision (c) of Section 2827. The commission may revise the standard contract or tariff as appropriate to achieve the objectives of this section. In developing the standard contract or tariff, the commission shall do all of the following:
(1) Ensure that the standard contract or tariff made available to eligible customer-generators ensures that customer-sited renewable distributed generation continues to grow sustainably and include specific alternatives designed for growth among residential customers in disadvantaged communities."

A39. Yes. The Commission determined the "avoided cost" of self-generated rooftop and parking lot solar is approximately $0.12/kWh in 2015.[43] This avoided cost is projected to rise to $0.15/kWh by 2017 and stay relatively constant at this value through 2020.[44] This is the cost that the IOUs would bear to replace the self-generated solar power if it were not being produced.

Q40. What is the price the IOUs will pay for rooftop solar after net-metering ends?

A40. The CPUC must set rates for self-generated solar power to supersede the current net metering program when it expires.[45] It is reasonable to assume that the rate paid for self-generated solar power in a post net-metering regulatory environment will be in the range of the avoided cost that the Commission has already calculated for self-generated solar power, or about $0.15/kWh beginning in 2017.

Q41. Is the production cost of commercial and residential rooftop solar projected to be below $0.15/kWh in 2017?

A41. Yes. The 2016 production cost of residential rooftop solar, commercial rooftop solar, based on DOE projections of best-in-class and mid-range capital, are provided in Table 3.[46] These production costs are provided with the current investment tax credit (ITC) of 30 percent for commercial and residential projects and the post-2016 ITC of 10 percent for commercial projects and zero percent for residential projects. In all scenarios the post-2016 production cost is less than $0.15/kWh.

Table 3. Residential and commercial solar production cost ranges, pre- and post-2016

ITC	Residential rooftop production cost range [$/kWh]	Commercial rooftop production cost range [$/kWh]

[43] Exhibit PE-19, California Public Utilities Commission, *California Net Metering Ratepayer Impacts Evaluation*, October 28, 2013, Figure 14, p. 57.
[44] Ibid, Figure 14, p. 57.
[45] Public Utilities Code Section 2827.1(b).
[46] Exhibit PE-20, Powers Engineering *Powers Engineering Comment Letter on Draft DRECP NEPA/CEQA*, February 23, 2015.

30% (thru 2016)	0.072 – 0.101	0.050 – 0.072
10% (post 2016)	--	0.059 – 0.081
0% (post 2016)	0.097 – 0.137	--

Q42. Isn't SCE proposed to meet LCR need in A.14-11-012 by contracting by behind-the-meter rooftop solar at locations in the Moorpark sub-area that are not yet determined?

A42. Yes. SCE will require the seller to install PV at various commercial/industrial sites that have yet to be identified, in order to achieve energy savings. The installations will serve part of the customer's energy needs. From SCE's perspective, the power to the customer provided by the solar installation will result in customer load drop. [47]

Q43. Isn't the form of the distributed solar that SCE seeks to enter into contracts for in A.14-11-016, functionally the same as any behind-the-meter rooftop solar installation?

A43. Yes.

Q44. Therefore, shouldn't the approximately 275 MW of additional behind-the-meter rooftop solar capacity that will be available at times of peak demand in the Big Creek/Ventura LCR in 2021 that was not anticipated at the time D.13-02-015 was issued be counted toward meeting the 2021 Big Creek/Ventura LCR need?

A44. Yes.

IV. Recent Action by the Commission Defining the Reliability of Energy Storage Is a Changed Circumstances that Reduces Big Creek/Ventura Reliability Need by about 70 MW by 2024

Q45. Did D.13-02-15 assume any energy storage capacity would be located in the Big Creek/Ventura LCR?

[47] A.14-11-016, *SCE-1: Testimony of Southern California Edison Company on the Results of its 2013 Local Capacity Requirements Request for Offers (LCR RFO) for the Moorpark Sub-Area*, November 26, 2014, p. 53.

A45. No.

Q46. What is the SCE energy storage target established in D.13-10-040?

A46. 580 MW.

Q47. What did D.14-03-014 state regarding the reliability of energy storage to meet LCR need?

A47. "The incipient nature of energy storage resources, uncertainty about location and effectiveness, and unknowns concerning timing provide insufficient information at this time to assess how and to what extent energy storage resources can reduce LCR needs in the future."[48]

Q48. Does this mean that the Commission assigned no specific reliability value to energy storage in D.14-03-014?

A48. That is correct.

Q49. How much of this 580 MW of SCE energy storage capacity will be located in the Big Creek/Ventura LCR?

A49. 103 MW,[49] assuming the distribution of energy storage is proportionate to demand in the Big Creek/Ventura LCR.

Q50. How much of this 103 MW of energy storage in the Big Creek/Ventura LCR is considered reliable peak capacity by the Commission now?

A50. About 71 MW. The 2014 LTPP final list of assumptions assumes all transmission-level storage is reliably available at peak, one half of distribution-level storage is reliably available at peak, and none of the distributed storage is available at peak.[50]

Q51. Is energy storage a better fit for meeting both reliability need and renewable energy integration in the Big Creek/Ventura LCR than gas-fired generation?

A51. Yes. Shell Energy North America LLC enumerated the disadvantages of low capacity factor gas-fired generation for renewable energy integration, and the

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[48] D.14-03-014, Finding of Fact 51, p. 129.
[49] 0.177 x 580 MW = 103 MW.
[50] Exhibit PE-18, R.13-10-013, *Assigned Commissioner's Ruling Technical Updates to Planning Assumptions And Scenarios for Use in the 2014 Long Term Procurement Plan And 2014-15 CAISO TPP*, May 14, 2014, p. 18. 0.177 × [(1.0 × 310 MW) + (0.5 × 185 MW) + (0.0 × 85 MW)] = 71.3 MW.

advantages of energy storage in the same application, in the A.14-07-009 proceeding:[51]

> In order to integrate new renewable energy supplies, renewable resources must be balanced by resources that can provide frequency response and VAR support. Peaking facilities generally have a low capacity factor (are only on-line for limited time periods), resulting in very limited ability to provide VAR support. Peaking facilities also do not provide the frequency response that is needed to stabilize the grid upon the loss of a generation unit or transmission line. In addition, due to their expected low capacity factor, peakers do not provide consistent system inertia, which is the ability of a power system to support imported energy. The characteristics of peaking facilities raise serious questions about whether a PPTA for 600 MW of peaking capacity is consistent with the need to integrate increased renewable supplies into SDG&E' s local reliability area. . . In light of (CAISO) Mr. Sparks' expressed concern about voltage stability and "degradation of deliverability of renewable generation in the Imperial Valley," (Ex. 4 at p. 8), it is questionable whether peaking units with a low capacity factor are the best resources to meet the local reliability need created by the loss of SONGS. . . Other resources, including pumped hydro storage, provide system inertia, VAR support and frequency response, all of which are necessary to integrate renewables and provide system stability. . . Alternative resources may have operational characteristics that are more consistent with the State's loading order and that more efficiently integrate the delivery of renewable energy into the San Diego sub-area, but these resources may be pre-empted by the Commission's approval of the Carlsbad Energy Center PPTA.

Q52. Is the amount of 0.5 MW of energy storage that SCE proposes in A.14-11-016 credible in light of the highly probable location of approximately 71 MW of energy storage authorized in D.13-10-040 capable of meeting LCR need in the Big Creek/Ventura LCR?

A52. No. At a minimum, approximately 71 MW of energy storage should be assumed in the Big Creek/Ventura LCR and the need authorization for the Moorpark sub-area adjusted downward to reflect this amount of energy storage.

[51] Exhibit PE-21, A.14-07-009, Opening Brief of Shell Energy North America (US), L.P., December 10, 2014, pp.7-8, p.10, p.16.

V. D.14-03-014 Authorized 433 MW of Load Shedding in SCE Territory, Yet None Is Authorized in D.13-02-015 for the Moorpark Sub-Area

Q53. Doesn't D.14-03-014 authorize load shedding in SCE territory?

A53. Yes.[52] 433 MW of load shedding are authorized in SCE territory.

Q54. Doesn't D.14-03-014 explicitly state that load shedding is assumed to occur to reduce LCR need?

Q54. Yes. Conclusion of Law 12 states:[53]

> 12. It is reasonable to subtract 588 MW from the ISO's forecasted LCR need to account for resources that will not be procured at this time to fully avoid the possibility of load-shedding in San Diego as a result of the identified N-1-1 contingency.

Q55. Why is load shedding assumed to occur in SCE territory to partially address a N-1-1 Category C contingency in D.14-03-014 but not assumed to occur to address a Category D contingency in D.13-02-015 in the Moorpark sub-area?

A55. No explanation is offered by the Commission in either D.13-02-015 or D.14-03-014 to explain the authorization by the Commission in D.14-03-014 of load shedding to address a Category C contingency impacting the LA Basin while no load shedding is even considered in D.13-02-015 to address a Category D contingency in the Moorpark sub-area.

VI. Commission Over-Reliance on CAISO for Moorpark Sub-Area Reliability Modeling, and Assessment of the Reliability Value of Preferred Resources, Is Not Reasonable

Q56. What is the CAISO?

A56. CAISO is a private non-profit corporation. It was formed in the 1990s as a component of electricity deregulation in California. The purpose of CAISO is

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[52] D.14-03-014, p. 79. "We have already determined that it is reasonable to defer procurement of at least 588 MW of additional resources (433 MW in SCE territory) that otherwise would be required to meet N-1-1 requirements and avoid load shedding." Therefore, the amount of load shedding authorized in D.14-03-014 for SDG&E territory: 588 MW – 433 MW = 150 MW.

[53] D.14-03-014, Conclusion of Law 12, p.

to assure grid reliability. However, the long-term resource planning function was returned to the California investor-owned utilities in 2003 following the failure of deregulation.[54]

Q57. Is the function of the Commission different than that of CAISO?

A57. Yes. The Commission recognized the difference in the functions of CAISO and the Commission in the March 6, 2015 proposed decision denying the 600 MW Carlsbad Energy Center:[55]

> D.13-03-029 (approval of 300 MW Pio Pico Energy Center) acknowledged that the OTC's modeling assumptions (conducted by CAISO) reflected the CAISO's statutory responsibility to consider, for transmission planning purposes, only those resources that are certain to materialize, but emphasized that the Commission's statutory responsibility requires us to ensure just and reasonable rates.

Q58. Does California law require that unmet need be met with preferred, non-gas-fired generation resources?

A58. Yes. D.13-02-015 summarizes California law on the issue of how unmet electricity need is to be met:[56]

> Section 454.5(b)(9)(C) states that utilities must first meet their "unmet resource needs through all available energy efficiency and demand reduction resources that are cost-effective, reliable and feasible." Consistent with this code section, the Commission has held that all utility procurement must be consistent with the Commission's established Loading Order, or prioritization. The Loading Order, first set forth in the Commission's 2003 Energy Action Plan, was presented in the Energy Action Plan II adopted by this Commission and the California Energy Commission (CEC) in October 2005. The Loading Order, which has been reiterated in multiple forums (including D.12-01-033 in the predecessor to this docket), requires the utilities to procure resources in a specific order:
>
> "The 'Loading Order' established that the state, in meeting its energy needs, would invest first in energy efficiency and

[54] CPUC LTPP webpage. http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/

[55] Exhibit PE-22, CPUC A.14-07-009, *Decision Denying Without Prejudice San Diego Gas & Electric Company's Application for Authority to Enter into Purchase Power Tolling Agreement with Carlsbad Energy Center, LLC*, March 6, 2015, p. 14.

[56] D.13-02-015, p. 10.

demand-side resources, followed by renewable resources, and only then in clean conventional electricity supply."

Q59. Did the Commission anticipate filling much of the Moorpark sub-area local reliability need identified in CAISO modeling with preferred resources?

A59. Yes. The Commission stated in D.13-02-015 that:

> "We anticipate that much of the additional LCR need currently forecast by the California Independent System Operator can be filled by preferred resources, either through procurement of capacity or reduction in demand. Preferred resources include energy efficiency, demand response, and distributed generation including combined heat and power."[57] . . . "In D.07-12-052 at 12, the Commission stated that once demand response and energy efficiency targets are reached, "the utility is to procure renewable generation to the fullest extent possible." The obligation to procure resources according to the Loading Order is ongoing. (D.12-01-033 at 19.) In D.12-01-033 at 21, the Commission recognized that procuring additional preferred resources is more difficult than "just signing up for more conventional fossil fuel generation," but consistency with the Loading Order and advancing California's policy of fossil fuel reduction demand strict compliance with the loading order." [58]

Q60. Is SCE's assertion in its January 22, 2015 response to protests that it accepted all conforming bids that it received for preferred resources credible?

A60. This assertion is credible only in the context of SCE contract terms that were so burdensome that few conforming bids were received for preferred resources. As described in A.14-11-016, SCE offered contracts for 6 MW of energy efficiency and 0 MW of demand response. The 2020 peak load forecast for the Big Creek/Ventura LCR (SCE cannot provide the 2020 peak demand for the Moorpark sub-area), per the 2009 CED forecast, is 5,186 MW. It is not credible that a contracting procedure consistent with California that would be designed to level the playing field for preferred resources would

[57] D.13-02-015, pp. 2-3.
[58] Ibid, p. 11.

have produced an insignificant amount of bids for energy efficiency and demand response, the two resources at the top of the loading order.

Q61. Are sufficient preferred resources available to meet the Moorpark sub-area need authorization in D.13-02-015 if SCE RFO contract terms for preferred resources allow these resources to compete effectively against gas-fired generation?

A.61. Yes. As an example, the Southern California Regional Energy Network has identified 200 MW of public and private preferred resources projects in Ventura County capable of addressing the Moorpark sub-area need authorization in D.13-02-015.[59]

Q62. Given the adequate availability of preferred resources to meet the Moorpark sub-area need authorization in D.13-02-015, wouldn't a preferred resources pilot project similar to SCE's 300 MW pilot project in southern Orange County be the contracting pathway most consistent with California law for meeting the need?

A62. Yes. The purpose of the Orange County pilot project is to demonstrate that preferred resources can fully displace gas-fired generation. The target date for this determination is 2017. Future need in the Moorpark sub-area should be met with preferred resources, consistent with California law. SCE stated in its Track 1 testimony that there was no near-term need for new LCR capacity in the Moorpark sub-area for new capacity.[60] Therefore, given the quantities of additional unanticipated (at the time D.13-02-015 was issued) preferred resources that will be added to the Big Creek/Ventura LCR over the next several years and the relatively near-term 2017 determination that will be made by SCE regarding the success of the 300 MW Orange County preferred resources pilot project for displacing gas-fired generation, it would be prudent to defer any additional procurement authorizations in the Moorpark sub-area

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[59] Exhibit PE-23, County of Los Angeles Internal Services Department, *Letter of Support from the Southern California Regional Energy Network for the Utilization of Preferred Resources in the Ventura County Local Capacity Requirements Region*, April 5, 2015.
[60] D.13-02-015, pp. 68-69.

until the results SCE's 300 MW Orange County preferred resources pilot project are available.[61]

Q63. Is it reasonable for the Commission to largely accept CAISO's rejection of preferred resources to meet reliability need as described in D.13-02-15?

A63. No. It is contrary to California law. CAISO has demonstrated an institutional rejection of preferred resources to meet reliability needs, as summarized in D.13-02-15 citing to the testimony of CAISO's Southern California transmission planning manager Robert Sparks:[62]

> No capacity from demand response was included in any ISO analysis because the ISO "does not believe that demand response can be relied upon to address local capacity needs, unless the demand response can provide equivalent characteristics and response to that of a dispatchable generator." The ISO claims "demand response does not have these characteristics at this time."
>
> Nor does the ISO include any demand reduction for uncommitted energy efficiency or uncommitted combined heat and power (CHP) in its forecasts.

Q64. Is the CAISO reluctance to meet LCR need with demand response resources reflected in burdensome terms placed on demand response providers that submitted bids, or considered submitting bids, into SCE's 2013 RFO for resources in the Moorpark sub-area to meet the SCE need authorization identified in D.13-02-015?

A64. Yes. The EnerNOC, Inc. January 12, 2015 response to SCE Application A.14-11-016 succinctly summarizes how demand response resources were marginalized by CAISO and SCE in the Moorpark sub-area RFO process:[63]

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[61] Exhibit PE-24, SCE brochure, *Preferred Resources Pilot - Providing Reliable Power from Clean Resources*, June 2014.
[62] Ibid, pp. 16-17.
[63] Exhibit PE-25, EnerNOC, Inc., *Response of EnerNOC, Inc. - Application of Southern California Edison Company (U338E) for Approval of the Results of Its 2013 Local Capacity Requirements Request for Offers for the Moorpark Sub-Area*. January 12, 2015, pp. 3-4.

1. The resource requirements for resource adequacy eligibility were developed through private consultations between SCE and the California Independent System Operator (CAISO), that have not been developed through a public process in the resource adequacy docket and have not approved by the Commission;
2. The resource selection excluded certain resources for eligibility in meeting the local capacity requirements because CAISO failed to study whether those resources could meet the system resource adequacy requirements;
3. There was incomplete information relative to competitive alternatives that EnerNOC would face that made it difficult to determine the availability of customers to participate as resources or the ability to economically attract customers to participate;
4. DR resource requirements, as it relates to wholesale market participation in the CAISO's wholesale markets, are under development. Some of those existing requirements are cost-prohibitive barriers to entry. In addition, there is an inability to quantify the exposure to CAISO cost incurrence associated with SCE's bid of EnerNOC's DR resources into the wholesale market.
5. SCE indicated that it selected a peaking, gas-fired generator (GFG) as a capacity resource, because it did not need the resource for energy or ancillary services. This is exactly the type of capacity that DR resources could provide.

Q65. Who at CAISO was responsible for modeling demand response resources, and for exercising the professional judgment that SCE stated it deferred to on the scope of modeling conducted, that bid into the SCE 2013 RFO for the Moorpark sub-area?

A65. Robert Sparks.

Q66. Is it the testimony of Mr. Sparks that is quoted in D.13-02-015 as saying the ISO "does not believe that demand response can be relied upon to address local capacity needs"?

A66. Yes.

Q67. Is it reasonable for the Commission to acquiesce to the adverse posture of a private non-profit corporation (CAISO) toward demand response resources in contravention of Public Utilities Code Section 454.5(b)(9)(C) that states that utilities must first meet their "unmet resource needs through all available energy efficiency and demand reduction resources that are cost-effective, reliable and feasible."?

A67. No.

Q68. Is it reasonable for the Commission to accept CAISO reliability modeling results for the Moorpark sub-area that use a limiting contingency that is substantially more rigorous than the federal reliability standard or the CAISO Transmission Planning Standard?

A68. No. The most limiting critical contingency for a given area may be the loss of the largest transmission line (an "N-1" event), the federal reliability Category B standard, or the loss of both the largest generator ("G-1") and the largest transmission line (a "G-1, N-1" event), which is a more conservative standard applied by CAISO in California.[64] A utility must be able to continue uninterrupted service under these contingency conditions. More severe contingencies, such as the simultaneous loss of two transmission lines (an "N-2" event) or loss of two transmission lines within less than thirty minutes (an "N-1-1" event) can be addressed with controlled load shedding. These more severe contingencies are classified as Category C or Category D contingencies, depending on the specific details of the transmission lines involved.[65] The limiting contingency in the CAISO model accepted by the Commission in the Track 1 proceeding as the basis for determining the Moorpark sub-area reliability need authorization is the sequential loss of three transmission lines in the same right-of-way, a N-1 event followed by a N-1-1 event, which is a Category D contingency,[66] with no load shedding or mitigation of any kind.

Q69. What is SCE's stated position on the need to address a Category D contingency?

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[64] Exhibit PE-26, CAISO Transmission Planning Standards, June 2011, p. 4.

[65] Exhibit PE-27, R.12-03-014, *Exhibit SCE-1: Track 4 Testimony of Southern California Edison Company (U 338-E),* August 26, 2013, pp. 21-22.

[66] Exhibit PE-28, NERC transmission planning Reliability Standards include TPL-001-3 (Category A), TPL-002-2b (Category B), TPL-003-2b (Category C), and TPL-004-2a (Category D). NERC, *Standard TPL-004-2 — System Performance Following Extreme BES Events, Table I. Transmission System Standards – Normal and Emergency Conditions*, February 7, 2013, p. 5. Category D = Extreme event resulting in two or more (multiple) elements removed or cascading out of service. D6. Loss of towerline with three or more circuits. D7. All transmission lines on a common right-of way

A69. SCE's stated position is that: 1) load shedding can be used to mitigate Category C contingencies, and 2) a utility has no obligation to plan to mitigate an "extreme" Category D contingency. SCE states:[67]

> 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.

Q70. Does SCE have a load shedding protocol to address the Category D contingency used by CAISO to establish the need authorization for the Moorpark sub-area?

A70. No. SCE has no load shedding protocol in place to address the sequential loss of the three Moorpark-Pardee 230 kV lines.[68]

Q71. Is this consistent with the definition of a Category D contingency?

A71. Yes. Utilities are not expected to mitigate Category D events. Utilities are also not expected to use unmitigated Category D contingencies as the basis for LCR need determinations.

Q72. Has CAISO previously stated that use of controlled load shedding to address Category C and Category D contingencies is reasonable and appropriate?

A72. Yes. CAISO expressed no reservations about using load shedding to meet Category C and Category D contingencies, other than G-1/N-1, when it supported construction of SDG&E's 500 kV Sunrise Powerlink transmission line, stating: [69]

> Involuntary load interruptions are an acceptable consequence in planning for CAISO Planning Standard Category C and D disturbances (multiple contingencies with the exception of the combined outage of a single generator and a single transmission line), unless the CAISO Board decides that the capital project

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[67] Exhibit PE-27, p. 22.

[68] Exhibit PE-29, LCR RFO Moorpark A.14-11-016, Data Request Set A.14-11-016 LCR RFO-CBD-SCE-002, to CBD, April 1, 0215.

[69] Exhibit PE-30, A.05-12-014, *SDG&E Application, Sunrise Powerlink Transmission Project Purpose and Need – Volume 2*, Appendix I-1: CAISO South Regional Transmission Plan for 2006, p. 30, August 4, 2006.

> alternative is clearly cost effective (after considering all the costs and benefits).

Q73. Did CAISO contradict this perspective on load shedding in D.14-03-014 by indicating that load shedding is a stop-gap measure and not an authorized response to the N-1-1 event?

A73. Yes. D.14-03-014 identifies the CAISO position on load shedding as a response to the N-1-1 contingency as:[70]

> The ISO considers an SPS (load shedding) to be a temporary measure to be in place while long lead-time resources, such as new transmission lines, are being constructed.

Q74. Did the Commission initiate a separate proceeding or any other formal process to consider adopting the substantially more conservative N-1 followed by a N-1-1 Category D limiting contingency assumed by CAISO in Track 1 modeling for the Moorpark sub-area, given that use of this more conservative limiting contingency would increase the identified need, and cost to ratepayers, in the Moorpark sub-area specifically and SCE territory generally compared to the standard G-1/N-1 limiting contingency?

A74. No. In D.14-03-14, the Commission concluded it did not have the expertise to make this type of determination, stating:[71]

> Changing a Category C contingency to a Category D contingency would directly change the ISO model output. Issues regarding whether an ISO-determined Category C contingency should instead be functionally a Category D contingency under WECC reliability standards are more within the expertise of the ISO than the Commission.

Q75. Is it reasonable for the Commission to defer to CAISO on the issue of the appropriate limiting contingency to be used to determine reliability need in the Moorpark sub-area?

A75. No. The Commission's deference to CAISO on this very substantial issue, with major cost implications for ratepayers, is not reasonable. The CAISO

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[70] D.14-03-014, p. 37.
[71] D.14-03-014, Findings of Fact 31 and 32, p. 126.

transmission planning standard is G-1/N-1 with no load shedding.[72] This is the same standard used historically by California IOUs prior to the formation of CAISO.[73] Use of Category C or Category D contingencies with little or no load shedding as critical contingencies far exceeds the conservatism already built into the G-1/N-1 planning standard. It is unreasonable for ratepayers to pay to mitigate Category D contingencies.

Q76. Does CAISO assume any load shedding for the N-1 followed by the N-1-1 Category D contingency that drives the Moorpark sub-area need authorization in D.13-02-015?

A76. No.

Q77. Could the Commission have directed SCE and all other parties including CAISO that intended to conduct modeling, to assume sufficient load shedding is realized in response to Category C and Category D contingencies that the effect on need caused by these contingencies would be no greater than that of the G-1/N-1 standard contingency with no load shedding?

A77. Yes.

Q78. Did it do so?

A78. No.

Q79. Does this conclude your opening testimony?

A79. Yes.

[72] Exhibit PE-26, p. 10.
[73] Ibid.

EXHIBIT PE-02

BILL POWERS, P.E.

PROFESSIONAL HISTORY

Powers Engineering, San Diego, CA 1994-
ENSR Consulting and Engineering, Camarillo, CA 1989-93
Naval Energy and Environmental Support Activity, Port Hueneme, CA 1982-87
U.S. Environmental Protection Agency, Research Triangle Park, NC 1980-81

EDUCATION

Master of Public Health – Environmental Sciences, University of North Carolina
Bachelor of Science – Mechanical Engineering, Duke University

PROFESSIONAL AFFILIATIONS

Registered Professional Mechanical Engineer, California (Certificate M24518)
American Society of Mechanical Engineers
Air & Waste Management Association

TECHNICAL SPECIALTIES

Thirty years of experience in:

- Power plant air emission control system and cooling system assessments
- Petroleum refinery air engineering and testing
- Combustion equipment permitting, testing and monitoring
- Air pollution control equipment retrofit design/performance testing
- Distributed solar photovoltaics (PV) siting and regional renewable energy planning
- Latin America environmental project experience

POWER PLANT EMISSION CONTROL AND COOLING SYSTEM CONVERSION ASSESSMENTS

LMS100 Gas Turbine Power Plant Air Emissions Control Assessment. Lead engineer to assess Best Available Control Technology (BACT) for four proposed LMS100 gas turbines to be owned and operated by El Paso Electric Company. El Paso Electric proposed NOx and CO emission rates of 2.5 ppm and 6.0 ppm respectively, use of wet cooling tower(s) for intercooler heat rejection, and up to 5,000 hours per year of operation. I identified BACT as equivalent to combined cycle plant levels, 2.0 ppm NO_x and 2.0 ppm CO, due to high operating hour limit., and air cooling with mist augmentation at high ambient temperatures as BACT for PM. The TCEQ Office of Public Interest Council agreed that BACT for the LMS100s should be 2.0 ppm NO_x and 2.0 ppm CO, and that air cooling with mist augmentation should be BACT for PM**.**

Biomass Plant NO_x and CO Air Emissions Control Evaluation. Lead engineer for evaluation of available nitrogen oxide (NO_x) and carbon monoxide (CO) controls for a 45 MW Aspen Power biomass plant in Texas where proponent had identified selective non-catalytic reduction (SNCR) for NO_x and good combustion practices for CO as BACT. Identified the use of tail-end SCR for NO_x control at several operational U.S. biomass plants, and oxidation catalyst in use at two of these plants for CO and VOC control, as BACT for the proposed biomass plant. Administrative law judge concurred in decision that SCR and oxidation catalyst is BACT. Developer added SCR and oxidation catalyst to project in subsequent settlement agreement.

Biomass Plant Air Emissions Control Consulting. Lead expert on biomass air emissions control systems for landowners that will be impacted by a proposed 50 MW biomass to be built by the local East Texas power cooperative. Public utility agreed to meet current BACT for biomass plants in Texas, SCR for NOx and oxidation catalyst for CO, in settlement agreement with local landowners.

Combined-Cycle Power Plant Startup and Shutdown Emissions. Lead engineer for analysis of air permit startup and shutdown emissions minimization for combined-cycle power plant proposed for the San Francisco Bay Area. Original equipment was specified for baseload operation prior to suspension of project in early 2000s. Operational profile described in revised air permit was load following with potential for daily start/stop. Recommended that either fast start turbine technology be employed to minimize start/stop emissions or that "demonstrated in practice" operational and control software modifications be employed to minimize startup/shutdown emissions.

IGCC as BACT for Air Emissions from Proposed 960 MW Coal Plant. Presented testimony on IGCC as BACT for air emissions reduction from 960 MW coal plant. Applicant received air permit for a pulverized coal plant to be equipped with a baghouse, wet scrubber, and wet ESP for air emissions control. Use of IGCC technology at the emission rates permitted for two recently proposed U.S. IGCC projects, and demonstrated in practice at a Japanese IGCC plant firing Chinese bituminous coal, would substantially reduce potential emissions of NO_x, SO_2, and PM. The estimated control cost-effectiveness of substituting IGCC for pulverized coal technology in this case was approximately $3,000/ton.

Analysis of Proposed Air Emission Limits for 600 MW Pulverized Coal Plant. Project engineer tasked with evaluating sufficiency of air emissions limits and control technologies for proposed 600 MW coal plant Arkansas. Determined that the applicant had: 1) not properly identified SO_2, sulfuric acid mist, and PM BACT control levels for the plant, and 2) improperly utilized an incremental cost effectiveness analysis to justify air emission control levels that did not represent BACT.

Eight Pulverized Coal Fired 900 MW Boilers – IGCC Alternative with Air Cooling. Provided testimony on integrated gasification combined cycle (IGCC) as a fully commercial coal-burning alternative to the pulverized coal (PC) technology proposed by TXU for eight 900 MW boilers in East Texas, and East Texas as an ideal location for CO2 sequestration due to presence of mature oilfield CO2 enhanced oil recovery opportunities and a deep saline aquifer underlying the entire region. Also presented testimony on the major increase in regional consumptive water use that would be caused by the evaporative cooling towers proposed for use in the PC plants, and that consumptive water use could be lowered by using IGCC with evaporative cooling towers or by using air-cooled condensers with PC or IGCC technology. TXU ultimately dropped plans to build the eight PC plants as a condition of a corporate buy-out.

Utility Boilers – Conversion of Existing Once-Through Cooled Boilers to Wet Towers, Parallel Wet-Dry Cooling, or Dry Cooling. Provided expert testimony and preliminary design for the conversion of four natural gas and/or coal-fired utility boilers (Unit 4, 235 MW; Unit 3, 135 MW; Unit 2, 65 MW; and Unit 1,65 MW) from once-through river water cooling to wet cooling towers, parallel wet-dry cooling, and dry cooling. Major design constraints were available land for location of retrofit cooling systems and need to maintain maximum steam turbine backpressure at or below 5.5 inches mercury to match performance capabilities of existing equipment. Approach temperatures of 12 ^oF and 13 ^oF were used for the wet towers. SPX Cooling Technologies F-488 plume-abated wet cells with six feet of packing were used to achieve approach temperatures of 12 ^oF and 13 ^oF. Annual energy penalty of wet tower retrofit designs is approximately 1 percent. Parallel wet-dry or dry cooling was determined to be technically feasible for Unit 3 based on straightforward access to the Unit 3 surface condenser and available land adjacent to the boiler.

Utility Boiler – Assessment of Air Cooling and Integrated Gasification/Combined Cycle for Proposed 500 MW Coal-Fired Plant. Provided expert testimony on the performance of air-cooling and IGCC relative to the conventional closed-cycle wet cooled, supercritical pulverized coal boiler proposed by the applicant. Steam Pro™ coal-fired power plant design software was used to model the proposed plant and evaluate the impacts on performance of air cooling and plume-abated wet cooling. Results indicated that a conservatively designed air-cooled condenser could maintain rated power output at the design ambient temperature of 90 ^oF. The IGCC comparative analysis indicated that unit reliability comparable to a conventional pulverized coal unit could be achieved by including a spare gasifier in the IGCC design, and that the slightly higher capital cost of IGCC was offset by greater thermal efficiency and reduced water demand and air emissions.

Utility Boiler – Assessment of Closed-Cycle Cooling Retrofit Cost for 1,200 MW Oil-Fired Plant. Prepared an assessment of the cost and feasibility of a closed-cycle wet tower retrofit for the 1,200 MW Roseton Generating Station. Determined that the cost to retrofit the Roseton plant with plume-abated closed-cycle wet cooling was well established based on cooling tower retrofit studies performed by the original owner (Central Hudson Gas & Electric Corp.) and subsequent regulatory agency critique of the cost estimate. Also determined that elimination of redundant and/or excessive budgetary line items in owners cost estimate brings the closed-cycle retrofit in line with expected costs for comparable new or retrofit plume-abated cooling tower applications.

Nuclear Power Plant – Assessment of Closed-Cycle Cooling Retrofit Cost for 2,000 MW Plant. Prepared an assessment of the cost and feasibility of a closed-cycle wet tower retrofit for the 2,000 MW Indian Point Generating Station. Determined that the most appropriate arrangement for the hilly site would be an inline plume-abated wet tower instead of the round tower configuration analyzed by the owner. Use of the inline configuration would allow placement of the towers at numerous sites on the property with little or need for blasting of bedrock, greatly reducing the cost of the retrofit. Also proposed an alternative circulating cooling water piping configuration to avoid the extensive downtime projected by the owner for modifications to the existing discharge channel.

Kentucky Coal-Fired Power Plant – Pulverized Coal vs IGCC. Expert witness in Sierra Club lawsuit against Peabody Coal Company's plan to construct a 1,500 MW pulverized-coal fired power plant in Kentucky. Presented case that Integrated Gasification Combined Cycle (IGCC) is a superior method for producing power from coal, from environmental and energy efficiency perspective, than the proposed pulverized-coal plant. Presented evidence that IGCC is technically feasible and cost competitive with pulverized coal.

Power Plant Dry Cooling Symposium – Chair and Organizer. Chair and organizer of the first symposium held in the U.S. (May 2002) that focused exclusively on dry cooling technology for power plants. Sessions included basic principles of wet and dry cooling systems, performance capabilities of dry cooling systems, case studies of specific installations, and reasons why dry cooling is the predominant form of cooling specified in certain regions of North America (Massachusetts, Nevada, northern Mexico).

Utility Boiler – Best Available NO_x Control System for 525 MW Coal-Fired Circulating Fluidized Bed Boiler Plant. Expert witness in dispute over whether 50 percent NO_x control using selective non-catalytic reduction (SNCR) constituted BACT for a proposed 525 MW circulating fluidized bed (CFB) boiler plant. Presented testimony that SNCR was capable of continuous NO_x reduction of greater than 70 percent on a CFB unit and that tail-end selective catalytic reduction (SCR) was technically feasible and could achieve greater than 90 percent NO_x reduction.

Utility Boilers – Evaluation of Correlation Between Opacity and PM_{10} Emissions at Coal-Fired Plant. Provided expert testimony on whether correlation existed between mass PM_{10} emissions and opacity during opacity excursions at large coal-fired boiler in Georgia. EPA and EPRI technical studies were reviewed to assess the correlation of opacity and mass emissions during opacity levels below and above 20 percent. A strong correlation between opacity and mass emissions was apparent at a sister plant at opacities less than 20 percent. The correlation suggests that the opacity monitor correlation underestimates mass emissions at opacities greater than 20 percent, but may continue to exhibit a good correlation for the component of mass emissions in the PM_{10} size range.

Utility Boilers – Retrofit of SCR and FGD to Existing Coal-Fired Units.
Expert witness in successful effort to compel an existing coal-fired power plant located in Massachusetts to meet an accelerated NO_x and SO_2 emission control system retrofit schedule. Plant owner argued the installation of advanced NO_x and SO_2 control systems would generate > 1 ton/year of ancillary emissions, such as sulfuric acid mist, and that under Massachusetts Dept. of Environmental Protection regulation ancillary emissions > 1 ton/year would require a BACT evaluation and a two-year extension to retrofit schedule. Successfully demonstrated that no ancillary emissions would be generated if the retrofit NO_x and SO_2 control systems were properly sized and optimized. Plant owner committed to accelerated compliance schedule in settlement agreement.

Utility Boilers – Retrofit of SCR to Existing Natural Gas-Fired Units.
Lead engineer in successful representation of interests of California coastal city to prevent weakening of an existing countywide utility boiler NO_x rule. Weakening of NO_x rule would have allowed a merchant utility boiler plant located in the city to operate without installing selective catalytic reduction (SCR) NO_x control systems. This project required numerous appearances before the county air pollution control hearing board to successfully defend the existing utility boiler NO_x rule.

PETROLEUM REFINERY AIR ENGINEERING/TESTING EXPERIENCE

BP Whiting Refinery Expansion Air Permit. Served as lead engineer on review of netting analysis that resulted in the BP Whiting Refinery Expansion receiving a minor source air permit from the Indiana Department of Environmental Management. Determined that BP Whiting omitted several major sources of emissions, underestimated others, and incorrectly calculated contemporaneous increases and decreases in air emissions. These sources included refinery heaters, flares, coking units, sulfur recovery, and fugitive emissions. These errors and omissions were sufficient in number and magnitude to exceed NSR significance thresholds.

Hyperion Refinery Air Permit. Served as lead engineer on review of BACT determinations in the PSD air permit for the proposed Hyperion Refinery in South Dakota.. BACT review included controls for refinery heaters, cooling systems, fugitive emissions, and greenhouse gases. BACT was identified as SCR for all refinery heaters, use of enclosed ground flare for periodic flare gas emissions from gasification process, and use of leakless fugitive emission components.

Big West Refinery Expansion EIS. Lead engineer on comparative cost analysis of proposed wet cooling tower and fin-fan air cooler for process cooling water for the proposed clean fuels expansion project at the Big West Refinery in Bakersfield, California. Selection of the fin-fin air-cooler would eliminate all consumptive water use and wastewater disposal associated with the cooling tower. Air emissions of VOC and PM_{10} would be reduced with the fin-fan air-cooler even though power demand of the air-cooler is incrementally higher than that of the cooling tower. Fin-fan air-coolers with approach temperatures of 10 ^oF and 20 ^oF were evaluated. The annualized cost of the fin-fin air-cooler with a 20 ^oF approach temperature is essentially the same as that of the cooling tower when the cost of all ancillary cooling tower systems are considered.

Criteria and Air Toxic Pollutant Emissions Inventory for Proposed Refinery Modifications. Project manager and technical lead for development of baseline and future refinery air emissions inventories for process modifications required to produce oxygenated gasoline and desulfurized diesel fuel at a California refinery. State of the art criteria and air toxic pollutant emissions inventories for refinery point, fugitive and mobile sources were developed. Point source emissions estimates were generated using onsite criteria pollutant test data, onsite air toxics test data, and the latest air toxics emission factors from the statewide refinery air toxics inventory database. The fugitive volatile organic compound (VOC) emissions inventories were developed using the refinery's most recent inspection and maintenance (I&M) monitoring program test data to develop site-specific component VOC emission rates. These VOC emission rates were combined with speciated air toxics test results for the principal refinery process streams to produce fugitive VOC air toxics emission rates. The environmental impact report (EIR) that utilized this emission inventory data was the first refinery "Clean Fuels" EIR approved in California.

Development of Air Emission Standards for Petroleum Refinery Equipment - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian petroleum refineries. The sources included in the scope of this project included: 1) SO_2 and NO_x refinery heaters and boilers, 2) desulfurization of crude oil, particulate and SO_2 controls for fluid catalytic cracking units (FCCU), 3) VOC and CO emissions from flares, 4) vapor recovery systems for marine unloading, truck loading, and crude oil/refined products storage tanks, and 5) VOC emissions from process fugitive sources such as pressure relief valves, pumps, compressors and flanges. Proposed emission limits were developed for new and existing refineries based on a thorough evaluation of the available air emission control technologies for the affected refinery sources. Leading vendors of refinery control technology, such as John Zink and Exxon Research, provided estimates of retrofit costs for the largest Peruvian refinery, La Pampilla, located in Lima. Meetings were held in Lima with refinery operators and MEM staff to discuss the proposed emission limits and incorporate mutually agreed upon revisions to the proposed limits for existing Peruvian refineries.

Air Toxic Pollutant Emissions Inventory for Existing Refinery. Project manager and technical lead for air toxic pollutant emissions inventory at major California refinery. Emission factors were developed for refinery heaters, boilers, flares, sulfur recovery units, coker deheading, IC engines, storage tanks, process fugitives, and catalyst regeneration units. Onsite source test results were utilized to characterize emissions from refinery combustion devices. Where representative source test results were not available, AP-42 VOC emission factors were combined with available VOC air toxics speciation profiles to estimate VOC air toxic emission rates. A risk assessment based on this emissions inventory indicated a relatively low health risk associated with refinery operations. Benzene, 1,3-butadiene and PAHs were the principal health risk related pollutants emitted.

Air Toxics Testing of Refinery Combustion Sources. Project manager for comprehensive air toxics testing program at a major California refinery. Metals, Cr^{+6}, PAHs, H_2S and speciated VOC emissions were measured from refinery combustion sources. High temperature Cr^{+6} stack testing using the EPA Cr^{+6} test method was performed for the first time in California during this test program. Representatives from the California Air Resources Board source test team performed simultaneous testing using ARB Method 425 (Cr^{+6}) to compare the results of EPA and ARB Cr^{+6} test methodologies. The ARB approved the test results generated using the high temperature EPA Cr^{+6} test method.

Air Toxics Testing of Refinery Fugitive Sources. Project manager for test program to characterize air toxic fugitive VOC emissions from fifteen distinct process units at major California refinery. Gas, light liquid, and heavy liquid process streams were sampled. BTXE, 1,3-butadiene and propylene concentrations were quantified in gas samples, while BTXE, cresol and phenol concentrations were measured in liquid samples. Test results were combined with AP-42 fugitive VOC emission factors for valves, fittings, compressors, pumps and PRVs to calculate fugitive air toxics VOC emission rates.

COMBUSTION EQUIPMENT PERMITTING, TESTING AND MONITORING

EPRI Gas Turbine Power Plant Permitting Documents – Co-Author.
Co-authored two Electric Power Research Institute (EPRI) gas turbine power plant siting documents. Responsibilities included chapter on state-of-the-art air emission control systems for simple-cycle and combined-cycle gas turbines, and authorship of sections on dry cooling and zero liquid discharge systems.

Air Permits for 50 MW Peaker Gas Turbines – Six Sites Throughout California.
Responsible for preparing all aspects of air permit applications for five 50 MW FT-8 simple-cycle turbine installations at sites around California in response to emergency request by California state government for additional peaking power. Units were designed to meet 2.0 ppm NO_x using standard temperature SCR and innovative dilution air system to maintain exhaust gas temperature within acceptable SCR range.

Oxidation catalyst is also used to maintain CO below 6.0 ppm.

Kauai 27 MW Cogeneration Plant – Air Emission Control System Analysis. Project manager to evaluate technical feasibility of SCR for 27 MW naphtha-fired turbine with once-through heat recovery steam generator. Permit action was stalled due to questions of SCR feasibility. Extensive analysis of the performance of existing oil-fired turbines equipped with SCR, and bench-scale tests of SCR applied to naphtha-fired turbines, indicated that SCR would perform adequately. Urea was selected as the SCR reagent given the wide availability of urea on the island. Unit is first known application of urea-injected SCR on a naphtha-fired turbine.

Microturbines – Ronald Reagan Library, Ventura County, California.
Project manager and lead engineer or preparation of air permit applications for microturbines and standby boilers. The microturbines drive the heating and cooling system for the library. The microturbines are certified by the manufacturer to meet the 9 ppm NO_x emission limit for this equipment. Low-NO_x burners are BACT for the standby boilers.

Hospital Cogeneration Microturbines – South Coast Air Quality Management District.
Project manager and lead engineer for preparation of air permit application for three microturbines at hospital cogeneration plant installation. The draft Authority To Construct (ATC) for this project was obtained two weeks after submittal of the ATC application. 30-day public notification was required due to the proximity of the facility to nearby schools. The final ATC was issued two months after the application was submitted, including the 30-day public notification period.

Gas Turbine Cogeneration – South Coast Air Quality Management District. Project manager and lead engineer for preparation of air permit application for two 5.5 MW gas turbines in cogeneration configuration for county government center. The turbines will be equipped with selective catalytic reduction (SCR) and oxidation catalyst to comply with SCAQMD BACT requirements. Aqueous urea will be used as the SCR reagent to avoid trigger hazardous material storage requirements. A separate permit will be obtained for the NO_x and CO continuous emissions monitoring systems. The ATCs is pending.

Industrial Boilers – NO_x BACT Evaluation for San Diego County Boilers.
Project manager and lead engineer for preparation of Best Available Control Technology (BACT) evaluation for three industrial boilers to be located in San Diego County. The BACT included the review of low NO_x burners, FGR, SCR, and low temperature oxidation (LTO). State-of-the-art ultra low NO_x burners with a 9 ppm emissions guarantee were selected as NO_x BACT for these units.

Peaker Gas Turbines – Evaluation of NO_x Control Options for Installations in San Diego County.
Lead engineer for evaluation of NO_x control options available for 1970s vintage simple-cycle gas turbines proposed for peaker sites in San Diego County. Dry low-NO_x (DLN) combustors, catalytic combustors, high-temperature SCR, and NO_x absorption/conversion (SCONO$_x$) were evaluated for each candidate turbine make/model. High-temperature SCR was selected as the NOx control option to meet a 5 ppm NO_x emission requirement.

Hospital Cogeneration Plant Gas Turbines – San Joaquin Valley Unified Air Pollution Control District.
Project manager and lead engineer for preparation of air permit application and Best Available Control Technology (BACT) evaluation for hospital cogeneration plant installation. The BACT included the review of DLN combustors, catalytic combustors, high-temperature SCR and SCONO$_x$. DLN combustion followed by high temperature SCR was selected as the NO_x control system for this installation. The high temperature SCR is located upstream of the heat recovery steam generator (HRSG) to allow the diversion of exhaust gas around the HRSG without compromising the effectiveness of the NO_x control system.

1,000 MW Coastal Combined-Cycle Power Plant – Feasibility of Dry Cooling.
Expert witness in on-going effort to require use of dry cooling on proposed 1,000 MW combined-cycle "repower" project at site of an existing 1,000 MW utility boiler plant. Project proponent argued that site was

two small for properly sized air-cooled condenser (ACC) and that use of ACC would cause 12-month construction delay. Demonstrated that ACC could easily be located on the site by splitting total of up to 80 cells between two available locations at the site. Also demonstrated that an ACC optimized for low height and low noise would minimize or eliminate proponent claims of negative visual and noise impacts.

Industrial Cogeneration Plant Gas Turbines – Upgrade of Turbine Power Output.
Project manager and lead engineer for preparation of Best Available Control Technology (BACT) evaluation for proposed gas turbine upgrade. The BACT included the review of DLN combustors, catalytic combustors, high-, standard-, and low-temperature SCR, and $SCONO_x$. Successfully negotiated air permit that allowed facility to initially install DLN combustors and operate under a NO_x plantwide "cap." Within two major turbine overhauls, or approximately eight years, the NO_x emissions per turbine must be at or below the equivalent of 5 ppm. The 5 ppm NO_x target will be achieved through technological in-combustor NO_x control such as catalytic combustion, or SCR or SCR equivalent end-of-pipe NO_x control technologies if catalytic combustion is not available.

Gas Turbines – Modification of RATA Procedures for Time-Share CEM.
Project manager and lead engineer for the development of alternate CO continuous emission monitor (CEM) Relative Accuracy Test Audit (RATA) procedures for time-share CEM system serving three 7.9 MW turbines located in San Diego. Close interaction with San Diego APCD and EPA Region 9 engineers was required to receive approval for the alternate CO RATA standard. The time-share CEM passed the subsequent annual RATA without problems as a result of changes to some of the CEM hardware and the more flexible CO RATA standard.

Gas Turbines – Evaluation of NO_x Control Technology Performance. Lead engineer for performance review of dry low-NO_x combustors, catalytic combustors, high-, standard-, and low-temperature selective catalytic reduction (SCR), and NO_x absorption/conversion ($SCONO_x$). Major turbine manufacturers and major manufacturers of end-of-pipe NO_x control systems for gas turbines were contacted to determine current cost and performance of NO_x control systems. A comparison of 1993 to 1999 "$/kwh" and "$/ton" cost of these control systems was developed in the evaluation.

Gas Turbines – Evaluation of Proposed NO_x Control System to Achieve 3 ppm Limit.
Lead engineer for evaluation for proposed combined cycle gas turbine NO_x and CO control systems. Project was in litigation over contract terms, and there was concern that the GE Frame 7FA turbine could not meet the 3 ppm NO_x permit limit using a conventional combustor with water injection followed by SCR. Operations personnel at GE Frame 7FA installatins around the country were interviewed, along with principal SCR vendors, to corroborate that the installation could continuously meet the 3 ppm NO_x limit.

Gas Turbines – Title V "Presumptively Approvable" Compliance Assurance Monitoring Protocol.
Project manager and lead engineer for the development of a "presumptively approval" NO_x parametric emissions monitoring system (PEMS) protocol for industrial gas turbines. "Presumptively approvable" means that any gas turbine operator selecting this monitoring protocol can presume it is acceptable to the U.S. EPA. Close interaction with the gas turbine manufacturer's design engineering staff and the U.S. EPA Emissions Measurement Branch (Research Triangle Park, NC) was required to determine modifications necessary to the current PEMS to upgrade it to "presumptively approvable" status.

Environmental Due Diligence Review of Gas Turbine Sites – Mexico. Task leader to prepare regulatory compliance due diligence review of Mexican requirements for gas turbine power plants. Project involves eleven potential sites across Mexico, three of which are under construction. Scope involves identification of all environmental, energy sales, land use, and transportation corridor requirements for power projects in Mexico. Coordinator of Mexican environmental subcontractors gathering on-site information for each site, and translator of Spanish supporting documentation to English.

Development of Air Emission Standards for Gas Turbines - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian gas turbine power plants. All major gas turbine power plants in Peru are currently using water injection to increase turbine power output. Recommended that 42 ppm on natural gas and 65 ppm on diesel (corrected to 15% O_2) be established as the NO_x limit for existing gas turbine power plants. These limits reflect NO_x levels readily achievable using water injection at high load. Also recommended that new gas turbine sources be subject to a BACT review requirement.

Gas Turbines – Title V Permit Templates. Lead engineer for the development of standardized permit templates for approximately 100 gas turbines operated by the oil and gas industry in the San Joaquin Valley. Emissions limits and monitoring requirements were defined for units ranging from GE Frame 7 to Solar Saturn turbines. Stand-alone templates were developed based on turbine size and NO_x control equipment. NO_x utilized in the target turbine population ranged from water injection alone to water injection combined with SCR.

Gas Turbines – Evaluation of NO_x, SO_2 and PM Emission Profiles. Performed a comparative evaluation of the NO_x, SO_2 and particulate (PM) emission profiles of principal utility-scale gas turbines for an independent power producer evaluating project opportunities in Latin America. All gas turbine models in the 40 MW to 240 MW range manufactured by General Electric, Westinghouse, Siemens and ABB were included in the evaluation.

Stationary Internal Combustion Engine (ICE) RACT/BARCT Evaluation. Lead engineer for evaluation of retrofit NO_x control options available for the oil and gas production industry gas-fired ICE population in the San Joaquin Valley affected by proposed RACT and BARCT emission limits. Evaluation centered on lean-burn compressor engines under 500 bhp, and rich-burn constant and cyclically loaded (rod pump) engines under 200 bhp. The results of the evaluation indicated that rich burn cyclically-loaded rod pump engines comprised 50 percent of the affected ICE population, though these ICEs accounted for only 5 percent of the uncontrolled gas-fired stationary ICE NO_x emissions. Recommended retrofit NO_x control strategies included: air/fuel ratio adjustment for rod pump ICEs, Non-selective catalytic reduction (NSCR) for rich-burn, constant load ICEs, and "low emission" combustion modifications for lean burn ICEs.

Development of Air Emission Standards for Stationary ICEs - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian stationary ICE power plants. Draft 1997 World Bank NO_x and particulate emission limits for stationary ICE power plants served as the basis for proposed MEM emission limits. A detailed review of ICE emissions data provided in PAMAs submitted to the MEM was performed to determine the level of effort that would be required by Peruvian industry to meet the proposed NO_x and particulate emission limits. The draft 1997 WB emission limits were revised to reflect reasonably achievable NO_x and particulate emission limits for ICEs currently in operation in Peru.

Air Toxics Testing of Natural Gas-Fired ICEs. Project manager for test plan/test program to measure volatile and semi-volatile organic air toxics compounds from fourteen gas-fired ICEs used in a variety of oil and gas production applications. Test data was utilized by oil and gas production facility owners throughout California to develop accurate ICE air toxics emission inventories.

AIR ENGINEERING/AIR TESTING PROJECT EXPERIENCE – GENERAL

Reverse Air Fabric Filter Retrofit Evaluation – Coal-Fired Boiler. Lead engineer for upgrade of reverse air fabric filters serving coal-fired industrial boilers. Fluorescent dye injected to pinpoint broken bags and damper leaks. Corrosion of pneumatic actuators serving reverse air valves and inadequate insulation identified as principal causes of degraded performance.

Pulse-Jet Fabric Filter Performance Evaluation – Gold Mine. Lead engineer on upgrade of pulse-jet fabric filter and associated exhaust ventilation system serving an ore-crushing facility at a gold mine. Fluorescent dye used to identify bag collar leaks, and modifications were made to pulse air cycle time and duration. This marginal source was in compliance at 20 percent of emission limit following completion of repair work.

Pulse-Jet Fabric Filter Retrofit - Gypsum Calciner. Lead engineer on upgrade of pulse-jet fabric filter controlling particulate emissions from a gypsum calciner. Recommendations included a modified bag clamping mechanism, modified hopper evacuation valve assembly, and changes to pulse air cycle time and pulse duration.

Wet Scrubber Retrofit – Plating Shop. Project engineer on retrofit evaluation of plating shop packed-bed wet scrubbers failing to meet performance guarantees during acceptance trials, due to excessive mist carryover. Recommendations included relocation of the mist eliminator (ME), substitution of the original chevron blade ME with a mesh pad ME, and use of higher density packing material to improve exhaust gas distribution. Wet scrubbers passed acceptance trials following completion of recommended modifications.

Electrostatic Precipitator (ESP) Retrofit Evaluation – MSW Boiler. Lead engineer for retrofit evaluation of single field ESP on a municipal solid waste (MSW) boiler. Recommendations included addition of automated power controller, inlet duct turning vanes, and improved collecting plate rapping system.

ESP Electric Coil Rapper Vibration Analysis Testing - Coal-Fired Boiler. Lead engineer for evaluation of ESP rapper effectiveness test program on three field ESP equipped with "magnetically induced gravity return" (MIGR) rappers. Accelerometers were placed in a grid pattern on ESP collecting plates to determine maximum instantaneous plate acceleration at a variety of rapper power setpoints. Testing showed that the rappers met performance specification requirements.

Aluminum Remelt Furnace Particulate Emissions Testing. Project manager and lead engineer for high temperature (1,600 ^{o}F) particulate sampling of a natural gas-fired remelt furnace at a major aluminum rolling mill. Objectives of test program were to: 1) determine if condensable particulate was present in stack gases, and 2) to validate the accuracy of the in-stack continuous opacity monitor (COM). Designed and constructed a customized high temperature (inconel) PM_{10}/Mtd 17 sampling assembly for test program. An onsite natural gas-fired boiler was also tested to provide comparative data for the condensable particulate portion of the test program. Test results showed that no significant levels of condensable particulate in the remelt furnace exhaust gas, and indicated that the remelt furnace and boiler had similar particulate emission rates. Test results also showed that the COM was accurate.

Aluminum Remelt Furnace CO and NO_x Testing. Project manager and lead engineer for continuous week-long testing of CO and NO_x emissions from aluminum remelt furnace. Objective of test program was to characterize CO and NO_x emissions from representative remelt furnace for use in the facility's criteria pollution emissions inventory. A TECO Model 48 CO analyzer and a TECO Model 10 NO_x analyzer were utilized during the test program to provide $\pm$1 ppm measurement accuracy, and all test data was recorded by an automated data acquisition system.

Distributed Solar PV siting and Regional Renewable Energy Planning

Bay Area Smart Energy 2020 Plan . Author of the March 2012 *Bay Area Smart Energy 2020* strategic energy plan for the nine-county region surrounding San Francisco Bay. This plan uses the zero net energy building targets in the *California Energy Efficiency Strategic Plan* as a framework to achieve a 60 percent reduction in GHG emissions from Bay Area electricity usage, and a 50 percent reduction in peak demand for grid electricity, by 2020. The 2020 targets in the plan include: 25 percent of detached homes and 20 percent of commercial buildings achieving zero net energy, adding 200 MW of community-scale microgrid battery storage and 400 MW of utility-scale battery storage, reduction in air conditioner loads by 50 percent through air conditioner cycling and targeted incentive funds to assure highest efficiency replacement units, and cooling system modifications to increase power output from The Geysers geothermal production zone in Sonoma County. Report is available online at: http://pacificenvironment.org/-1-87.

Solar PV technology selection and siting for SDG&E Solar San Diego project. Served as PV technology expert in California Public Utilities Commission proceeding to define PV technology and sites to be used in San Diego Gas & Electric (SDG&E) $250 million "Solar San Diego" project. Recommendations included: 1) prioritize use of roof-mounted thin-film PV arrays similar to the SCE urban PV program to maximize the installed PV capacity, 2) avoid tracking ground-mounted PV arrays due to high cost and relative lack of available land in the urban/suburban core, 3) and incorporate limited storage in fixed rooftop PV arrays to maximizing output during peak demand periods. Suitable land next to SDG&E substations capable of supporting 5 to 40 MW of PV (each) was also identified by Powers Engineering as a component of this project.

Rooftop PV alternative to natural gas-fired peaking gas turbines, Chula Vista. Served as PV technology expert in California Energy Commission (CEC) proceeding regarding the application of MMC Energy to build a 100 MW peaking gas turbine power plant in Chula Vista. Presented testimony that 100 MW of PV arrays in the Chula Vista area could provide the same level of electrical reliability on hot summer days as an equivalent amount of peaking gas turbine capacity at approximately the same cost of energy. The preliminary decision issued by the presiding CEC commissioner in the case recommended denial of the application in part due to failure of the applicant or CEC staff to thoroughly evaluate the PV alternative to the proposed turbines. No final decision has yet been issued in the proceeding (as of May 2009).

San Diego Smart Energy 2020 Plan. Author of October 2007 "San Diego Smart Energy 2020," an energy plan that focuses on meeting the San Diego region's electric energy needs through accelerated integration of renewable and non-renewable distributed generation, in the form of combined heat and power (CHP) systems and solar photovoltaic (PV) systems. PV would meet approximately 28 percent of the San Diego region's electric energy demand in 2020. Annual energy demand would drop 20 percent in 2020 relative to 2003 through use all cost-effective energy efficiency measures. Existing utility-scale gas-fired generation would continue to be utilized to provide power at night, during cloudy whether, and for grid reliability support. Report at: http://www.etechinternational.org/new_pdfs/smartenergy/52008_SmE2020_2nd.pdf

Development of San Diego Regional Energy Strategy 2030. Participant in the 18-month process in the 2002-2003 timeframe that led to the development of the San Diego Regional Energy Strategy 2030. This document was adopted by the SANDAG Board of Directors in July 2003 and defines strategic energy objectives for the San Diego region, including: 1) in-region power generation increase from 65% of peak demand in 2010 to 75% of peak demand in 2020, 2) 40% renewable power by 2030 with at least half of this power generated in-county, 3) reinforcement of transmission capacity as needed to achieve these objectives. The SANDAG Board of Directors voted unanimously on Nov. 17, 2006 to take no position on the Sunrise Powerlink proposal primarily because it conflicts the Regional Energy Strategy 2030 objective of increased in-region power generation. The Regional Energy Strategy 2030 is online at: http://www.energycenter.org/uploads/Regional_Energy_Strategy_Final_07_16_03.pdf

OIL AND GAS PRODUCTION AIR ENGINEERING/TESTING EXPERIENCE

Air Toxics Testing of Oil and Gas Production Sources. Project manager and lead engineer for test plan/test program to determine VOC removal efficiency of packed tower scrubber controlling sulfur dioxide emissions from a crude oil-fired steam generator. Ratfisch 55 VOC analyzers were used to measure the packed tower scrubber VOC removal efficiency. Tedlar bag samples were collected simultaneously to correlate BTX removal efficiency to VOC removal efficiency. This test was one of hundreds of air toxics tests performed during this test program for oil and gas production facilities from 1990 to 1992. The majority of the volatile air toxics analyses were performed at in-house laboratory. Project staff developed thorough familiarity with the applications and limitations of GC/MS, GC/PID, GC/FID, GC/ECD and GC/FPD. Tedlar bags, canisters, sorbent tubes and impingers were used during sampling, along with isokinetic tests methods for multiple metals and PAHs.

Air Toxics Testing of Glycol Reboiler – Gas Processing Plant. Project manager for test program to determine emissions of BTXE from glycol reboiler vent at gas processing facility handling 12 MM/cfd of produced gas. Developed innovative test methods to accurately quantify BTXE emissions in reboiler vent gas.

Air Toxics Emissions Inventory Plan. Lead engineer for the development of generic air toxics emission estimating techniques (EETs) for oil and gas production equipment. This project was performed for the Western States Petroleum Association in response to the requirements of the California Air Toxics "Hot Spots" Act. EETs were developed for all point and fugitive oil and gas production sources of air toxics, and the specific air toxics associated with each source were identified. A pooled source emission test methodology was also developed to moderate the cost of source testing required by the Act.

Fugitive NMHC Emissions from TEOR Production Field. Project manager for the quantification of fugitive Nonmethane hydrocarbon (NMHC) emissions from a thermally enhanced oil recovery (TEOR) oil production field in Kern County, CA. This program included direct measurement of NMHC concentrations in storage tank vapor headspace and the modification of available NMHC emission factors for NMHC-emitting devices in TEOR produced gas service, such as wellheads, vapor trunklines, heat exchangers, and compressors. Modification of the existing NMHC emission factors was necessary due to the high concentration of CO_2 and water vapor in TEOR produced gases.

Fugitive Air Emissions Testing of Oil and Gas Production Fields. Project manager for test plan/test program to determine VOC and air toxics emissions from oil storage tanks, wastewater storage tanks and produced gas lines. Test results were utilized to develop comprehensive air toxics emissions inventories for oil and gas production companies participating in the test program.

Oil and Gas Production Field – Air Emissions Inventory and Air Modeling. Project manager for oil and gas production field risk assessment. Project included review and revision of the existing air toxics emission inventory, air dispersion modeling, and calculation of the acute health risk, chronic non-carcinogenic risk and carcinogenic risk of facility operations. Results indicated that fugitive H_2S emissions from facility operations posed a potential health risk at the facility fenceline.

TITLE V PERMIT APPLICATION/MONITORING PLAN EXPERIENCE

Title V Permit Application – San Diego County Industrial Facility. Project engineer tasked with preparing streamlined Title V operating permit for U.S. Navy facilities in San Diego. Principal emission units included chrome plating, lead furnaces, IC engines, solvent usage, aerospace coating and marine coating operations. For each device category in use at the facility, federal MACT requirements were integrated with District requirements in user friendly tables that summarized permit conditions and compliance status.

Title V Permit Application Device Templates - Oil and Gas Production Industry. Project manager and lead engineer to prepare Title V permit application "templates" for the Western States Petroleum Association (WSPA). The template approach was chosen by WSPA to minimize the administrative burden associated with listing permit conditions for a large number of similar devices located at the same oil and gas production facility. Templates are being developed for device types common to oil and gas production operations. Device types include: boilers, steam generators, process heaters, gas turbines, IC engines, fixed-roof storage tanks, fugitive components, flares, and cooling towers. These templates will serve as the core of Title V permit applications prepared for oil and gas production operations in California.

Title V Permit Application - Aluminum Rolling Mill. Project manager and lead engineer for Title V permit application prepared for largest aluminum rolling mill in the western U.S. Responsible for the overall direction of the permit application project, development of a monitoring plan for significant emission units, and development of a hazardous air pollutant (HAP) emissions inventory. The project involved extensive onsite data gathering, frequent interaction with the plant's technical and operating staff, and coordination with legal counsel and subcontractors. The permit application was completed on time and in budget.

Title V Model Permit - Oil and Gas Production Industry. Project manager and lead engineer for the comparative analysis of regional and federal requirements affecting oil and gas production industry sources located in the San Joaquin Valley. Sources included gas turbines, IC engines, steam generators, storage tanks, and process fugitives. From this analysis, a model applicable requirements table was developed for a sample device type (storage tanks) that covered the entire population of storage tanks operated by the industry. The U.S. EPA has tentatively approved this model permit approach, and work is ongoing to develop comprehensive applicable requirements tables for each major category of sources operated by the oil and gas industry in the San Joaquin Valley.

Title V Enhanced Monitoring Evaluation of Oil and Gas Production Sources. Lead engineer to identify differences in proposed EPA Title V enhanced monitoring protocols and the current monitoring requirements for oil and gas production sources in the San Joaquin Valley. The device types evaluated included: steam generators, stationary ICEs, gas turbines, fugitives, fixed roof storage tanks, and thermally enhanced oil recovery (TEOR) well vents. Principal areas of difference included: more stringent Title V O&M requirements for parameter monitors (such as temperature, fuel flow, and O_2), and more extensive Title V recordkeeping requirements.

RACT/BARCT/BACT EVALUATIONS

BACT Evaluation of Wool Fiberglass Insulation Production Line. Project manager and lead engineer for BACT evaluation of a wool fiberglass insulation production facility. The BACT evaluation was performed as a component of a PSD permit application. The BACT evaluation included a detailed analysis of the available control options for forming, curing and cooling sections of the production line. Binder formulations, wet electrostatic precipitators, wet scrubbers, and thermal oxidizers were evaluated as potential PM_{10} and VOC control options. Low NO_x burner options and combustion control modifications were examined as potential NO_x control techniques for the curing oven burners. Recommendations included use of a proprietary binder formulation to achieve PM_{10} and VOC BACT, and use of low-NO_x burners in the curing ovens to achieve NO_x BACT. The PSD application is currently undergoing review by EPA Region 9.

RACT/BARCT Reverse Jet Scrubber/Fiberbed Mist Eliminator Retrofit Evaluation. Project manager and lead engineer on project to address the inability of existing wet electrostatic precipitators (ESPs) and atomized mist scrubbers to adequately remove low concentration submicron particulate from high volume recovery boiler exhaust gas at the Alaska Pulp Corporation mill in Sitka, AK. The project involved thorough on-site inspections of existing control equipment, detailed review of maintenance and performance records, and a detailed evaluation of potential replacement technologies. These technologies included a wide variety of scrubbing technologies where manufacturers claimed high removal efficiencies on submicron particulate in high humidity exhaust gas. Packed tower scrubbers, venturi scrubbers, reverse jet scrubbers, fiberbed mist eliminators and wet ESPs were evaluated. Final recommendations included replacement of atomized mist scrubber with reverse jet scrubber and upgrading of the existing wet ESPs. The paper describing this project was published in the May 1992 TAPPI Journal.

Aluminum Smelter RACT Evaluation - Prebake. Project manager and technical lead for CO and PM_{10} RACT evaluation for prebake facility. Retrofit control options for CO emissions from the anode bake furnace, potline dry scrubbers and the potroom roof vents were evaluated. PM_{10} emissions from the coke kiln, potline dry scrubbers, potroom roof vents, and miscellaneous potroom fugitive sources were addressed. Four CO control technologies were identified as technologically feasible for potline CO emissions: potline current efficiency improvement through the addition of underhung busswork and automated puncher/feeders, catalytic incineration, recuperative incineration and regenerative incineration. Current efficiency improvement was identified as probable CO RACT if onsite test program demonstrated the effectiveness of this approach. Five PM_{10} control technologies were identified as technologically feasible: increased potline hooding efficiency through redesign of shields, the addition of a dense-phase conveying system, increased potline air evacuation rate, wet scrubbing of roof vent emissions, and fabric filter control of roof vent emissions. The cost of these potential PM_{10} RACT controls exceeded regulatory guidelines for cost effectiveness, though testing of modified shield configurations and dense-phase conveying is being conducted under a separate regulatory compliance order.

RACT/BACT Testing/Evaluation of PM_{10} Mist Eliminators on Five-Stand Cold Mill. Project manager and lead engineer for fiberbed mist eliminator and mesh pad mist eliminator comparative pilot test program on mixed phase aerosol (PM_{10})/gaseous hydrocarbon emissions from aluminum high speed cold rolling mill. Utilized modified EPA Method 5 sampling train with portion of sample gas diverted (after particulate filter) to Ratfisch 55 VOC analyzer. This was done to permit simultaneous quantification of aerosol and gaseous hydrocarbon emissions in the exhaust gas. The mesh pad mist eliminator demonstrated good control of PM_{10} emissions, though test results indicated that the majority of captured PM_{10} evaporated in the mesh pad and was emitted as VOC.

Aluminum Remelt Furnace/Rolling Mill RACT Evaluations. Lead engineer for comprehensive CO and PM_{10} RACT evaluation for the largest aluminum sheet and plate rolling mill in western U.S. Significant sources of CO emissions from the facility included the remelt furnaces and the coater line. The potential CO RACT options for the remelt furnaces included: enhanced maintenance practices, preheating combustion air, installation of fully automated combustion controls, and energy efficiency modifications. The coater line was equipped with an afterburner for VOC and CO destruction prior to the initiation of the RACT study. It was determined that the afterburner meets or exceeds RACT requirements for the coater line. Significant sources of PM_{10} emissions included the remelt furnaces and the 80-inch hot rolling mill. Chlorine fluxing in the melting and holding furnaces was identified as the principal source of PM_{10} emissions from the remelt furnaces. The facility is in the process of minimizing/eliminating fluxing in the melting furnaces, and exhaust gases generated in holding furnaces during fluxing will be ducted to a baghouse for PM_{10} control. These modifications are being performed under a separate compliance order, and were determined to exceed RACT requirements. A water-based emulsion coolant and inertial separators are currently in use on the 80-inch hot mill for PM_{10} control. Current practices were determined to meet/exceed PM_{10} RACT for the hot mill. Tray tower absorption/recovery systems were also evaluated to control PM_{10} emissions from the hot mill, though it was determined that the technical/cost feasibility of using this approach on an emulsion-based coolant had not yet been adequately demonstrated.

BARCT Low NO_x Burner Conversion – Industrial Boilers. Lead engineer for evaluation of low NO_x burner options for natural gas-fired industrial boilers. Also evaluated methanol and propane as stand-by fuels to replace existing diesel stand-by fuel system. Evaluated replacement of steam boilers with gas turbine co-generation system.

BACT Packed Tower Scrubber/Mist Eliminator Performance Evaluations. Project manager and lead engineer for Navy-wide plating shop air pollution control technology evaluation and emissions testing program. Mist eliminators and packed tower scrubbers controlling metal plating processes, which included hard chrome, nickel, copper, cadmium and precious metals plating, were extensively tested at three Navy plating shops. Chemical cleaning and stripping tanks, including hydrochloric acid, sulfuric acid, chromic acid and caustic, were also tested. The final product of this program was a military design specification for plating and chemical cleaning shop air pollution control systems. The hydrochloric acid mist sampling procedure developed during this program received a protected patent.

BACT Packed Tower Scrubber/UV Oxidation System Pilot Test Program. Technical advisor for pilot test program of packed tower scrubber/ultraviolet (UV) light VOC oxidation system controlling VOC emissions from microchip manufacturing facility in Los Angeles. The testing was sponsored in part by the SCAQMD's Innovative Technology Demonstration Program, to demonstrate this innovative control technology as BACT for microchip manufacturing operations. The target compounds were acetone, methylethylketone (MEK) and 1,1,1-trichloroethane, and compound concentrations ranged from 10-100 ppmv. The single stage packed tower scrubber consistently achieved greater than 90% removal efficiency on the target compounds. The residence time required in the UV oxidation system for effective oxidation of the target compounds proved significantly longer than the residence time predicted by the manufacturer.

BACT Pilot Testing of Venturi Scrubber on Gas/Aerosol VOC Emission Source. Technical advisor for project to evaluate venturi scrubber as BACT for mixed phase aerosol/gaseous hydrocarbon emissions from deep fat fryer. Venturi scrubber demonstrated high removal efficiency on aerosol, low efficiency on VOC emissions. A number of VOC tests indicated negative removal efficiency. This anomaly was traced to a high hydrocarbon concentration in the scrubber water. The pilot unit had been shipped directly to the jobsite from another test location by the manufacturer without any cleaning or inspection of the pilot unit.

Pulp Mill Recovery Boiler BACT Evaluation. Lead engineer for BACT analysis for control of SO_2, NO_x, CO, TNMHC, TRS and particulate emissions from the proposed addition of a new recovery furnace at a kraft pulp mill in Washington. A "top down" approach was used to evaluate potential control technologies for each of the pollutants considered in the evaluation.

Air Pollution Control Equipment Design Specification Development. Lead engineer for the development of detailed Navy design specifications for wet scrubbers and mist eliminators. Design specifications were based on field performance evaluations conducted at the Long Beach Naval Shipyard, Norfolk Naval Shipyard, and Jacksonville Naval Air Station. This work was performed for the U.S. Navy to provide generic design specifications to assist naval facility engineering divisions with air pollution control equipment selection. Also served as project engineer for the development of Navy design specifications for ESPs and fabric filters.

CONTINUOUS EMISSION MONITOR (CEM) PROJECT EXPERIENCE

Process Heater CO and NO_x CEM Relative Accuracy Testing. Project manager and lead engineer for process heater CO and NO_x analyzer relative accuracy test program at petrochemical manufacturing facility. Objective of test program was to demonstrate that performance of onsite CO and NO_x CEMs was in compliance with U.S. EPA "Boiler and Industrial Furnace" hazardous waste co-firing regulations. A TECO Model 48 CO analyzer and a TECO Model 10 NO_x analyzer were utilized during the test program to provide $\pm$1 ppm measurement accuracy, and all test data was recorded by an automated data acquisition system. One of the two process heater CEM systems tested failed the initial test due to leaks in the gas conditioning system. Troubleshooting was performed using O_2 analyzers, and the leaking component was identified and replaced. This CEM system met all CEM relative accuracy requirements during the subsequent retest.

Performance Audit of NO_x and SO_2 CEMs at Coal-Fired Power Plant. Lead engineer on system audit and challenge gas performance audit of NO_x and SO_2 CEMs at a coal-fired power plant in southern Nevada. Dynamic and instrument calibration checks were performed on the CEMs. A detailed visual inspection of the CEM system, from the gas sampling probes at the stack to the CEM sample gas outlet tubing in the CEM trailer, was also conducted. The CEMs passed the dynamic and instrument calibration requirements specified in EPA's Performance Specification Test - 2 (NO_x and SO_2) alternative relative accuracy requirements.

LATIN AMERICA ENVIRONMENTAL PROJECT EXPERIENCE

Preliminary Design of Ambient Air Quality Monitoring Network – Lima, Peru. Project leader for project to prepare specifications for a fourteen station ambient air quality monitoring network for the municipality of Lima, Peru. Network includes four complete gaseous pollutant, particulate, and meteorological parameter monitoring stations, as well as eight PM_{10} and TSP monitoring stations.

Evaluation of Proposed Ambient Air Quality Network Modernization Project – Venezuela. Analyzed a plan to modernize and expand the ambient air monitoring network in Venezuela. Project was performed for the U.S. Trade and Development Agency. Direct interaction with policy makers at the Ministerio del Ambiente y de los Recursos Naturales Renovables (MARNR) in Caracas was a major component of this project.

Evaluation of U.S.-Mexico Border Region Copper Smelter Compliance with Treaty Obligations – Mexico. Project manager and lead engineer to evaluate compliance of U.S. and Mexican border region copper smelters with the SO_2 monitoring, recordkeeping and reporting requirements in Annex IV [Copper Smelters] of the La Paz Environmental Treaty. Identified potential problems with current ambient and stack monitoring practices that could result in underestimating the impact of SO_2 emissions from some of these copper smelters.

Identified additional source types, including hazardous waste incinerators and power plants, that should be considered for inclusion in the La Paz Treaty process.

Development of Air Emission Limits for ICE Cogeneration Plant - Panamá. Lead engineer assisting U.S. cogeneration plant developer to permit an ICE cogeneration plant at a hotel/casino complex in Panama. Recommended the use of modified draft World Bank NO_x and PM limits for ICE power plants. The modification consisted of adding a thermal efficiency factor adjustment to the draft World Bank NO_x and PM limits. These proposed ICE emission limits are currently being reviewed by Panamanian environmental authorities.

Mercury Emissions Inventory for Stationary Sources in Northern Mexico. Project manager and lead engineer to estimate mercury emissions from stationary sources in Northern Mexico. Major potential sources of mercury emissions include solid- and liquid-fueled power plants, cement kilns co-firing hazardous waste, and non-ferrous metal smelters. Emission estimates were provided for approximately eighty of these sources located in Northern Mexico. Coordinated efforts of two Mexican subcontractors, located in Mexico City and Hermosillo, to obtain process throughput data for each source included in the inventory.

Translation of U.S. EPA Scrap Tire Combustion Emissions Estimation Document – Mexico. Evaluated the Translated a U.S. EPA scrap tire combustion emissions estimation document from English to Spanish for use by Latin American environmental professionals.

Environmental Audit of Aluminum Production Facilities – Venezuela. Evaluated the capabilities of existing air, wastewater and solid/hazardous waste control systems used by the aluminum industry in eastern Venezuela. This industry will be privatized in the near future. Estimated the cost to bring these control systems into compliance with air, wastewater and solid/hazardous waste standards recently promulgated in Venezuela. Also served as technical translator for team of U.S. environmental engineers involved in the due diligence assessment.

Assessment of Environmental Improvement Projects – Chile and Peru. Evaluated potential air, water, soil remediation and waste recycling projects in Lima, Peru and Santiago, Chile for feasibility study funding by the U.S. Trade and Development Agency. Project required onsite interaction with in-country decisionmakers (in Spanish). Projects recommended for feasibility study funding included: 1) an air quality technical support project for the Santiago, Chile region, and 2) soil remediation/metals recovery projects at two copper mine/smelter sites in Peru.

Air Pollution Control Training Course – Mexico. Conducted two-day Spanish language air quality training course for environmental managers of assembly plants in Mexicali, Mexico. Spanish-language course manual prepared by Powers Engineering. Practical laboratory included training in use of combustion gas analyzer, flame ionization detector (FID), photoionization detector (PID), and occupational sampling.

Stationary Source Emissions Inventory – Mexico. Developed a comprehensive air emissions inventory for stationary sources in Nogales, Sonora. This project requires frequent interaction with Mexican state and federal environmental authorities. The principal Powers Engineering subcontractor on this project is a Mexican firm located in Hermosillo, Sonora.

VOC Measurement Program – Mexico. Performed a comprehensive volatile organic compound (VOC) measurements program at a health products fabrication plant in Mexicali, Mexico. An FID and PID were used to quantify VOCs from five processes at the facility. Occupational exposures were also measured. Worker exposure levels were above allowable levels at several points in the main assembly area.

Renewable Energy Resource Assessment Proposal – Panama. Translated and managed winning bid to evaluate wind energy potential in Panama. Direct interaction with the director of development at the national utility monopoly (IRHE) was a key component of this project.

Comprehensive Air Emissions Testing at Assembly Plant – Mexico. Project manager and field supervisor of emissions testing for particulates, NO_x, SO_2 and CO at turbocharger/air cooler assembly plant in Mexicali, Mexico. Source specific emission rates were developed for each point source at the facility during the test program. Translated test report into Spanish for review by the Mexican federal environmental agency (SEMARNAP).

Air Pollution Control Equipment Retrofit Evaluation – Mexico. Project manager and lead engineer for comprehensive evaluation of air pollution control equipment and industrial ventilation systems in use at assembly plant consisting of four major facilities. Equipment evaluated included fabric filters controlling blast booth emissions, electrostatic precipitator controlling welding fumes, and industrial ventilation systems controlling welding fumes, chemical cleaning tank emissions, and hot combustion gas emissions. Recommendations included modifications to fabric filter cleaning cycle, preventative maintenance program for the electrostatic precipitator, and redesign of the industrial ventilation system exhaust hoods to improve capture efficiency.

Comprehensive Air Emissions Testing at Assembly Plant – Mexico. Project manager and field supervisor of emissions testing for particulates, NO_x, SO_2 and CO at automotive components assembly plant in Acuña, Mexico. Source-specific emission rates were developed for each point source at the facility during the test program. Translated test report into Spanish.

Fluent in Spanish. Studied at the Universidad de Michoacán in Morelia, Mexico, 1993, and at the Colegio de España in Salamanca, Spain, 1987-88. Have lectured (in Spanish) on air monitoring and control equipment at the Instituto Tecnológico de Tijuana. Maintain contact with Comisión Federal de Electricidad engineers responsible for operation of wind and geothermal power plants in Mexico, and am comfortable operating in the Mexican business environment.

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Bill Powers, "*Environmental Problem Solving Itself Rapidly Through Lower Gas Costs*," Natural Gas & Electricity Journal, Vol. 26, Number 4, November 2009, pp. 9-14.

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EXHIBIT PE-03

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

OPENING COMMENTS OF SIERRA CLUB CALIFORNIA ON ALJ GAMSON'S QUESTIONS FROM THE SEPTEMBER 4, 2013 PREHEARING CONFERENCE

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Dated: September 30, 2013

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In accordance with the Assigned Commissioner's and Administrative Law Judge's Ruling Regarding Track 2 and Track 4 Schedules, Sierra Club California ("Sierra Club") respectfully submits the following comments in response to the questions presented by Administrative Law Judge Gamson at the September 4th, 2013 prehearing conference. Sierra Club repeats the questions and provides relevant answers after each question.

INTRODUCTION

In this track of the LTPP, the Commission has a historic opportunity to reshape the Southern California grid. The closure of SONGS raises reactive power/voltage support and potential generation issues. To determine the amount of need and the right mix of resources, the Commission will need to consider transmission solutions as well as generation. Excluding CAISO's 2013/2014 transmission studies from consideration creates a situation where the Commission may authorize unnecessary over-procurement which will be costly to ratepayers.[1] The most pressing need here is a solution that addresses the issues created by the SONGS closure, not a quick solution this fall or winter that may cause more harm than good. Authorization of new conventional generation could lead to unnecessary gas-fired generation

[1] Transmission and reactive power issues are addressed in the Prepared Opening Testimony of Bill Powers on Behalf of Sierra Club California

that will be around for another forty years creating excess air pollution and greenhouse gas emissions at a time when California has a mandates to reduce this pollution.

The Commission should not authorize procurement for neither Southern California Edison ("SCE") nor San Diego Gas & Electric ("SDG&E"). In addition to the testimony of Bill Powers submitted concurrently with these comments, the answers to the policy questions below show that no new procurement authorization is needed. SCE and SDG&E both request authorization of 500 MW of procurement for cumulative total of 1,000 MW. Consideration of the new California Energy Commission ("CEC") demand forecast by itself would eliminate any need because it shows a reduction in demand of 1213 MW (under the baseline forecast) in the LA Basin and even more in the adjusted forecast. Other resources that will reduce any determination of need include 745 MW of energy storage resources, 250-500 MW of distributed generation, hundreds of MW or more of uncommitted energy efficiency and 997 MW of demand response. Even if the full values of these numbers were not used to modify the need determination, the cumulative total more than offsets the requests for new authorization. However, if any need is determined, it should be filled by energy storage and preferred resources to be consistent with the loading order and to avoid exacerbating already unhealthy air quality in Southern California.

ANSWERS TO ALJ QUESTIONS

1) How much of the 1400-1800 MW authorized procurement in in the LA area should be assumed in Track 4?

The total amount of procurement authorized in Track 1 should be considered in Track 4. The Track 1 authorization of 1,800 MW addresses a subset of the same local capacity requirements being addressed in Track 4. In its testimony, California Independent System Operator ("CAISO") recognizes that the total amount of authorization should be considered in

Track 1. For example, in Table 13 CAISO subtracts out the total authorization of 1,800 MW when discussing the potential need. [2] SCE also makes the same assumption in its testimony.[3]

The Commission should also recognize that Track 1 authorized a very significant amount of procurement in the SCE local capacity area. This authorization should provide a cushion while the Commission analyzes all the necessary options, including transmission options. CAISO's request to delay procurement implicitly recognizes that despite claims to the contrary, there is no urgency to make a Track 4 decision this fall or winter.[4]

a) Does it matter what resources are procured?

Yes, the resource mix should maximize preferred and energy storage resources, because the San Onofre Nuclear Generating Station ("SONGS") did not emit greenhouse gases ("GHGs"). In order to conform with California's environmental and energy policies, SCE should be procuring local capacity resources that do not add to environmental challenges faced in the Los Angeles Air Basin. According to the South Coast Air Quality Management District, "a transition to zero- and near-zero emission technologies is necessary to meet 2023 and 2032 air quality standards and 2050 climate goals."[5] The Commission should recognize that to achieve the mandates of our air laws and California's climate goals, new fossil fuel generation cannot be built in the Los Angeles Basin. Rather than ignoring or attempting to bypass these constraints, the Commission should recognize limits to building conventional generation in this basin and plan accordingly. Eliminating fossil fuel generation is an important component of reducing the persistent, unhealthy air in the Los Angeles Basin. The Commission has the tools and ability to

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[2] Track 4 Testimony of Robert Sparks on Behalf of the California Independent System Operator Corporation, R.12-03-014 ("CAISO Testimony"), p. 26.
[3] Track 4 Testimony of Southern California Edison Company ("SCE Testimony"), p. 3, lns. 4-6.
[4] See CAISO Testimony, p. 30, lns. 1-5.
[5] South Coast Air Quality Management District. Final 2012 Air Quality Management Plan (Dec. 2012), p. 1-20.

set this area on a path towards healthy air by requiring the necessary amount of non-GHG emitting preferred and energy storage resources to meet the local capacity requirements.

b) Does it matter what the mix will be?

The resource mix matters, but the Commission eliminated an important source of information necessary to answer this question by excluding from consideration CAISO's 2013/2014 transmission planning. In its 2013/2014 transmission planning, CAISO plans to evaluate the appropriate mix of preferred resources to replace conventional generation.[6] CAISO recently released a report discussing a plan to address this very issue. The report entitled "Consideration of alternatives to transmission or conventional generation to address local needs in the transmission planning process," explains that in the SONGS local capacity area "transmission options will be pursued to complement non-conventional alternatives (i.e., preferred resources), to reduce the need for conventional generation . . . [T]he main focus of this effort with respect to the LA Basin and San Diego is to identify the volume of non-conventional alternatives and the needed performance attributes that could effectively address the local reliability needs in these two priority areas as part of a basket of resources."[7] CAISO also explains that they had planned to coordinate this information with Track 4. The decision should recognize the added value that CAISO's 2013/2014 transmission planning may provide and not authorize new conventional resources until this information is considered as part of the long term procurement planning ("LTPP") process. Alternatively, since this information will not be considered this fall, the decision should require the procurement of preferred and energy storage resources and require that these resources be procured to address local capacity requirements.

[6] CAISO, "Consideration of alternatives to transmission or conventional generation to address local needs in the transmission planning process" (Sept. 4, 2013), p. 4.
[7] Id.

2) Should anything in the Proposed Decision in the storage proceeding be considered in the Track 4 procurement?

All of the proposed procurement targets for SCE and San Diego Gas & Electric ("SDG&E") from the energy storage proceeding should be considered. The Proposed Decision ("PD") sets forth a cumulative total of 745 MW of energy storage to be procured in the SCE and SDG&E territories; all of this should be counted when determining resource need. The storage is apportioned to three categories: Transmission, Distribution and Customer-Side. Table 1 provides cumulative 2020 targets for these two Investor Owned Utilities ("IOUs").

Table 1. Proposed 2020 storage MW targets in Energy Storage Proposed Decision:[8]

Type	SCE MW	SDG&E MW	Total MW
Transmission	310	80	390
Distribution	185	55	240
Customer	85	30	115
Total	580	165	745

The Energy Storage PD does allow each IOU to shift up to 80% of the target between the Transmission and Distribution targets.[9] Both transmission and distribution-connected energy storage provide peaking services. The local capacity finding is inappropriately based on the extremely improbable ("Category D") double contingency of loss of two of SDG&E's three major transmission import pathways, the 500 kV Southwest Powerlink and the 500 kV Sunrise Powerlink, (N-1-1) on the hottest day in 10 years. In any case, it is reasonable to assume that all transmission and distribution-level energy storage will be available to meet peak needs under any

[8] Proposed Decision of Commissioner Peterman, Decision Adopting Energy Storage Procurement Framework and Design Program, R.10-12-007 ("Energy Storage PD") (Sept. 3, 2013), p. 15, Table 2.
[9] Energy Storage PD, p. 37.

limiting contingency. Customer-sited energy storage can also serve peak needs, though the provision of this service would likely depend on tariffs that value provision of energy during peak periods.

The Track 4 decision can ensure that all the energy storage procured pursuant to the energy storage decision is used to meet local capacity requirements in the San Onofre Nuclear Generating Station ("SONGS") local capacity area.[10] The Energy Storage PD creates a request for offers ("RFO") process for the procurement of this storage. According to the PD, "[t]he advantage of an RFO is that it enables the utilities to tailor a 'targeted' RFO to reflect their specific resource needs and criteria."[11] The Track 4 decision should increase the value of the energy storage being procured through the energy storage decision by requiring that energy storage be designed to meet local capacity requirements in the SONGS area. This will maximize the benefit of both decisions. In fact, the cost-effectiveness of the energy storage resources will be enhanced because these resources will be competing with conventional generation that is more expensive to procure and difficult to site in a congested urban area (due to expensive and scarce air credits).[12] Energy storage resources will play a key role in California's clean energy future, which requires a move away from fossil fuels, and depends on the integration of increasing amounts of renewables onto the grid. To achieve California's goal of an 80% reduction in carbon emissions by 2050, the amount of storage on the grid will have to increase

[10] The final decision in this case is scheduled for the Commission's October 3, 2013 meeting. These comments are based on the proposed decision. *See* Energy Storage PD.
[11] Energy Storage PD, p. 51.
[12] SCE Testimony, p. 13, lns 1-3.

dramatically.[13] Track 4 can take an important step in integrating energy storage into California's resource planning by the counting the energy storage that will be procured pursuant to the Energy Storage Proposed Decision, which may be finalized at the Commission meeting on October 3rd.

3) Are there any other updates to assumptions that should be considered?

Yes. The assumptions adopted by the Commission in the May 2013 Revised Scoping Ruling did not account for all preferred resources available. In addition, there have been new revisions to the CEC load forecast since the publication of the Revised Scoping Ruling. The Commission should consider these new updates in addition to resources that were previously overlooked. The following information shows that the procurement need is zero.

The Commission should rely on the latest CEC demand forecast, released in September 2013. The latest load forecast will reduce load in the LA Basin by 1213 MW (under the baseline forecast) or 2650 MW (under the adjusted forecast).[14] Using this load forecast rather than the now outdated 2012 forecast would eliminate any theoretical need in the SONGS area.

Energy efficiency estimates should be increased. The CEC forecast includes embedded committed energy efficiency programs, and the Commission then further reduces load by using the low-case estimate of incremental uncommitted energy projects in 2022. However, this adjustment is not sufficient. The Commission should use the mid-case assumption instead, as it is

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[13] *See* Cal. Energy Commission, Renewable Power in California: Status and Issues, CEC-150-2011-002 (Aug. 2011) pp. 52, 100; *see also* Rulemaking 10-12-007, Staff Summary, Energy Storage Procurement Workshop (January 14, 2013) p. 1 (quoting President Peevey's statement at the workshop: "I believe the Commission's energy storage policy is the bridge to our long-term future, not only 10 years from now, but 40 years from now and beyond. And we must start building that bridge or we will never reach our 2050 goals to reduce greenhouse gas emissions by 80% from 1990 levels.")

[14] California Energy Commission, Mid Case LSE and Balancing Authority – AAEE adjustment. (Sept. 20, 2013) Retrieved September 24, 2013 from http://www.energy.ca.gov/2013_energypolicy/documents/2013-10-01_workshop/spreadsheets/Mid_Case_LSE_and_Balancing_Authority-AAEE_adjustment.xlsx; California Energy Commission, Mid Case LSE and Balancing Authority – baseline. (Sept. 19, 2013) Retrieved September 24, 2013 from http://www.energy.ca.gov/2013_energypolicy/documents/2013-10-01_workshop/spreadsheets/Mid_Case_LSE_and_Balancing_Authority-baseline.xlsx.

more likely to occur. SDG&E uses the mid-case uncommitted energy efficiency amount in its Track 4 technical study.[15] The CEC estimates a total of 3,103 MW of incremental uncommitted energy efficiency in 2022 amongst the three IOUs.[16] SCE's share of that figure amounts to 1,520 MW, and SDG&E's share amounts to 248 MW.[17] In comparison, Attachment A of the Revised Scoping Ruling derives the amount of incremental uncommitted energy efficiency in the LA Basin and San Diego areas from an initial estimate of 973 MW of incremental uncommitted energy efficiency in SCE's territory and 187 MW in SDG&E's territory.[18] These amounts are 547 MW (SCE) and 61 MW (SDG&E) lower than the CEC estimates above. It is important to note that uncommitted energy efficiency programs are generally considered "reasonably likely to occur given current overall strategies,"[19] and the Commission should at the very least consider a those programs in Track 4, in addition to other energy efficiency programs that the Commission has approved as well as new codes and standards.[20]

Distributed generation programs that could reduce load by an estimated 250-500 MW are not considered in this track, but should be. SDG&E and SCE are subject to SB 1122, which sets a statewide requirement for 250 MW of procurement from small-scale bioenergy producers.[21]

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[15] Anderson, Robert B. August 2013. Prepared Track 4 Direct Testimony of San Diego Gas & Electric Company (U 902 E) ("SDG&E Testimony"), p. 6, lns 11-12.
[16] California Energy Commission. September 2012. Energy Efficiency Adjustments for a Managed Forecast: Estimates of Incremental Uncommitted Energy Savings Relative to the California Energy Demand Forecast 2012-2022, p. 2. Retrieved September 25, 2013 from http://www.energy.ca.gov/2012_energypolicy/documents/demand-forecast/Memorandum_IUEE-CED2011.pdf.
[17] D.12-05-035, p. 79.
[18] Revised Scoping Ruling, Attachment A, p. 4.
[19] Kavalec, Chris, Nicholas Fugate, Bryan Alcorn, Mark Ciminelli, Asish Gautam, Kate Sullivan, and Malachi Weng‑Gutierrez, 2013. California Energy Demand 2014‑2024 Preliminary Forecast, Volume 1: Statewide Electricity Demand, End‑User Natural Gas Demand, and Energy Efficiency. California Energy Commission, Electricity Supply Analysis Division. Publication Number: CEC‑200‑2013‑004‑SD‑V1, p. 70.
[20] The Natural Resources Defense Council provides a more expansive accounting of the available energy efficiency savings.
[21] California Public Utilities Commission. SB 1122: Bioenergy Feed-in Tariff. Retrieved September 24, 2013 from http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/SB_1122_Bioenergy_Feed-in_Tariff.htm.

SDG&E and SCE's shares of this 250 MW are 24.7 MW and 114.5 MW respectively.[22] The Commission allowed SDG&E and SCE to transfer some of their procurement of rooftop solar PV to the RAM program. These transfers amounted to 250 MW-dc (200 MW-ac)[23] from SCE's PV program and 74 MW-dc from SDG&E's PV program.[24] These transfers left 225 MW-dc and 26 MW-dc in SCE and SDG&E's IOU PV programs, respectively, which also contribute to the total amount of wholesale distributed generation available to reduce need. The IOUs are also subject to SB 32, which increases the size of projects eligible for Feed-in Tariffs to 3 MW.[25] A 2012 Commission decision allocated 226 MW of the 750 MW under the SB 32 Feed-in Tariff program cap to SCE, and 48.8 MW-ac of 750 MW to SDG&E.[26] RAM in SCE and SDG&E territories amounts to 878.4 MW-dc (723.4 MW in SCE territory and 155 MW in SDG&E territory), and includes distributed generation (generally solar projects).[27]

In Table 1 below, we sum these resources and arrive at a total of 522.8 MW (min) to 1540.4 MW (max) of wholesale renewable distributed generation. The minimum includes only the resources from the IOU PV and SB 32 Feed-in Tariff programs, as a conservative estimate, while the maximum includes all programs described above. Assuming an effective capacity equal to the average of SDG&E and SCE's peak demand impact factors in Attachment A of the Revised Scoping Ruling,[28] need would be reduced by 237.9 MW (min) to 702.4 MW (max). Applying the CEC's "reliable capacity" factor equivalent to net qualifying ("NQC") for

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[22] SCE is responsible for 49% of capacity held by IOUs, and SDG&E is responsible for 8%. *See* D.12-05-035, p. 79.
[23] Conversion factor from MW-dc to MW-ac is 0.080. See: U.S. Energy Information Administration, Utility-scale installations (> 1 MW) lead solar photovoltaic growth, October 31, 2012. See: http://www.eia.gov/todayinenergy/detail/2012-10-31/utility-scale-installations-lead-solar-photovoltaic-growth
[24] D.12-02-035, p. 2; D.12-02-002, p. 4.
[25] California Public Utilities Commission. Summary of Feed-In Tariffs. Retrieved September 24, 2013 from http://www.cpuc.ca.gov/PUC/energy/Renewables/feedintariffssum.htm.
[26] D.12-05-035, p. 74
[27] D.12-02-035, p. 27; D.12-02-002, p. 17.
[28] Revised Scoping Ruling and Memo of the Assigned Commissioner and Administrative Law Judge ("Revised Scoping Ruling") (May 21, 2013), Attachment A, p. 9.

wholesale distributed PV resources of 0.85, need would be reduced by 444 MW (min) to 1,309 MW (max).[29] If energy storage resources from the recent proposed decision in the energy storage proceeding are included, need could be reduced by 592.9 MW – 1447.4 MW.[30] The Commission should incorporate these resources into the assumptions, as these programs are being implemented and the resources procured will meet need in the areas affected by the SONGS closure. Including these resources, as shown in Table 2, will eliminate need.

Table 2. Capacity of Wholesale Renewable Distributed Generation Programs

Wholesale Renewable Distributed Generation Programs in Southern California IOU Service Territories				
	Program	SCE	SDG&E	Total So Cal
	IOU PV	225.0	23.0	248.0
	FIT (SB 32)	226.0	48.8	274.8
	FIT (SB 1122)	122.5	20.0	142.5
	RAM	723.4	155.0	878.4
	Total RDG	1296.9	246.8	1543.7
46%	Effective Capacity	590.1	112.3	702.4
	Total Storage	580.0	165.0	745.0
	Combined Capacity	1170.1	277.3	1447.4
	Minimum RDG	451.0	71.8	522.8
46%	Effective Capacity	205.2	32.7	237.9
	Distributed Storage	270	85	355
	Combined Capacity	475.2	117.7	592.9

Lastly, the assumptions in the Revised Scoping Ruling underestimate the amount of demand response available to meet need in the SONGS reliability area. The Revised Scoping Ruling divides demand response into first and second contingencies, but this approach

[29] CEC. Summer 2012 Electricity Supply and Demand Outlook (May 2012), Appendix B, p. B-2 – B.4. Retrieved from http://www.energy.ca.gov/2012publications/CEC-200-2012-003/CEC-200-2012-003.pdf.
[30] *See* Proposed Decision of Commissioner Peterman, Decision Adopting Energy Storage Procurement Framework and Design Program (Sept. 3, 2013), p. 15.

improperly excludes 997 MW of second contingency demand response when determining need.[31] Sierra Club recommends that this "second contingency" demand be subtracted from any identified need, because all demand response resources are intended to be deployed on very hot days to reduce stress on the grid. Very hot, high demand days are forecast at least a day or two in advance by CAISO. CAISO issues Flex Alerts when the forecast indicates that demand may be sufficiently high to strain the grid the following day. Therefore, all demand response resources that are under contract, regardless of whether they can be deployed in 30 minutes or not, should be fully counted as LCR capacity to meet the critical contingency. This treatment of demand response resources will substantially reduce the LCR need by 997 MW in 2022.[32] Since this demand response was not included in the model, it should be subtracted from any identified load.

4) What is the appropriate timeline for new resource procurement that may be authorized in Track 4? Do some resources have to come on earlier than others? (Can also be locational question)

The preferred and energy storage resources can be put on the system faster and earlier than conventional generation, and thus, should be prioritized. In addition, the Energy Storage PD sets 2020 as the ultimate target for very significant energy storage procurement. Emphasizing the deployment of preferred and energy storage resources is the least regrets strategy from a procurement as well as an environmental perspective.

The timeline depends on when the need exists, if it ever does. The 2018 need appears to be created by assumption the retirement of aging once-through cooling ("OTC") power plants and non-OTC power plants such as the 640 MW Etiwanda plant in SCE territory and the 188

[31] Revised Scoping Ruling, Attachment A, p. 7.
[32] *Id*.

MW Cabrillo II combustion turbines in San Diego.[33] If these retirements did not occur then, the timeline will be extended. Moreover, the mandate of the authorized procurement should be to avoid new fossil-fuel procurement. It may be appropriate to delay an OTC retirement, such as Encina, in addition to delaying the non-OTC retirements, for a limited time to bridge the gap until other preferred and energy storage resources are added to the system.

5) Should there be any contingency plans in case certain resources do not materialize in a timely manner?

No, the reliability situation in the SONGS area is stable. California's energy and environment policies are succeeding in placing an unprecedented amount of preferred resources on the system, and will do the same for energy storage over the next seven years. The LTPP occurs biennally; it provides ample opportunity to make adjustments along the way. For example, Track 1 filled a local capacity need that was identified in the Los Angeles area. WithTrack 1, the 33% RPS, the energy storage PD, the on-going commitment to energy efficiency, the concerted efforts to better incorporate and account for demand response and the trend towards lower demand forecasts, it is clear that there is no need for contingencies. If anything, there is significant potential for over-procurement.

Despite pleas to the contrary, the situation is anything but dire. The actual load demand trend is flat. There has been no net peak load growth in Southern California over the last eight summers. The 1-hour peak demand trend in SCE territory is shown in Figure 1. The 1-hour peak demand trend in SDG&E territory is shown in Figure 2.

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[33] Energy Justice Network. 2008. Etiwanda Generating Station. Retrieved September 26, 2013 from http://www.energyjustice.net/map/displayfacility-63977.htm; Quail Brush Genco. Re: Quail Brush Generation Project (11-AFC-03) Further Response to HomeFed Fanita Rancho Data Requests 85 through 105 (Jan. 11, 2013), p. 3.

Figure 1. 1-hour peak demand trend in SCE territory, 2006 - 2013

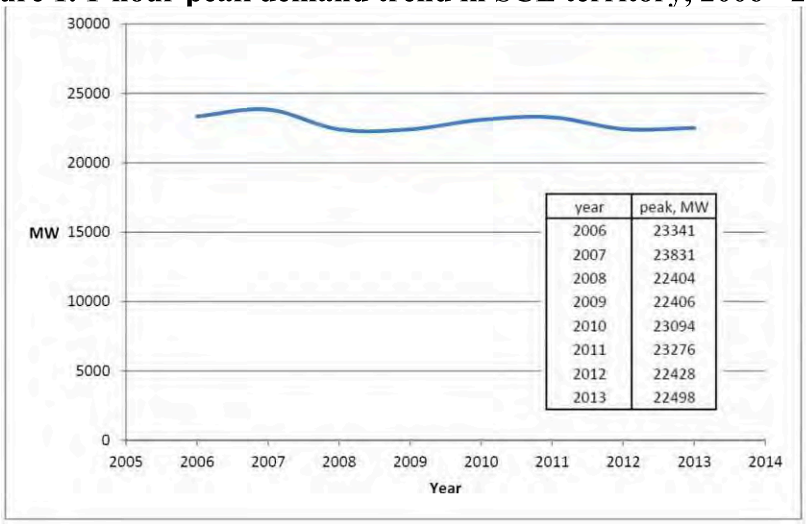
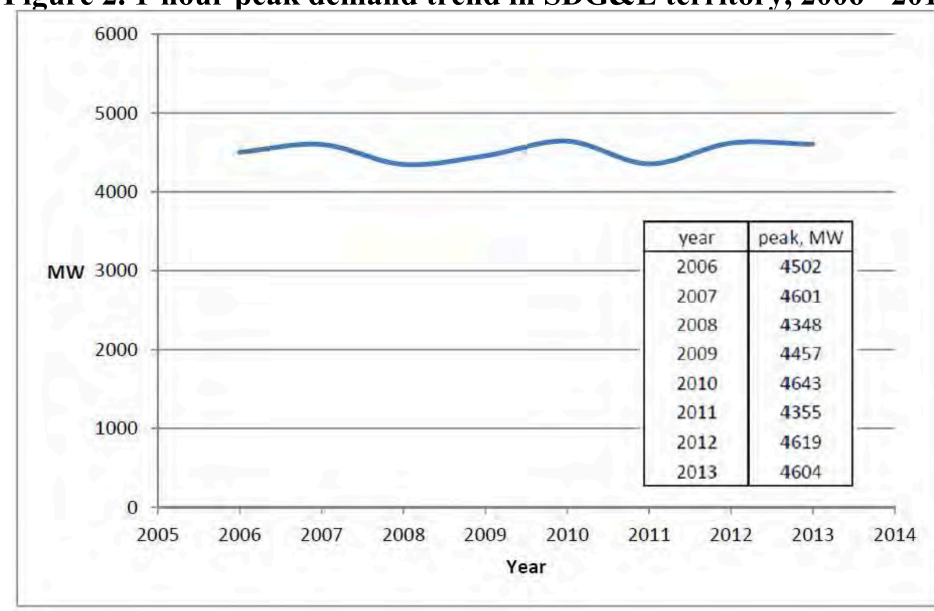
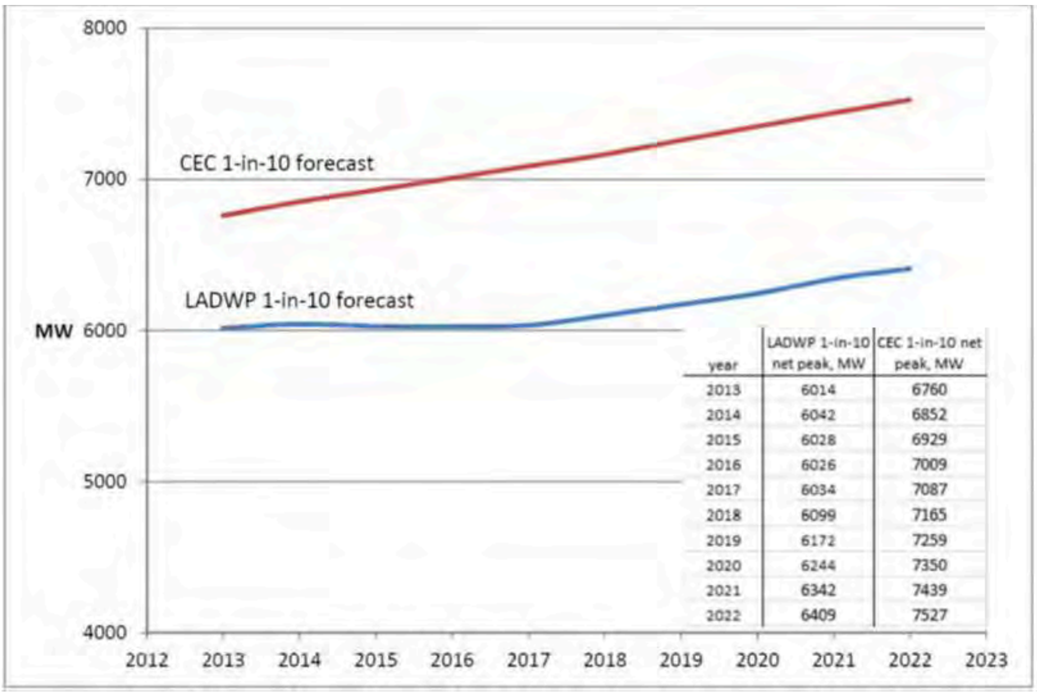


Figure 2. 1-hour peak demand trend in SDG&E territory, 2006 - 2013



The Los Angeles Department of Water and Power ("LADWP") service territory is surrounded by SCE's service territory and has experienced the same flat peak growth phenomenon in the last eight years. However, in contrast to the CEC 2012-2022 peak load growth projection used by all parties in the Track 4 proceeding, LADWP projects relatively flat peak load growth in the 2012 – 2022 time frame. The CEC peak load forecast for the LADWP in the 2012 – 2022 time frame is included in Figure 3 as well, to show the dramatic difference between LADWP's own peak load forecast and the CEC's peak load forecast for LADWP. LADWP projects a 2022 net 1-in-10 year peak load of 6,409 MW. LADWP does not forecast returning to its all-time peak of 6,177 MW, recorded on September 27, 2010, until 2020.[34] The CEC projects a net 1-in-10 year LADWP peak load in 2022 of 7,527 MW. This is over 1,100 MW greater than LADWP's own 1-in-10 year peak forecast.

Figure 3. LADWP 2012-2022 Load Forecast versus CEC 2012-2022 Load Forecast for LADWP[35]



SCE identifies the Johanna & Santiago areas as places where load growth could affect local capacity, but SCE proposes to mitigate these contingencies by initiating a preferred resources pilot.[36] This pilot is designed to "manage load to zero net growth in the Johanna-Santiago vicinity -- unmanaged growth is expected to be about 25 MW/Year."[37] Rather than building new power plants, managing load growth is the better approach to addressing local capacity concerns. This is an important step because SCE has not procured Preferred Resources

[34] LADWP. "LADWP Power System Registers Highest Ever Customer Demand for Electricity; Continued Conservation Encouraged for Monday Night, All Day Tuesday" (Sept. 27, 2010). Retrieved from http://www.ladwpnews.com/go/doc/1475/907083/LADWP-Heat-Update.
[35] LADWP. 2012 Ten-Year Transmission Assessment, (Dec. 2012), Table 3, p. 10.
[36] SCE Testimony, p. 49, lns 3-6.
[37] SCE Presentation, Preferred Resource Pilot Targeted Scope (Sept. 24, 2013) (attached as Exhibit A), Slide 2. This load growth estimate is also questionable given the nature peak load growth in Southern California.

"to meet reliability needs."[38] This change in approach will increase "the amounts of Preferred Resources, while ensuring grid stability and resiliency."[39] This is consistent with the loading order and will not add to the air pollution issues in Southern California.

6) Should the Commission consider methods to reduce potential market power in SONGS area for gas fired resources? If so, what?

Yes. The best method for reducing market power in the SONGS area is promoting and procuring preferred and energy storage resources. The market power issue only arises if the Commission insists on pursuing a natural gas strategy to fill procurement gaps, if any. The repowering of the uniquely-situated OTC plants could create market power issues. Rather than a minimum and maximum amount of any new procurement to be filled by gas resources, the Commission should fill all need with preferred and energy storage resources that do not raise market power issues. This approach also reduces the environmental impacts of any new procurement and eliminates issues related to siting new polluters in this severely overburdened air basin.

7) If you are recommending preferred resources and storage to fill need, indicate how the attributes of those resources help meet LCR need.

Targeted energy efficiency is particularly effective in the context of local capacity requirements because the main driver of peak demand is air conditioning. Energy efficiency programs targeted at air conditioning and home insulation, among others, would directly address the driver of peak demand.

Energy storage fills need because it allows for the balancing of loads, maintains stable power and addresses the so-called "duck chart" issue. In addition to battery storage, other forms of storage, such as ice cooling in buildings, can also reduce energy use at peak times.

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[38] SCE Testimony, p. 49, ln 17.
[39] *Id*, lns 19-20.

The locational benefit of the preferred and energy storage resources may also contribute to reducing LCR. A premium should be placed on siting these resources in effective locations.

CONCLUSION

For the foregoing reasons, the Commission should not authorize procurement in Track 4.

Respectfully submitted,

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WILLIAM B. ROSTOV

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Attorneys for
SIERRA CLUB CALIFORNIA

Dated: September 30, 2013

EXHIBIT PE-04

INTERVALS	INTERVALE	LOAD_TYPI	OPR_DT	OPR_HR	OPR_INTEF	MARKET_R	TAC_AREA_	LABEL	XML_DATA	POS	MW	EXECUTION
2014-09-1!	2014-09-1!	0	9/15/2014	6	0	ACTUAL	CA ISO-TAC	Total Actua	SYS_FCST_	3	25530	ACTUAL
2014-09-16	2014-09-16	0	9/15/2014	24	0	ACTUAL	CA ISO-TAC	Total Actua	SYS_FCST_	3	31079	ACTUAL
2014-09-1!	2014-09-1!	0	9/15/2014	11	0	ACTUAL	CA ISO-TAC	Total Actua	SYS_FCST_	3	36278	ACTUAL
2014-09-1!	2014-09-1!	0	9/15/2014	12	0	ACTUAL	CA ISO-TAC	Total Actua	SYS_FCST_	3	38552	ACTUAL
2014-09-16	2014-09-16	0	9/15/2014	23	0	ACTUAL	CA ISO-TAC	Total Actua	SYS_FCST_	3	34761	ACTUAL
2014-09-1!	2014-09-1!	0	9/15/2014	13	0	ACTUAL	CA ISO-TAC	Total Actua	SYS_FCST_	3	40395	ACTUAL
2014-09-1!	2014-09-1!	0	9/15/2014	16	0	ACTUAL	CA ISO-TAC	Total Actua	SYS_FCST_	3	44320	ACTUAL
2014-09-1!	2014-09-1!	0	9/15/2014	4	0	ACTUAL	CA ISO-TAC	Total Actua	SYS_FCST_	3	24539	ACTUAL
2014-09-1!	2014-09-1!	0	9/15/2014	5	0	ACTUAL	CA ISO-TAC	Total Actua	SYS_FCST_	3	24727	ACTUAL
2014-09-1!	2014-09-16	0	9/15/2014	17	0	ACTUAL	CA ISO-TAC	Total Actua	SYS_FCST_	3	44671	ACTUAL
2014-09-16	2014-09-16	0	9/15/2014	22	0	ACTUAL	CA ISO-TAC	Total Actua	SYS_FCST_	3	38762	ACTUAL
2014-09-1!	2014-09-1!	0	9/15/2014	2	0	ACTUAL	CA ISO-TAC	Total Actua	SYS_FCST_	3	25710	ACTUAL
2014-09-1!	2014-09-1!	0	9/15/2014	15	0	ACTUAL	CA ISO-TAC	Total Actua	SYS_FCST_	3	43845	ACTUAL
2014-09-16	2014-09-16	0	9/15/2014	18	0	ACTUAL	CA ISO-TAC	Total Actua	SYS_FCST_	3	44636	ACTUAL
2014-09-16	2014-09-16	0	9/15/2014	19	0	ACTUAL	CA ISO-TAC	Total Actua	SYS_FCST_	3	43257	ACTUAL
2014-09-16	2014-09-16	0	9/15/2014	20	0	ACTUAL	CA ISO-TAC	Total Actua	SYS_FCST_	3	43081	ACTUAL
2014-09-1!	2014-09-1!	0	9/15/2014	8	0	ACTUAL	CA ISO-TAC	Total Actua	SYS_FCST_	3	29629	ACTUAL
2014-09-16	2014-09-16	0	9/15/2014	21	0	ACTUAL	CA ISO-TAC	Total Actua	SYS_FCST_	3	41800	ACTUAL
2014-09-1!	2014-09-1!	0	9/15/2014	1	0	ACTUAL	CA ISO-TAC	Total Actua	SYS_FCST_	3	27264	ACTUAL
2014-09-1!	2014-09-1!	0	9/15/2014	3	0	ACTUAL	CA ISO-TAC	Total Actua	SYS_FCST_	3	24777	ACTUAL
2014-09-1!	2014-09-1!	0	9/15/2014	7	0	ACTUAL	CA ISO-TAC	Total Actua	SYS_FCST_	3	27900	ACTUAL
2014-09-1!	2014-09-1!	0	9/15/2014	10	0	ACTUAL	CA ISO-TAC	Total Actua	SYS_FCST_	3	33789	ACTUAL
2014-09-1!	2014-09-1!	0	9/15/2014	14	0	ACTUAL	CA ISO-TAC	Total Actua	SYS_FCST_	3	42385	ACTUAL
2014-09-1!	2014-09-1!	0	9/15/2014	9	0	ACTUAL	CA ISO-TAC	Total Actua	SYS_FCST_	3	31784	ACTUAL
2014-09-1!	2014-09-1!	0	9/15/2014	3	0	ACTUAL	PGE-TAC	Total Actua	SYS_FCST_	3	10297	ACTUAL
2014-09-16	2014-09-16	0	9/15/2014	19	0	ACTUAL	PGE-TAC	Total Actua	SYS_FCST_	3	16370	ACTUAL
2014-09-1!	2014-09-1!	0	9/15/2014	11	0	ACTUAL	PGE-TAC	Total Actua	SYS_FCST_	3	14097	ACTUAL
2014-09-1!	2014-09-1!	0	9/15/2014	15	0	ACTUAL	PGE-TAC	Total Actua	SYS_FCST_	3	16337	ACTUAL
2014-09-16	2014-09-16	0	9/15/2014	23	0	ACTUAL	PGE-TAC	Total Actua	SYS_FCST_	3	13469	ACTUAL
2014-09-1!	2014-09-1!	0	9/15/2014	4	0	ACTUAL	PGE-TAC	Total Actua	SYS_FCST_	3	10406	ACTUAL
2014-09-1!	2014-09-1!	0	9/15/2014	14	0	ACTUAL	PGE-TAC	Total Actua	SYS_FCST_	3	15767	ACTUAL
2014-09-1!	2014-09-16	0	9/15/2014	17	0	ACTUAL	PGE-TAC	Total Actua	SYS_FCST_	3	16961	ACTUAL
2014-09-16	2014-09-16	0	9/15/2014	18	0	ACTUAL	PGE-TAC	Total Actua	SYS_FCST_	3	16855	ACTUAL
2014-09-16	2014-09-16	0	9/15/2014	21	0	ACTUAL	PGE-TAC	Total Actua	SYS_FCST_	3	15951	ACTUAL

2014-09-16	2014-09-16	0	9/15/2014	20	0	ACTUAL	PGE-TAC	Total Actua	SYS_FCST_/	3	16286	ACTUAL
2014-09-16	2014-09-16	0	9/15/2014	24	0	ACTUAL	PGE-TAC	Total Actua	SYS_FCST_/	3	12163	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	1	0	ACTUAL	PGE-TAC	Total Actua	SYS_FCST_/	3	11130	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	12	0	ACTUAL	PGE-TAC	Total Actua	SYS_FCST_/	3	14682	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	13	0	ACTUAL	PGE-TAC	Total Actua	SYS_FCST_/	3	15097	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	5	0	ACTUAL	PGE-TAC	Total Actua	SYS_FCST_/	3	10513	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	6	0	ACTUAL	PGE-TAC	Total Actua	SYS_FCST_/	3	10749	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	9	0	ACTUAL	PGE-TAC	Total Actua	SYS_FCST_/	3	13127	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	10	0	ACTUAL	PGE-TAC	Total Actua	SYS_FCST_/	3	13398	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	16	0	ACTUAL	PGE-TAC	Total Actua	SYS_FCST_/	3	16659	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	7	0	ACTUAL	PGE-TAC	Total Actua	SYS_FCST_/	3	11882	ACTUAL
2014-09-16	2014-09-16	0	9/15/2014	22	0	ACTUAL	PGE-TAC	Total Actua	SYS_FCST_/	3	14803	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	2	0	ACTUAL	PGE-TAC	Total Actua	SYS_FCST_/	3	10576	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	8	0	ACTUAL	PGE-TAC	Total Actua	SYS_FCST_/	3	12629	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	12	0	ACTUAL	SCE-TAC	Total Actua	SYS_FCST_/	3	19620	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	5	0	ACTUAL	SCE-TAC	Total Actua	SYS_FCST_/	3	11778	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	9	0	ACTUAL	SCE-TAC	Total Actua	SYS_FCST_/	3	15279	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	6	0	ACTUAL	SCE-TAC	Total Actua	SYS_FCST_/	3	12227	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	16	0	ACTUAL	SCE-TAC	Total Actua	SYS_FCST_/	3	22820	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	15	0	ACTUAL	SCE-TAC	Total Actua	SYS_FCST_/	3	22738	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	14	0	ACTUAL	SCE-TAC	Total Actua	SYS_FCST_/	3	21956	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	13	0	ACTUAL	SCE-TAC	Total Actua	SYS_FCST_/	3	20832	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	3	0	ACTUAL	SCE-TAC	Total Actua	SYS_FCST_/	3	12004	ACTUAL
2014-09-16	2014-09-16	0	9/15/2014	20	0	ACTUAL	SCE-TAC	Total Actua	SYS_FCST_/	3	22187	ACTUAL
2014-09-16	2014-09-16	0	9/15/2014	19	0	ACTUAL	SCE-TAC	Total Actua	SYS_FCST_/	3	22272	ACTUAL
2014-09-16	2014-09-16	0	9/15/2014	22	0	ACTUAL	SCE-TAC	Total Actua	SYS_FCST_/	3	19907	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	11	0	ACTUAL	SCE-TAC	Total Actua	SYS_FCST_/	3	18167	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	10	0	ACTUAL	SCE-TAC	Total Actua	SYS_FCST_/	3	16688	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	2	0	ACTUAL	SCE-TAC	Total Actua	SYS_FCST_/	3	12583	ACTUAL
2014-09-15	2014-09-16	0	9/15/2014	17	0	ACTUAL	SCE-TAC	Total Actua	SYS_FCST_/	3	22836	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	1	0	ACTUAL	SCE-TAC	Total Actua	SYS_FCST_/	3	13408	ACTUAL
2014-09-16	2014-09-16	0	9/15/2014	21	0	ACTUAL	SCE-TAC	Total Actua	SYS_FCST_/	3	21424	ACTUAL
2014-09-16	2014-09-16	0	9/15/2014	23	0	ACTUAL	SCE-TAC	Total Actua	SYS_FCST_/	3	17715	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	8	0	ACTUAL	SCE-TAC	Total Actua	SYS_FCST_/	3	13931	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	4	0	ACTUAL	SCE-TAC	Total Actua	SYS_FCST_/	3	11719	ACTUAL

2014-09-16	2014-09-16	0	9/15/2014	24	0	ACTUAL	SCE-TAC	Total Actua	SYS_FCST_	3	15772	ACTUAL
2014-09-16	2014-09-16	0	9/15/2014	18	0	ACTUAL	SCE-TAC	Total Actua	SYS_FCST_	3	22987	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	7	0	ACTUAL	SCE-TAC	Total Actua	SYS_FCST_	3	13192	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	13	0	ACTUAL	SDGE-TAC	Total Actua	SYS_FCST_	3	4373	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	10	0	ACTUAL	SDGE-TAC	Total Actua	SYS_FCST_	3	3637	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	7	0	ACTUAL	SDGE-TAC	Total Actua	SYS_FCST_	3	2777	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	5	0	ACTUAL	SDGE-TAC	Total Actua	SYS_FCST_	3	2393	ACTUAL
2014-09-16	2014-09-16	0	9/15/2014	21	0	ACTUAL	SDGE-TAC	Total Actua	SYS_FCST_	3	4344	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	3	0	ACTUAL	SDGE-TAC	Total Actua	SYS_FCST_	3	2432	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	2	0	ACTUAL	SDGE-TAC	Total Actua	SYS_FCST_	3	2505	ACTUAL
2014-09-16	2014-09-16	0	9/15/2014	20	0	ACTUAL	SDGE-TAC	Total Actua	SYS_FCST_	3	4519	ACTUAL
2014-09-16	2014-09-16	0	9/15/2014	24	0	ACTUAL	SDGE-TAC	Total Actua	SYS_FCST_	3	3086	ACTUAL
2014-09-16	2014-09-16	0	9/15/2014	19	0	ACTUAL	SDGE-TAC	Total Actua	SYS_FCST_	3	4519	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	16	0	ACTUAL	SDGE-TAC	Total Actua	SYS_FCST_	3	4736	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	14	0	ACTUAL	SDGE-TAC	Total Actua	SYS_FCST_	3	4563	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	12	0	ACTUAL	SDGE-TAC	Total Actua	SYS_FCST_	3	4166	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	6	0	ACTUAL	SDGE-TAC	Total Actua	SYS_FCST_	3	2508	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	1	0	ACTUAL	SDGE-TAC	Total Actua	SYS_FCST_	3	2677	ACTUAL
2014-09-15	2014-09-16	0	9/15/2014	17	0	ACTUAL	SDGE-TAC	Total Actua	SYS_FCST_	3	4769	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	11	0	ACTUAL	SDGE-TAC	Total Actua	SYS_FCST_	3	3939	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	8	0	ACTUAL	SDGE-TAC	Total Actua	SYS_FCST_	3	3016	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	9	0	ACTUAL	SDGE-TAC	Total Actua	SYS_FCST_	3	3320	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	4	0	ACTUAL	SDGE-TAC	Total Actua	SYS_FCST_	3	2371	ACTUAL
2014-09-16	2014-09-16	0	9/15/2014	18	0	ACTUAL	SDGE-TAC	Total Actua	SYS_FCST_	3	4692	ACTUAL
2014-09-16	2014-09-16	0	9/15/2014	22	0	ACTUAL	SDGE-TAC	Total Actua	SYS_FCST_	3	3978	ACTUAL
2014-09-16	2014-09-16	0	9/15/2014	23	0	ACTUAL	SDGE-TAC	Total Actua	SYS_FCST_	3	3512	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	15	0	ACTUAL	SDGE-TAC	Total Actua	SYS_FCST_	3	4668	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	1	0	ACTUAL	VEA-TAC	Total Actua	SYS_FCST_	3	49	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	3	0	ACTUAL	VEA-TAC	Total Actua	SYS_FCST_	3	44	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	9	0	ACTUAL	VEA-TAC	Total Actua	SYS_FCST_	3	58	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	10	0	ACTUAL	VEA-TAC	Total Actua	SYS_FCST_	3	66	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	14	0	ACTUAL	VEA-TAC	Total Actua	SYS_FCST_	3	99	ACTUAL
2014-09-16	2014-09-16	0	9/15/2014	19	0	ACTUAL	VEA-TAC	Total Actua	SYS_FCST_	3	96	ACTUAL
2014-09-16	2014-09-16	0	9/15/2014	21	0	ACTUAL	VEA-TAC	Total Actua	SYS_FCST_	3	81	ACTUAL
2014-09-15	2014-09-15	0	9/15/2014	2	0	ACTUAL	VEA-TAC	Total Actua	SYS_FCST_	3	46	ACTUAL

EXHIBIT PE-05

California ISO
Shaping a Renewed Future

California ISO Peak Load History
1998 through 2013

Year	Megawatts at Peak Load*	Date	Time
1998	44,659	August 12	14:30
1999	45,884	July 12	16:52
2000	43,784	August 16	15:17
2001	41,419	August 7	16:17
2002	42,441	July 10	15:01
2003	42,689	July 17	15:22
2004	45,597	September 8	16:00
2005	45,431	July 20	15:22
2006	50,270	July 24	14:44
2007	48,615	August 31	15:27
2008	46,897	June 20	16:21
2009	46,042	September 3	16:17
2010	47,350	August 25	16:20
2011	45,545	September 7	16:30
2012	46,846	August 13	15:53
2013	45,097	June 28	16:54

* This value is an instantaneous MW value at the time specified in the Time column.

EXHIBIT PE-06

News Release

For immediate release | **October 20, 2014 Media Hotline 888.516.6397**

CORRECTED Version: the drought peak was “hourly” not “instantaneous” in paragraph eight.

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California ISO: challenging 2014 summer but reliability held firm

Drought, heat waves and fires make for busy grid operations, but reliability maintained

FOLSOM, Calif. The California Independent System Operator Corporation (ISO) grid operators managed reliable electricity delivery this summer through major wildfires, historic drought conditions and heat waves.

This summer's highest level of demand reached 45,090 megawatts at 4:53 p.m. on September 15, 2014. This compares to 45,097 megawatts set on June 28, 2013 and 46,846 megawatts on August 13, 2012. The ISO's highest peak on record is 50,270 megawatts on July 24, 2006. On a local level, southern California set new demand records that underscore the impact from above normal hot temperatures recorded during the summer, especially along the coast. San Diego Gas & Electric area experienced record use on Monday, September 15 and then topped that on September 16 with an all-time record demand of 4,895 megawatts. The standing record peak was 4,684 megawatts set on September 27, 2010.

Southern California Edison area also experienced heavy loads reaching 23,266 megawatts on September 15. This was just shy of the area's all-time peak of 23,388 megawatts set on September 7, 2011.**

Meanwhile, one of the ISO's newest participating transmission owners, Valley Electric Association of Pahrump, Nevada, which serves a 6,800 square mile area south of Las Vegas and a sliver of California, set a new demand record of 120 megawatts on July 1, 2014. No matter the conditions, the ISO's main objective is to keep the power flowing to the nearly 30 million consumers we serve,said Eric Schmitt, ISO's Vice President, Operations. We had challenging drought conditions that limited hydro electricity production, hotter than normal temperatures and wildfires that threatened high-voltage power lines. Yet, grid operators working round the clock overcame those challenges to maintain reliability.

The ISO region, which covers most of California and a small part of Nevada, experienced numerous wildfires this year, but only a limited number threatened the high voltage grid. The San Diego County fires in mid-May triggered the year's only transmission emergency as 14 blazes threatened high-voltage lines serving the area as well as to the distribution lines that connect homes and businesses to electrical substations. Although there were several tense hours as the May 14 firestorms raged, grid operators from the ISO, working with San Diego Gas & Electric operators, managed to avoid electrical interruptions on the high-voltage grid.

In the 2014 Summer Loads and Resource Assessment, released in May, the ISO forecast we would have 1,300 megawatts to 1,669 megawatts less hydroelectricity available this summer. With historic drought conditions, there were 1,628 megawatts less of in-state hydro power this summer. The hourly peak hydro generation for the summer occurred on July 31, 2014 with5,016 megawatts.

Solar production hit a new peak on September 29, 2014 with 4,903 megawatts. The ISO has about 5,500 megawatts of utility solar resources connected to the grid. Meanwhile, wind facilities set a production record on April 12, 2014 with 4,768 megawatts about 5,900 megawatts of wind resources are interconnected. Counting all renewable resources (including small hydro, biomass, biogas, geothermal), the ISO has 15,226 megawatts of clean power on the grid.

The ISO is working with asset owners over the next several months to properly schedule maintenance on power plants and the transmission system without disrupting electricity delivery this winter and prepare for next summer.

**SCE does not serve the City of Pasadena, which is included in the ISO totals for the area.

EXHIBIT PE-07

STATE OF CALIFORNIA — Edmund G. Brown Jr., Governor

PUBLIC UTILITIES COMMISSION

505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

Commission Staff Report

Lessons Learned From Summer 2012 Southern California Investor Owned Utilities' Demand Response Programs
May 1, 2013

Performance of 2012 Demand Response programs of San Diego Gas and Electric Company and Southern California Edison Company: report on lessons learned, staff analysis, and recommendations for 2013-2014 program revisions in compliance with Ordering Paragraph 31 of Decision 13-04-017.

September 14, 2012 was considered a hot day (1-in-10 weather year condition[36]), however, SCE still did not dispatch their entire residential Summer Discount Plan participants. Instead, SCE only dispatched a portion of its participants for one hour of an event, resulting in a five consecutive one-hour events. On average, SCE received only 6.3 MW[37] for the event, which is a huge underperformance in comparison to RA forecast of 519 MW.[38] This raises the question that if SCE chose not to dispatch all of its Summer Discount Plan participants at the same event hour during a 1-in-10 weather year condition, under what circumstances SCE will dispatch its Summer Discount Plan to its full program capacity. The usefulness of the RA forecast is in question if the utility does not test a DR program to its full capacity. Should the RA forecast process be amended to include another Ex Ante forecast that is based on operational needs including optimal customer experience, and if so what would that entail?

D. Conclusion and Recommendations

Comparing the 2012 ex-post results to the 2012 RA load forecast is not an accurate method in determining DR program performance because the ex-post results are in response to operational needs which can be entirely different than resource planning needs. However, in 2012 the RA forecast was not tested to its full capacity. This raises the question of whether RA forecast should be changed to reflect both planning needs and operational needs. A working group that consist of the CPUC, CEC, CAISO, and the IOUs should be assembled to address the forecast needs (i.e. resource planning, operational planning) and input assumptions (i.e. growth rate, drop of rate) used for forecasting RA. This working group should meet in December/January annually and come up with a set of input assumptions (i.e. growth rate, drop off rate) used for forecasting DR estimates.

[36] Represent the monthly peak temperatures for the highest year out of a 10 year span. Exhibit SGE-03, Page 14.

[37] Christensen Associates Energy Consulting 2012 Load Impact Evaluation of Southern California Edison's Residential Summer Discount Plan (SDP) Program, April 1, 2013, Table 4-3d.

[38] Exhibit SCE-03, Table 1, 2012 RA for the month of September.

EXHIBIT PE-08

Form 1.5 - SCE Planning Area
California Energy Demand 2010-2020 Staff Revised Forecast
Extreme Temperature Peak Demand (MW)

Year	1-in-2 Temperatures	1-in-5 Temperatures	1-in-10 Temperatures	1-in-20 Temperatures	1-in-5 Multiplier	1-in-10 Multiplier	1-in-20 Multiplier
2009	22,747	24,294	24,749	25,113	1.068	1.088	1.104
2010	22,877	24,433	24,891	25,257	1.068	1.088	1.104
2011	23,181	24,758	25,221	25,592	1.068	1.088	1.104
2012	23,537	25,137	25,608	25,984	1.068	1.088	1.104
2013	23,912	25,538	26,016	26,399	1.068	1.088	1.104
2014	24,218	25,864	26,349	26,736	1.068	1.088	1.104
2015	24,543	26,212	26,703	27,095	1.068	1.088	1.104
2016	24,876	26,567	27,065	27,463	1.068	1.088	1.104
2017	25,226	26,941	27,446	27,850	1.068	1.088	1.104
2018	25,561	27,300	27,811	28,220	1.068	1.088	1.104
2019	25,901	27,663	28,181	28,595	1.068	1.088	1.104

EXHIBIT PE-09

Form 1.5d - Statewide
Final California Energy Demand Forecast, 2012 - 2022
1 in 10 Net Electricity Peak Demand by Agency and Balancing Authority (MW)

Balancing Authority	Agency	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Average Annual Growth 2011 - 2022
	CCSF	133	137	141	143	146	148	149	151	152	153	154	154	1.34%
	NCPA - Greater Bay Area	238	245	250	254	258	262	266	269	273	275	278	279	1.46%
	Other NP15 LSEs - Bay Area	3	3	3	3	3	3	3	3	3	3	3	4	2.65%
	PG&E Service Area - Greater Bay Area	8,181	8,379	8,581	8,707	8,825	8,945	9,059	9,170	9,292	9,410	9,520	9,622	1.49%
	Silicon Valley Power	453	464	476	484	491	496	503	508	511	514	516	516	1.19%
Greater Bay Area Subtotal		9,008	9,228	9,450	9,590	9,723	9,855	9,980	10,101	10,230	10,355	10,472	10,575	1.47%
	CDWR-N*	234	234	234	234	234	234	234	234	234	234	234	234	0.00%
	NCPA - Non Bay Area	238	244	249	253	257	260	263	267	270	273	275	278	1.42%
	Other NP15 LSEs - Non Bay Area	93	95	97	98	99	101	102	104	105	106	107	106	1.20%
	PG&E Service Area - Non Bay Area	9,729	9,963	10,202	10,353	10,495	10,636	10,771	10,903	11,048	11,189	11,320	11,442	1.49%
	WAPA	249	256	260	264	268	271	273	275	277	279	280	280	1.07%
Total North of Path 15		19,551	20,020	20,492	20,792	21,075	21,357	21,625	21,883	22,164	22,436	22,687	22,914	1.45%
	CDWR-ZP26*	279	279	279	279	279	279	279	279	279	279	279	279	0.00%
	PG&E Service Area - ZP26	2,419	2,477	2,537	2,575	2,610	2,646	2,680	2,713	2,749	2,783	2,816	2,847	1.49%
Total Zone Path 26		2,698	2,756	2,816	2,854	2,889	2,925	2,959	2,992	3,028	3,062	3,095	3,126	1.35%
Total Valley		13,241	13,548	13,858	14,057	14,242	14,426	14,603	14,774	14,962	15,143	15,310	15,464	1.42%
Total North of Path 26		22,249	22,776	23,308	23,647	23,965	24,281	24,583	24,875	25,192	25,498	25,782	26,039	1.44%
	Merced	90	92	94	96	97	98	99	100	100	101	101	100	0.96%
	Turlock Irrigation District	514	525	538	545	552	557	564	570	577	583	588	593	1.31%
Total Turlock Irrigation District Control Area		603	617	632	641	649	656	663	671	677	685	690	693	1.27%
	City of Shasta Lake	21	22	22	23	23	23	23	23	23	23	23	23	0.83%
	Modesto Irrigation District	682	698	715	726	734	742	751	758	767	776	782	788	1.32%
	Redding	249	256	260	265	268	272	277	280	285	289	293	296	1.58%
	Roseville	353	361	370	375	381	385	391	396	401	406	410	413	1.44%
	SMUD	3,305	3,384	3,465	3,512	3,558	3,609	3,656	3,699	3,746	3,789	3,831	3,869	1.44%
	WAPA (SMUD)	207	212	217	222	225	228	230	233	235	237	237	238	1.28%
Total SMUD/WAPA Control Area		4,817	4,933	5,049	5,122	5,189	5,260	5,327	5,389	5,457	5,520	5,576	5,628	1.42%
	Anaheim	605	620	635	645	653	662	670	680	689	694	700	705	1.40%
	MWD	21	21	21	21	21	21	21	21	21	21	21	21	0.00%
	Other SP15 LSEs - LA Basin	291	298	305	310	313	317	322	326	330	335	338	341	1.45%
	Pasadena	313	322	330	333	336	339	342	345	349	353	357	360	1.28%
	Riverside	594	611	625	634	640	650	659	670	680	687	695	701	1.52%
	SCE Service Area - LA Basin	17,485	17,940	18,371	18,632	18,867	19,123	19,381	19,635	19,899	20,149	20,384	20,598	1.50%
	Vernon	177	181	185	190	192	192	193	193	193	193	191	190	0.65%
LA Basin Subtotal		19,486	19,993	20,473	20,764	21,023	21,304	21,588	21,870	22,161	22,432	22,685	22,917	1.49%
	CDWR-S*	374	374	374	374	374	374	374	374	374	374	374	374	0.00%
	SCE Service Area - Big Creek Ventura	3,373	3,460	3,543	3,595	3,639	3,689	3,739	3,788	3,839	3,886	3,932	3,974	1.50%
Big Creek/Ventura Subtotal		3,747	3,834	3,917	3,969	4,013	4,063	4,113	4,162	4,213	4,260	4,306	4,348	1.36%
	MWD	210	210	210	209	209	209	210	211	212	211	211	211	0.04%
	Other SP15 LSEs - Out of LA Basin	10	12	12	12	13	13	13	13	13	13	13	12	1.67%
	SCE Service Area - Out of LA Basin	674	692	708	717	727	736	746	756	766	776	785	792	1.48%
Total SCE TAC Area		24,127	24,741	25,320	25,670	25,985	26,325	26,671	27,012	27,364	27,693	28,001	28,280	1.45%
SDG&E Service Area		4,851	4,988	5,125	5,224	5,322	5,428	5,544	5,652	5,759	5,862	5,962	6,056	2.04%
Total South of Path 26		28,978	29,729	30,444	30,895	31,306	31,753	32,214	32,664	33,124	33,555	33,962	34,335	1.55%
	Burbank	349	357	366	370	376	380	385	389	394	399	404	407	1.41%
	Glendale	380	390	399	406	410	416	422	427	433	438	445	452	1.59%
	LADWP	6,451	6,601	6,760	6,852	6,929	7,009	7,087	7,165	7,259	7,350	7,439	7,527	1.41%
Total LADWP Control Area		7,181	7,348	7,525	7,628	7,715	7,805	7,894	7,982	8,085	8,187	8,288	8,386	1.42%
Imperial Irrigation District Control Area		1,073	1,105	1,136	1,155	1,173	1,192	1,211	1,231	1,253	1,276	1,275	1,289	1.68%
Total CAISO Noncoincident Peak		51,227	52,505	53,752	54,541	55,271	56,034	56,798	57,539	58,316	59,053	59,744	60,375	1.50%
Total CAISO Coincident Peak		49,998	51,245	52,462	53,232	53,945	54,689	55,435	56,158	56,916	57,635	58,310	58,926	1.50%
Total Statewide Noncoincident Peak		64,901	66,509	68,094	69,086	69,997	70,947	71,893	72,811	73,788	74,721	75,573	76,370	1.49%
Total Statewide Coincident Peak		63,343	64,913	66,460	67,428	68,317	69,244	70,167	71,064	72,017	72,927	73,760	74,537	1.49%

* Entries for California Department of Water Resources are estimated actual peaks. Staff provides slightly higher short-run totals for California ISO/CPUC Resource Adequacy proceedings reflecting potential peak need.
Table only developed for the mid case. Table developed based on weather-adjusted 2011 peak estimates

EXHIBIT PE-10

Form 1.5e - Statewide
Final California Energy Demand Forecast, 2014 - 2024, Mid Demand Baseline, Low Mid AAEE Savings
1 in 20 Net Electricity Peak Demand by Agency and Balancing Authority (MW)

Balancing Authority	Agency	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Average Annual Growth 2013 - 2024
	CCSF	147	150	153	154	156	157	159	160	161	166	168	169	1.24%
	NCPA - Greater Bay Area	239	244	249	252	255	258	261	264	267	269	271	273	1.24%
	Other NP15 LSEs - Bay Area	7	7	7	7	7	7	7	7	7	8	8	8	1.22%
	PG&E Service Area - Greater Bay Area	8,413	8,569	8,644	8,655	8,667	8,719	8,762	8,810	8,845	8,878	8,887	8,893	0.51%
	Silicon Valley Power	502	509	518	524	528	535	539	543	546	550	554	556	0.93%
Greater Bay Area Subtotal		9,308	9,479	9,572	9,592	9,614	9,677	9,729	9,785	9,827	9,871	9,888	9,898	0.56%
	CDWR-N	264	264	264	264	264	264	264	264	264	264	264	264	0.00%
	NCPA - Non Bay Area	264	269	275	279	282	286	290	295	297	301	304	306	1.34%
	Other NP15 LSEs - Non Bay Area	37	38	39	40	40	41	41	42	43	43	44	44	1.63%
	PG&E Service Area - Non Bay Area	10,788	11,049	11,234	11,326	11,419	11,554	11,681	11,814	11,929	12,043	12,123	12,188	1.12%
	WAPA	173	176	179	181	183	185	187	188	189	190	192	193	1.02%
Total North of Path 15		20,833	21,275	21,563	21,682	21,802	22,007	22,192	22,387	22,549	22,711	22,814	22,893	0.86%
	CDWR-ZP26	315	315	315	315	315	315	315	315	315	315	315	315	0.00%
	PG&E Service Area - ZP26	2,313	2,355	2,374	2,374	2,377	2,391	2,403	2,417	2,427	2,435	2,437	2,436	0.47%
Total Zone Path 26		2,628	2,670	2,689	2,689	2,692	2,706	2,718	2,732	2,742	2,750	2,752	2,751	0.42%
Total Valley		14,154	14,465	14,679	14,778	14,880	15,037	15,181	15,335	15,463	15,589	15,678	15,746	0.97%
Total North of Path 26		23,462	23,944	24,251	24,371	24,494	24,713	24,910	25,119	25,290	25,460	25,566	25,644	0.81%
	Merced	103	104	106	107	107	108	109	111	112	112	113	113	0.84%
	Turlock Irrigation District	576	588	600	608	615	622	631	641	649	657	664	671	1.40%
Total Turlock Irrigation District Control Area		679	692	705	714	721	730	740	752	761	769	777	784	1.32%
	City of Shasta Lake	36	36	37	39	39	39	40	40	40	40	40	40	0.96%
	Modesto Irrigation District	765	781	795	804	812	822	832	844	852	861	868	876	1.23%
	Redding	306	313	319	323	327	333	338	345	350	355	359	364	1.60%
	Roseville	391	399	407	412	416	423	428	434	440	445	450	453	1.36%
	SMUD	3,516	3,580	3,649	3,680	3,726	3,771	3,821	3,867	3,917	3,965	4,012	4,059	1.31%
	WAPA (SMUD)	142	144	146	149	151	152	153	154	155	156	158	159	1.03%
Total SMUD/WAPA Control Area		5,156	5,252	5,354	5,408	5,472	5,540	5,612	5,684	5,754	5,822	5,887	5,950	1.31%
	Anaheim	645	657	671	680	688	696	707	715	724	731	738	746	1.33%
	MWD	24	24	24	24	24	24	24	24	24	24	24	24	0.00%
	Other SP15 LSEs - LA Basin	320	328	335	339	343	348	352	357	363	367	371	374	1.41%
	Pasadena	332	339	344	346	348	349	353	355	357	360	361	361	0.76%
	Riverside	684	697	712	722	732	743	753	765	775	785	793	801	1.45%
	SCE Service Area - LA Basin	18,349	18,719	18,936	19,038	19,138	19,288	19,439	19,619	19,779	19,911	20,003	20,075	0.82%
	Vernon	198	201	205	207	208	210	211	212	212	213	213	212	0.59%
LA Basin Subtotal		20,552	20,965	21,226	21,356	21,482	21,658	21,837	22,046	22,233	22,390	22,501	22,592	0.86%
	CDWR-S	422	422	422	422	422	422	422	422	422	422	422	422	0.00%
	SCE Service Area - Big Creek Ventura	3,650	3,715	3,744	3,751	3,757	3,774	3,791	3,812	3,831	3,846	3,856	3,866	0.52%
Big Creek/Ventura Subtotal		4,072	4,137	4,166	4,173	4,179	4,196	4,213	4,234	4,253	4,268	4,278	4,288	0.47%
	MWD	241	241	238	237	237	237	237	237	237	237	237	237	-0.14%
	Other SP15 LSEs - Out of LA Basin	12	12	12	14	13	13	13	13	13	13	13	14	1.41%
	SCE Service Area - Out of LA Basin	745	769	789	803	816	830	845	861	875	889	902	911	1.85%
Total SCE TAC Area		25,622	26,123	26,432	26,583	26,728	26,934	27,147	27,391	27,611	27,796	27,932	28,043	0.82%
Valley Electric Association		125	126	127	127	128	128	129	129	129	129	129	129	0.29%
SDG&E Service Area		5,349	5,437	5,497	5,517	5,564	5,614	5,656	5,682	5,700	5,710	5,705	5,700	0.58%
Total South of Path 26		31,096	31,686	32,056	32,227	32,419	32,676	32,932	33,203	33,440	33,636	33,766	33,872	0.78%
	Burbank	326	332	335	338	341	345	347	352	355	357	359	361	0.93%
	Glendale	366	373	378	381	385	389	392	397	402	405	409	411	1.06%
	LADWP	6,654	6,781	6,887	6,945	7,006	7,061	7,134	7,228	7,316	7,401	7,470	7,535	1.14%
Total LADWP Control Area		7,346	7,486	7,600	7,664	7,732	7,795	7,873	7,977	8,073	8,163	8,238	8,307	1.12%
Imperial Irrigation District Control Area		1,046	1,075	1,099	1,123	1,151	1,179	1,207	1,237	1,241	1,261	1,283	1,304	2.02%
Total CAISO Noncoincident Peak		54,557	55,630	56,307	56,598	56,913	57,389	57,842	58,322	58,730	59,096	59,332	59,516	0.79%
Total CAISO Coincident Peak		53,248	54,295	54,956	55,239	55,547	56,012	56,454	56,922	57,321	57,678	57,908	58,088	0.79%
Total Statewide Noncoincident Peak		68,784	70,135	71,065	71,507	71,989	72,634	73,275	73,972	74,559	75,111	75,516	75,862	0.89%
Total Statewide Coincident Peak		67,133	68,452	69,360	69,791	70,261	70,891	71,516	72,197	72,770	73,308	73,704	74,041	0.89%

NOTES:

Table developed based on weather-adjusted 2012 and 2013 peak estimates.

For PG&E service territory, Bay Area Growth is based on projections for forecasting climate zones 4 and 5, non-Bay Area on climate zones 1, 2, and 3, and ZP 26 on climate zone 1.

For SCE service territory, LA Basin growth is based on projections for forecasting climate zones 8, 9, and 10, Big Creek-Ventura on climate zone 8, and Out of LA Basin on climate zone 7.

In 2013, Valley Electric Association became a CAISO participating transmission owner. Most of the peak demand shown for this entry comes from outside of California.

Entries for California Department of Water Resources are not estimated actual peaks. Staff provides slightly higher totals for California ISO/CPUC Resource Adequacy proceedings to account for potential peak need.

Actual peak forecasts for CDWR are 152MW for CDWR-N, 288 MW for CDWR-ZP26, and 160 MW for CDWR-S.

EXHIBIT PE-11

2.3.3.6 *Transmission Projects*

The study included all existing transmission in service and the expected future projects that have been approved by the ISO but are not yet in service. Refer to tables 7.1.1 and 7.1.2 of chapter 7 (Transmission Project Updates) for the list of projects that were modeled in the base cases but that are not yet in service. Also included in the study cases were generation interconnection related transmission projects that were included in executed generator interconnection agreements (LGIA) for generation projects included in the base case.

2.3.3.7 *Load Forecast*

The assessment used the California Energy Demand Forecast 2014-2024 released by California Energy Commission (CEC) dated January 2014 (posted January 10, 2014) using the Mid Case LSE and Balancing Authority Forecast spreadsheet of February 8, 2014.

During 2013, the CEC, CPUC and ISO engaged in collaborative discussion on how to consistently account for reduced energy demand from energy efficiency in these planning and procurement processes. To that end, the 2013 Integrated Energy Policy Report (IEPR) final report, published on January 23, 2014, recommends using the Mid Additional Achievable Energy Efficiency (AAEE) scenario for system-wide and flexibility studies for the CPUC 2014 LTPP and ISO 2014-15 TPP cycles. Because of the local nature of reliability needs and the difficulty of forecasting load and AAEE at specific locations and estimating their daily load-shape impacts, using the Low-Mid AAEE scenario for local studies is more prudent at this time.

The 1-in-10 load forecasts were modeled in each of the local area studies. The 1-in-5 coincident peak load forecasts were used for the backbone system assessments as it covers a vast geographical area with significant temperature diversity. More details of the demand forecast are provided in the discussion sections of each of the study areas.

Light Load and Off-Peak Conditions

The assessment evaluated the light load and off-peak conditions in all study areas of the ISO balancing authority to satisfy NERC compliance requirement 1.3.6 for TPL-001, TPL-002 and TPL-003. The ISO light load conditions represented the system minimum load conditions while the off-peak load conditions ranged from 50 percent to 70 percent of the peak load in that area, such as weekends. Critical system conditions in specific study areas can occur during partial peak periods because of loading, generation dispatch and facility rating status and were studied accordingly.

2.3.3.8 *Reactive Power Resources*

Existing and new reactive power resources were modeled in the study base cases to ensure realistic voltage support capability. These resources include generators, capacitors, static var compensators (SVC) and other devices. Refer to area-specific study sections for a detailed list of generation plants and corresponding assumptions. Two of the key reactive power resources that were modeled in the studies include the following:

- all shunt capacitors in the SCE service territory; and

EXHIBIT PE-12

Form 1.5d
California Energy Demand 2010-2020 Staff Revised Forecast
1-in-10 Net Electricity Peak Demand by Agency and Balancing Authority

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Average Annual Growth 2010-2020
PG&E Service Area - Greater Bay Area	8,082	8,114	8,199	8,300	8,400	8,467	8,535	8,605	8,684	8,757	8,828	8,912	0.9%
Silicon Valley Power	509	512	520	529	536	541	546	551	557	562	567	572	1.1%
NCPA - Greater Bay Area	286	288	292	297	301	304	307	310	314	317	320	324	1.2%
Other NP15 LSEs - Greater Bay Area	6	6	6	6	6	6	6	6	6	6	6	6	0.4%
CCSF	114	114	115	116	117	117	117	117	118	118	118	118	0.3%
Greater Bay Area Local Area	8,997	9,034	9,131	9,247	9,360	9,435	9,511	9,590	9,679	9,760	9,839	9,932	1.0%
North of Path 26	23,112	23,278	23,594	23,959	24,323	24,598	24,878	25,166	25,484	25,784	26,084	26,423	1.3%
Turlock Irrigation District Control Area	684	692	705	719	734	746	759	772	786	800	813	829	1.8%
SMUD/WAPA Control Area	4,932	4,963	5,032	5,120	5,207	5,279	5,347	5,410	5,475	5,540	5,607	5,679	1.4%
SCE Service Area - LA Basin	17,770	17,874	18,114	18,394	18,689	18,928	19,182	19,442	19,716	19,978	20,243	20,529	
Anaheim	606	608	616	625	634	641	649	657	665	672	680	688	1.2%
Riverside	638	645	657	671	686	698	712	725	739	753	768	783	2.0%
Vernon	191	191	192	194	196	198	200	201	203	204	206	207	0.8%
MWD	23	22	22	22	22	22	22	22	22	22	22	22	-0.3%
Other SP15 LSEs - LA Basin	228	230	234	238	243	247	251	255	260	264	268	273	1.7%
Pasadena	326.078	327.084	329.131	330.995	331.546	331.283	331.813	332.473	333.024	333.554	333.942	334.428	0.2%
LA Basin Local Area	19,782	19,898	20,164	20,475	20,800	21,064	21,346	21,634	21,937	22,227	22,520	22,836	1.4%
SCE Service Area - Big Creek Ventura	4,229	4,254	4,311	4,377	4,447	4,504	4,564	4,626	4,690	4,753	4,816	4,883	1.4%
CDWR-S	200	300	300	300	300	300	300	300	300	300	300	300	0.0%
Big Creek/Ventura Local Area	4,425	4,556	4,613	4,680	4,749	4,806	4,866	4,928	4,993	5,055	5,118	5,186	1.3%
Total SCE TAC Area	25,293	25,545	25,878	26,266	26,675	27,008	27,362	27,725	28,106	28,472	28,842	29,240	1.4%
SDG&E Service Area	4,935	4,967	5,036	5,124	5,212	5,277	5,341	5,402	5,470	5,535	5,603	5,673	1.3%
Total South of Path 26	30,331	30,617	31,019	31,497	31,996	32,394	32,814	33,239	33,691	34,123	34,563	35,032	1.4%
LADWP Control Area	6,999	6,975	7,040	7,139	7,209	7,250	7,289	7,330	7,370	7,410	7,453	7,501	0.7%
Imperial Irrigation District Control Area	1,040	1,062	1,091	1,123	1,151	1,175	1,201	1,230	1,260	1,290	1,321	1,354	2.5%
Total CAISO Noncoincident Peak	53,443	53,895	54,612	55,456	56,319	56,992	57,692	58,405	59,175	59,907	60,647	61,455	1.3%
Total CAISO Coincident Peak	52,160	52,601	53,302	54,125	54,967	55,624	56,307	57,004	57,754	58,469	59,192	59,981	1.3%
Total Statewide Noncoincident Peak	67,098	67,588	68,480	69,557	70,619	71,442	72,288	73,148	74,066	74,947	75,842	76,818	1.3%
Total Statewide Coincident Peak	65,487	65,965	66,836	67,887	68,925	69,727	70,553	71,392	72,288	73,148	74,022	74,975	1.3%

*Balancing Authority Tables exclude LSEs located in non-California-based control areas.

EXHIBIT PE-13

Bill Powers

From: April Rose Sommer <asommer@biologicaldiversity.org>
Sent: Wednesday, April 08, 2015 2:43 PM
To: Bill Powers
Subject: FW: A.14-11-016 Moorpark RFO CBD Data Request #3

From: Tristan Reyes Close [mailto:Tristan.ReyesClose@sce.com]
Sent: Wednesday, April 8, 2015 2:37 PM
To: April Sommer
Cc: Tristan Reyes Close
Subject: RE: A.14-11-016 Moorpark RFO CBD Data Request #3

Hi April, I apologize, I thought our discussion confirmed things, but yes, you are right, we do not have the information you requested readily available. I think I misunderstood. I will send out a formal response to your question as soon as possible, but no later than COB tomorrow.

Thanks,
Tristan

Tristan Reyes Close
Senior Attorney
Southern California Edison
2244 Walnut Grove Ave.
Rosemead, CA 91770
(626) 302-2883
tristan.reyesclose@sce.com

From: April Sommer [mailto:ASommer@biologicaldiversity.org]
Sent: Wednesday, April 08, 2015 1:50 PM
To: Tristan Reyes Close
Subject: RE: A.14-11-016 Moorpark RFO CBD Data Request #3

Hi Tristan,
Just wanted to check in with you regarding CBD's data request #3. I understood from our phone call that SCE does not have the information requested - Final California Energy Demand Forecast, 2014 - 2024, Mid Demand Baseline, Low Mid AAEE Savings 1 in 10 Net Electricity Peak Demand by Agency and Balancing Authority (MW) for the Moorpark Sub-Area. Can you please confirm this?
Thank you,
April

From: Tristan Reyes Close [mailto:Tristan.ReyesClose@sce.com]
Sent: Thursday, April 2, 2015 1:38 PM
To: April Sommer
Subject: RE: A.14-11-016 Moorpark RFO CBD Data Request #3

EXHIBIT PE-14

Form 1.5d - Statewide
Final California Energy Demand Forecast, 2014 - 2024, Mid Demand Baseline, Mid AAEE Savings
1 in 10 Net Electricity Peak Demand by Agency and Balancing Authority (MW)

Balancing Authority	Agency	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Average Annual Growth 2013 - 2024
	CCSF	146	149	152	153	155	156	158	159	160	164	166	167	1.19%
	NCPA - Greater Bay Area	235	240	245	248	251	254	257	260	264	266	268	270	1.29%
	Other NP15 LSEs - Bay Area	7	7	7	7	7	7	7	7	7	8	8	8	1.22%
	PG&E Service Area - Greater Bay Area	8,222	8,368	8,420	8,392	8,374	8,382	8,393	8,407	8,406	8,400	8,371	8,336	0.13%
	Silicon Valley Power	494	501	512	516	520	526	531	535	538	542	544	546	0.93%
Greater Bay Area Subtotal		9,104	9,264	9,336	9,316	9,307	9,325	9,347	9,369	9,376	9,380	9,357	9,327	0.22%
	CDWR-N	264	264	264	264	264	264	264	264	264	264	264	264	0.00%
	NCPA - Non Bay Area	257	262	268	271	275	279	282	287	289	292	297	299	1.37%
	Other NP15 LSEs - Non Bay Area	37	38	39	40	40	41	41	42	43	43	44	44	1.63%
	PG&E Service Area - Non Bay Area	10,690	10,941	11,094	11,137	11,188	11,263	11,346	11,433	11,496	11,553	11,578	11,584	0.73%
	WAPA	171	174	177	179	182	183	185	186	187	189	190	191	1.03%
Total North of Path 15		20,521	20,943	21,177	21,206	21,256	21,355	21,464	21,581	21,655	21,721	21,729	21,708	0.51%
	CDWR-ZP26	315	315	315	315	315	315	315	315	315	315	315	315	0.00%
	PG&E Service Area - ZP26	2,305	2,345	2,359	2,348	2,342	2,346	2,349	2,354	2,353	2,351	2,341	2,330	0.10%
Total Zone Path 26		2,620	2,660	2,674	2,663	2,657	2,661	2,664	2,669	2,668	2,666	2,656	2,645	0.09%
Total Valley		14,038	14,338	14,515	14,554	14,606	14,690	14,782	14,880	14,947	15,007	15,028	15,025	0.62%
Total North of Path 26		23,141	23,603	23,851	23,870	23,913	24,015	24,128	24,249	24,323	24,387	24,385	24,353	0.46%
	Merced	102	103	105	106	106	107	108	109	110	110	111	111	0.76%
	Turlock Irrigation District	566	577	589	597	602	612	620	628	636	644	651	658	1.39%
Total Turlock Irrigation District Control Area		668	680	694	703	707	718	727	737	746	754	762	769	1.29%
	City of Shasta Lake	36	36	37	37	37	37	38	38	38	38	38	38	0.49%
	Modesto Irrigation District	743	756	771	780	787	797	807	817	826	835	842	849	1.22%
	Redding	300	307	313	318	321	326	332	337	342	348	351	357	1.60%
	Roseville	377	385	394	398	403	408	414	419	424	430	434	437	1.36%
	SMUD	3,371	3,432	3,499	3,529	3,572	3,615	3,664	3,708	3,755	3,801	3,847	3,892	1.32%
	WAPA (SMUD)	140	143	145	147	149	150	151	153	154	155	156	157	1.04%
Total SMUD/WAPA Control Area		4,966	5,059	5,158	5,208	5,269	5,334	5,407	5,472	5,539	5,607	5,668	5,730	1.31%
	Anaheim	621	633	645	654	662	671	681	688	697	705	711	718	1.32%
	MWD	24	24	24	24	24	24	24	24	24	24	24	24	0.00%
	Other SP15 LSEs - LA Basin	314	321	328	333	337	340	345	349	354	358	363	366	1.39%
	Pasadena	325	331	336	338	340	341	344	347	349	351	353	354	0.78%
	Riverside	671	684	697	708	717	727	737	749	759	768	777	786	1.45%
	SCE Service Area - LA Basin	18,224	18,580	18,743	18,763	18,799	18,854	18,937	19,056	19,144	19,200	19,215	19,203	0.48%
	Vernon	198	201	204	207	208	208	210	211	211	212	212	212	0.59%
LA Basin Subtotal		20,378	20,774	20,977	21,027	21,088	21,165	21,278	21,423	21,538	21,618	21,654	21,662	0.56%
	CDWR-S	422	422	422	422	422	422	422	422	422	422	422	422	0.00%
	SCE Service Area - Big Creek Ventura	3,613	3,675	3,694	3,685	3,679	3,678	3,683	3,691	3,697	3,698	3,693	3,686	0.18%
Big Creek/Ventura Subtotal		4,035	4,097	4,116	4,107	4,101	4,100	4,105	4,113	4,119	4,120	4,115	4,108	0.16%
	MWD	241	241	238	237	237	237	237	237	237	237	237	237	-0.14%
	Other SP15 LSEs - Out of LA Basin	11	12	12	14	13	13	13	13	13	13	13	14	2.22%
	SCE Service Area - Out of LA Basin	728	752	770	778	788	798	810	822	834	843	851	857	1.49%
Total SCE TAC Area		25,393	25,875	26,114	26,163	26,228	26,314	26,443	26,609	26,741	26,831	26,870	26,878	0.52%
Valley Electric Association		122	123	124	124	125	125	126	126	126	126	126	126	0.29%
SDG&E Service Area		5,216	5,298	5,342	5,337	5,364	5,386	5,408	5,417	5,414	5,403	5,376	5,348	0.23%
Total South of Path 26		30,731	31,297	31,580	31,624	31,717	31,825	31,978	32,152	32,282	32,360	32,373	32,352	0.47%
	Burbank	322	327	331	334	336	339	341	346	349	352	354	355	0.89%
	Glendale	356	363	368	372	375	379	382	387	391	394	398	400	1.07%
	LADWP	6,497	6,621	6,724	6,781	6,840	6,895	6,967	7,058	7,144	7,227	7,295	7,358	1.14%
Total LADWP Control Area		7,175	7,311	7,423	7,487	7,551	7,613	7,690	7,791	7,884	7,973	8,047	8,113	1.12%
Imperial Irrigation District Control Area		1,040	1,070	1,094	1,118	1,146	1,174	1,201	1,231	1,235	1,255	1,277	1,298	2.04%
Total CAISO Noncoincident Peak		53,872	54,899	55,430	55,494	55,630	55,840	56,106	56,401	56,604	56,747	56,758	56,705	0.47%
Total CAISO Coincident Peak		52,579	53,582	54,100	54,162	54,295	54,500	54,760	55,048	55,246	55,385	55,396	55,344	0.47%
Total Statewide Noncoincident Peak		67,721	69,019	69,799	70,009	70,304	70,679	71,131	71,633	72,009	72,336	72,512	72,615	0.64%
Total Statewide Coincident Peak		66,096	67,362	68,124	68,329	68,616	68,983	69,424	69,914	70,281	70,600	70,772	70,872	0.64%

NOTES:

Table developed based on weather-adjusted 2012 and 2013 peak estimates.

For PG&E service territory, Bay Area Growth is based on projections for forecasting climate zones 4 and 5, non-Bay Area on climate zones 1, 2, and 3, and ZP 26 on climate zone 1.

For SCE service territory, LA Basin growth is based on projections for forecasting climate zones 8, 9, and 10, Big Creek-Ventura on climate zone 8, and Out of LA Basin on climate zone 7.

In 2013, Valley Electric Association became a CAISO participating transmission owner. Most of the peak demand shown for this entry comes from outside of California.

Entries for California Department of Water Resources are not estimated actual peaks. Staff provides slightly higher totals for California ISO/CPUC Resource Adequacy proceedings to account for potential peak need.

Actual peak forecasts for CDWR are 152MW for CDWR-N, 288 MW for CDWR-ZP26, and 160 MW for CDWR-S.

EXHIBIT PE-15

Bill Powers

From: Bernadette Del chiaro <bernadette@calseia.org>
Sent: Tuesday, February 17, 2015 2:15 PM
To: Bill Powers
Subject: Re: do you know MW capacity of net-metered rooftop solar installs in 2014?

hi! you can expect that we had at least a 25-30% increase over 2013. final numbers still pending

Bernadette Del Chiaro, Executive Director

California Solar Energy Industries Association (CALSEIA)

1107 9th Street, Ste 820, Sacramento, CA 95814

916-228-4567: bernadette@calseia.org: www.calseia.org

On Feb 17, 2015, at 12:36 PM, Bill Powers <powers.engineering@att.net> wrote:

Hi Bernadette,

Happy 2015! Question – does CALSEIA know how much rooftop solar was installed in California in 2014? There was a lot of press about installing 1,000 MW of rooftop solar in 2013 (see attached). However, I am having trouble locating accurate information on how much rooftop solar was installed in 2014.

Thanks,

Bill
<23-jan-14_REW_California Blows the Lid off Solar Records Installing 1GW of Rooftop Solar in 2013.pdf>

EXHIBIT PE-16

California Blows the Lid off Solar Records Installing 1GW of Rooftop Solar in 2013

Chris Meehan
January 23, 2014 | 0 Comments

In one year, 2013, California installed 1 gigawatt of rooftop solar. In 2014 the U.S. is anticipated to install 5 gigawatts of solar. So last year California installed about 20 percent of what the whole nation is anticipated to install this year on rooftops alone.

□To put this in perspective, it took California over 30 years to build 1,000 MW [i.e., 1 gigawatt] of rooftop solar, hitting that landmark in early 2013,□wrote California Solar Energy Industries Association (CalSEIA) Executive Director Bernadette Del Chiaro in a year in review statement last week. □Today, California is closing out the year with more than 2,000 MW of rooftop solar systems installed statewide. The CPUC□s latest figures report 1,917 MW of rooftop solar but those numbers exclude basically all of PG&E□s 2013 installations, by far the largest market in the state, as well as a significant number of installations in other utility territories,□she said.

One of the interesting things about the explosive growth in residential and business rooftop solar power is that most of this has happened *after* incentives offered by many utilities in the state have dried up. And the increases in installations continue to grow yearly. For instance, □California added 500 MW of distributed solar in 2012,□Del Chiaro said. Calling 2012 a former banner year in the state. □If California continues to grow its rooftop solar market at its 2013 pace, the state may very well top 5,000 MW in 2014□ far exceeding the goals of the Million Solar Roofs Initiative which aimed to install 3,000 MW of rooftop solar [in California] by the end of 2016.□

In her statement Del Chiaro also observed that in all California now has more than 4 gigawatts of solar power installed in the state when utility-scale solar projects are included. "Nearly twice as much installed capacity as exists at California's last remaining nuclear power plant, Diablo Canyon,□she said. All of which shows the success of California's efforts to grow its solar industry across all segments from manufacturing to installing solar.

The previous successes don't guarantee future success for the industry and for the continued growth of solar power in the Golden State. In fact, utilities increased their efforts to push back against incentive programs in 2013 and could face more battles in 2014. □Rooftop solar continues to face battles on multiple fronts with regards to net metering, incentives for solar heating and cooling systems, the future of tax credits, and the reining in of permitting and interconnection costs and obstacles,□Del Chiaro observed. □Whether California continues this historic growth depends largely on policy decisions to be made in 2014.□

The battles against net metering are gaining the largest media attention and aren't occurring just in California but in many states where solar is popular including Colorado and Arizona.

The original article was posted on SolarReviews.

The information and views expressed in this blog post are solely those of the author and not necessarily those of

EXHIBIT PE-17

STATE OF CALIFORNIA Edmund G. Brown Jr., *Governor*

PUBLIC UTILITIES COMMISSION
SAN FRANCISCO, CA 94102-3298

March 16, 2015 **Advice Letter 3175-E**

Russell G. Worden
Director, Regulatory Operations
Southern California Edison Company
8631 Rush Street
Rosemead, CA 91770

Subject: Information-Only Advice Letter – SCE's Report on Progress Towards the Net Energy Metering Transition Trigger Level as of January 31, 2015

Dear Mr. Worden:

Advice Letter 3175-E is effective February 10, 2015.

Sincerely,

Edward Randolph

Edward Randolph
Director, Energy Division

SOUTHERN CALIFORNIA
EDISON
An EDISON INTERNATIONAL Company

Russell G. Worden
Director, State Regulatory Operations

February 10, 2015

ADVICE 3175-E
(U 338-E)

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA
ENERGY DIVISION

SUBJECT: **Information-Only Advice Letter**
Southern California Edison Company's Report on Progress Towards the Net Energy Metering Transition Trigger Level as of January 31, 2015

PURPOSE

Pursuant to California Public Utilities Commission (Commission) Decision (D.)14-03-041, Southern California Edison Company (SCE) respectfully submits this information-only Advice Letter (AL) to provide notice of SCE's progress towards the Net Energy Metering (NEM) transition trigger level as of January 31, 2015.

BACKGROUND AND DISCUSSION

On April 4, 2014, the Commission issued D.14-03-041 to establish a transition period pursuant to Assembly Bill 327 (Ch. 611, Stats 2013) for customers enrolled in applicable NEM tariffs. D.14-03-041 ordered the Investor-Owned Utilities (IOUs)[1] to report their progress towards the NEM transition trigger level on a monthly basis, as required by Public Utilities Code Section 2827(c)(4)(C), and post the report on each IOU's website.[2] The IOUs collaborated with the Commission's Energy Division staff to develop the content and format of the monthly reports. Subsequently, the Energy Division staff provided the IOUs instructions to submit the monthly reports via an information-only advice filing pursuant to General Order (GO) 96-B, General Rule 6.

In compliance with D.14-03-041 and the Energy Division's directive, below is SCE's progress report towards the NEM transition trigger level as of January 31, 2015. This report is also posted on SCE's website, www.sce.com/nem. Please note that due to a

[1] The IOUs are SCE, Pacific Gas and Electric Company and San Diego Gas & Electric Company.
[2] D.14-03-041 at pp. 31-32 and Ordering Paragraph 7 at p. 40.

P.O. Box 800 8631 Rush Street Rosemead, California 91770 (626) 302-4177 Fax (626) 302-4829

continued high volume of new applications submitted to SCE, the MW from "Applications Received in January, 2015" was estimated. Estimation was necessary due to a processing backlog resulting from an abnormally high volume of applications. An average system size (kW) per application was multiplied by the actual number of applications submitted through January 31, 2015. The average system size was calculated using the actuals from applications processed in October, November and December 2014.

Monthly AB 327 Net Energy Metering (NEM) Program Limit Report [1]
Data updated as of January, 2015

Total Available MW Cap	**2,240**	**MW**	**5% of 44,807 MW**
Applications Received in January, 2015[2] (New requests for NEM interconnection)	# 3,996	MWs 26.3	
Total NEM Applications in Queue January, 2015 (Total pending requests for NEM interconnection)	# 7,669	MWs 94.2	
Cumulative NEM Installations[3] (Projects approved for NEM interconnection)	# 108,465	MWs 919.7	
NEM Installations and Applications in Queue (Cumulative MW installed under NEM + NEM MW in Queue)	# 116,134	MWs 1,013.9	Percentage 2.26%
Remaining MW to Cap (NEM Cap minus (Cumulative MW installed under NEM + NEM MW in Queue))		MWs 1,226.1	

NOTES:

[1]The purpose of this report is to adhere to Public Utilities (PU) Code Section 2827(c)(4)(C), which directs each large electrical corporation to file a monthly report with the California Public Utilities Commission detailing the progress toward the NEM program limit. This report includes all systems either seeking interconnection or interconnected under the NEM program pursuant to PU Code Section 2827 (e.g., solar, wind, fuel cells using renewable fuels, etc.)

[2]The MW from Applications Received in January, 2015 was estimated. Estimation was necessary due to a processing backlog resulting from an abnormally high volume of applications. An average system size (kW) per application was multiplied by the actual number of applications submitted through January 31, 2015. The average system size was calculated using the actuals from applications processed in October, November and December 2014.

[3]Includes cumulative installations approved for NEM interconnection since NEM inception in 1996 (does not include systems that terminated NEM interconnection with the utility).

STATE OF CALIFORNIA Edmund G. Brown Jr., *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

February 17, 2015

Advice Letter 3159-E

Russell G. Worden
Director, State Regulatory Operations
Southern California Edison Company
8631 Rush Street
Rosemead, CA 91770

SUBJECT: Information-Only Advice Letter SCE's Report on Progress Towards the Net Energy Metering Transition Trigger Level as of 12-31-14.

Dear Mr. Worden:

Advice Letter 3159-E is effective as of January 9, 2015.

Sincerely,

Edward Randolph

Edward Randolph
Director, Energy Division

SOUTHERN CALIFORNIA EDISON
An EDISON INTERNATIONAL Company

Megan Scott-Kakures
Vice President, State Regulatory Operations

January 9, 2015

ADVICE 3159-E
(U 338-E)

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA
ENERGY DIVISION

SUBJECT: **Information-Only Advice Letter**
Southern California Edison Company's Report on Progress Towards the Net Energy Metering Transition Trigger Level as of December 31, 2014

PURPOSE

Pursuant to California Public Utilities Commission (Commission) Decision (D.)14-03-041, Southern California Edison Company (SCE) respectfully submits this information-only Advice Letter (AL) to provide notice of SCE's progress towards the Net Energy Metering (NEM) transition trigger level as of December 31, 2014.

BACKGROUND AND DISCUSSION

On April 4, 2014, the Commission issued D.14-03-041 to establish a transition period pursuant to Assembly Bill 327 (Ch. 611, Stats 2013) for customers enrolled in applicable NEM tariffs. D.14-03-041 ordered the investor-owned utilities (IOUs)[1] to report their progress towards the NEM transition trigger level on a monthly basis, as required by Public Utilities Code Section 2827(c)(4)(C), and post the report on each IOU's website.[2] The IOUs collaborated with the Commission's Energy Division staff to develop the content and format of the monthly reports. Subsequently, the Energy Division staff provided the IOUs instructions to submit the monthly reports via an information-only advice filing pursuant to General Order (GO) 96-B, General Rule 6.

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1 The IOUs are SCE, Pacific Gas and Electric Company and San Diego Gas & Electric Company.

2 D.14-03-041 at pp. 31-32 and Ordering Paragraph 7 at p. 40.

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In compliance with D.14-03-041 and the Energy Division's directive, below is SCE's progress report towards the NEM transition trigger level as of December 31, 2014. This report is also posted on SCE's website, www.sce.com/nem. Please note that due to a continued high volume of new applications submitted to SCE, the MW from Applications Received in December, 2014 was estimated. Estimation was necessary due to a processing backlog resulting from an abnormally high volume of applications. An average system size (kW) per application was multiplied by the actual number of applications submitted through December 31, 2014. The average system size was calculated using the actuals from applications processed in September, October and November 2014.

Monthly AB 327 Net Energy Metering (NEM) Program Limit Report [1]
Data updated as of December, 2014

Total Available MW Cap	**2,240**	**MW**	**5% of 44,807 MW**
Applications Received in December, 2014 (New requests for NEM interconnection)	# 4,520	MWs[2] 32.5	
Total NEM Applications in Queue December, 2014 (Total pending requests for NEM interconnection)	# 7,811	MWs 94.1	
Cumulative NEM Installations[3] (Projects approved for NEM interconnection)	# 103,903	MWs 884.7	
NEM Installations and Applications in Queue (Cumulative MW installed under NEM + NEM MW in Queue)	# 111,714	MWs 978.8	Percentage 2.18%
Remaining MW to Cap (NEM Cap minus (Cumulative MW installed under NEM + NEM MW in Queue))		MWs 1,261.2	

NOTES:

[1]The purpose of this report is to adhere to Public Utilities (PU) Code Section 2827(c)(4)(C), which directs each large electrical corporation to file a monthly report with the California Public Utilities Commission detailing the progress toward the NEM program limit. This report includes all systems either seeking interconnection or interconnected under the NEM program pursuant to PU Code Section 2827 (e.g., solar, wind, fuel cells using renewable fuels, etc.)

[2]The MW from Applications Received in December, 2014 was estimated. Estimation was necessary due to a processing backlog resulting from an abnormally high volume of applications. An average system size (kW) per application was multiplied by the actual number of applications submitted through December 31, 2014. The average system size was calculated using the actuals from applications processed in September, October and November 2014.

[3]Includes cumulative installations approved for NEM interconnection since NEM inception in 1996 (does not include systems that terminated NEM interconnection with the utility).

PUBLIC UTILITIES COMMISSION
SAN FRANCISCO, CA 94102-3298

January 21, 2015

Advice Letter 3144-E

Megan Scott-Kakures
Vice President, Regulatory Operations
Southern California Edison Company
P O Box 800
Rosemead, CA 91770

Subject: Information-Only Advice Letter – SCE's Report on Progress towards the Net Energy Metering Transition Trigger Level as of November 30, 2014

Dear Ms. Scott-Kakures:

Advice Letter 3144-E was received by the Energy Division on December 10, 2014.

Sincerely,

Edward Randolph

Edward Randolph
Director, Energy Division

SOUTHERN CALIFORNIA
EDISON
An EDISON INTERNATIONAL Company

Megan Scott-Kakures
Vice President, State Regulatory Operations

December 10, 2014

ADVICE 3144-E
(U 338-E)

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA
ENERGY DIVISION

SUBJECT: **Information-Only Advice Letter**
Southern California Edison Company's Report on Progress Towards the Net Energy Metering Transition Trigger Level as of November 30, 2014

PURPOSE

Pursuant to California Public Utilities Commission (Commission) Decision (D.)14-03-041, Southern California Edison Company (SCE) respectfully submits this information-only Advice Letter (AL) to provide notice of SCE's progress towards the Net Energy Metering (NEM) transition trigger level as of November 30, 2014.

BACKGROUND AND DISCUSSION

On April 4, 2014, the Commission issued D.14-03-041 to establish a transition period pursuant to Assembly Bill 327 (Ch. 611, Stats 2013) for customers enrolled in applicable NEM tariffs. D.14-03-041 ordered the investor-owned utilities (IOUs)[1] to report their progress towards the NEM transition trigger level on a monthly basis, as required by Public Utilities Code Section 2827(c)(4)(C), and post the report on each IOU's website.[2] The IOUs collaborated with the Commission's Energy Division staff to develop the content and format of the monthly reports. Subsequently, the Energy Division staff provided the IOUs instructions to submit the monthly reports via an information-only advice filing pursuant to General Order (GO) 96-B, General Rule 6.

D.14-03-041, Ordering Paragraph (OP) 7 directs the IOUs to report their progress towards the NEM cap on a monthly basis and to post the information on their respective

1 The IOUs are SCE, Pacific Gas and Electric Company and San Diego Gas & Electric Company.
2 D.14-03-041 at pp. 31-32 and Ordering Paragraph 7 at p. 40.

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websites. Additionally, the ordering paragraph directs the IOUs to "develop an annual summary report."

The IOUs have been filing the above-referenced monthly reports on the 10th of each month. In addition, every October 1, the IOUs file an annual update to the denominator of the NEM cap pursuant to a 2012 Assigned Commissioner's Ruling, which updates the cap target and progress towards meeting that target.

The monthly reports, which include cumulative data, coupled with the annual October 1 filings fulfill the annual summary report requirement in D.14-03-041. Therefore, SCE does not intend to file a separate annual report.

In compliance with D.14-03-041 and the Energy Division's directive, below is SCE's progress report towards the NEM transition trigger level as of November 30, 2014. This report is also posted on SCE's website, www.sce.com/nem. Please note that due to a continued high volume of new applications submitted to SCE, the megawatt (MW) total shown under "Applications Received in November, 2014" is estimated. The estimation methodology used is based on an average system size (in kilowatts) per application multiplied by the actual number of applications submitted through November 30, 2014. The average system size was calculated using the actuals from applications processed in August and September 2014. Estimation was necessary due to a processing backlog that is the result of an abnormally high volume of applications.

Monthly AB 327 Net Energy Metering (NEM) Program Limit Report [1]
Data updated as of November 30, 2014

Total Available MW Cap	**2,240**	**MW**	**5% of 44,807 MW**
Applications Received in November, 2014[2] (New requests for NEM interconnection)	# 4,188	MWs 34.3	
Total NEM Applications in Queue November, 2014 (Total pending requests for NEM interconnection)	# 7,774	MWs 96.1	
Cumulative NEM Installations[3] (Projects approved for NEM interconnection)	# 99,915	MWs 855.2	
NEM Installations and Applications in Queue (Cumulative MW installed under NEM + NEM MW in Queue)	# 107,689	MWs 951.3	Percentage 2.12%
Remaining MW to Cap (NEM Cap minus (Cumulative MW installed under NEM + NEM MW in Queue))		MWs 1,288.7	

NOTES:

[1]The purpose of this report is to adhere to Public Utilities (PU) Code Section 2827(c)(4)(C), which directs each large electrical corporation to file a monthly report with the California Public Utilities Commission detailing the progress toward the NEM program limit. This report includes all systems either seeking interconnection or interconnected under the NEM program pursuant to PU Code Section 2827 (e.g., solar, wind, fuel cells using renewable fuels, etc.)

[2]The MW from Applications Received in November, 2014 was estimated. Estimation was necessary due to a processing backlog resulting from an abnormally high volume of applications. An average system size (kW) per application was multiplied by the actual number of applications submitted through November 30, 2014. The average system size was calculated using the actuals from applications processed in August and September 2014

[3]Includes cumulative installations approved for NEM interconnection since NEM inception in 1996 (does not include systems that terminated NEM interconnection with the utility).

EXHIBIT PE-18

MP6/ms6 5/14/2014

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 13-12-010 (Filed December 19, 2013)

ASSIGNED COMMISSIONER'S RULING TECHNICAL UPDATES TO PLANNING ASSUMPTIONS AND SCENARIOS FOR USE IN THE 2014 LONG TERM PROCUREMENT PLAN AND 2014-15 CAISO TPP

Energy Division, in consultation with the California Energy Commission (CEC), has determined technical updates are required to the February 27, 2014 Assigned Commissioner's Ruling (ACR) on "Planning Assumptions and Scenarios for use in the 2014 Long Term Procurement Plan (LTPP) and 2014-15 CAISO TPP." The ACR Attachment on Planning Assumptions and Scenarios and the associated Scenario Tool Excel workbook referenced in the herein Attachment are being updated.

There are five technical corrections that Energy Division has implemented, as detailed herein:

1. Corrections to account for avoided transmission and distribution losses from demand-side resources;
2. Updates to the managed demand forecast including revised Additional Achievable Energy Efficiency (AAEE) assumptions;
3. Corrections to the supply stack counting of once-through cooling (OTC) units in its year of assumed retirement;
4. Corrections to the language referring to the storage target identified in Decision (D.) 13-10-040; and

5. Documentation of corrections and updates that were previously announced by staff email to Rulemaking (R.) 13-12-010 parties on March 19, 2014.

1. Corrections to Account For Avoided Transmission and Distribution Losses from Demand-Side Resources

The Scenario Tool produces a loads and resources table that illustrates the projected balance of supply and demand in terms of available system capacity at coincident peak demand. Demand-side resource projections need to account for avoided transmission and distribution losses when calculating the balance of projected supply and demand. Earlier versions of the Scenario Tool included several customer-located resources to calculate the balance of projected supply and demand: AAEE, incremental small solar photovoltaic, incremental demand-side combined heat power, and demand response, but did not account for avoided transmission and distribution losses. The latest version of the Scenario Tool (version 2) corrects this error and the ACR Attachment (sections 4.1.6, 4.1.9, and 4.2.5) has been updated to describe accounting for avoided transmission and distribution losses. The table below specifies factors supplied by the CEC for accounting of avoided transmission and distribution losses. The factors are multiplied by demand-side resource projections to determine the avoided generation replaced by the presence of the demand-side resource. Contact Chris Kavalec (chris.kavalec@energy.ca.gov) at the CEC's Demand Analysis Office for further information on these factors.

Factors to Account for Avoided Transmission and Distribution Losses:

	PG&E	SCE	SDG&E
Peak, distribution losses only	1.067	1.051	1.071
Peak, transmission and distribution losses	1.097	1.076	1.096
Energy, transmission and distribution losses	1.096	1.068	1.0709

Note that these avoided transmission and distribution loss accounting adjustments do not affect renewable net short (RNS) calculations. RNS calculations are performed by reducing retail sales by the energy impact of demand-side resources to determine how much renewable energy must be delivered to customers to meet the Renewable Portfolio Standard (RPS), and do not involve avoided transmission and distribution losses. Therefore, no changes need to be made to the RPS portfolios.

2. Updates to the Managed Demand Forecast Including Revised AAEE Assumptions

There are two technical updates to the CEC's Integrated Energy Policy Report (IEPR) demand forecast tables that warrant adjustments to the Scenario Tool. The latest version of the Scenario Tool (version 2) incorporates these updates.

The first technical update incorporates revised AAEE projections based on the final results of CPUC's 2013 California Energy Efficiency Potential and Goals Study issued by ACR on March 3, 2014 in R.13-11-005. The revised AAEE projections have been incorporated into the April 15, 2014 version of the CEC's IEPR demand forecast plus AAEE tables posted here http://www.energy.ca.gov/2013_energypolicy/documents/demand-forecast_CMF/LSE_and_Balancing_Authority_Forecasts/). The relevant footnotes in the R.13-12-010 ACR Attachment (sections 4.1.1 through 4.1.4) have been updated. On a system-wide basis the AAEE changes are tiny, approximately -0.3% for peak impacts and -1.5% for energy impacts in 2024. By utility and at the transmission-level busbar scale, the changes have a non-trivial impact, therefore the revised AAEE projections are incorporated into both the Scenario Tool (version 2) and the busbar AAEE projections used in the California Independent System Operator's TPP and other local area studies.

Note that the RPS portfolios used in LTPP and TPP studies were created from RNS calculations using a previous version of the AAEE projections. Incorporating the revised AAEE projections would increase the RNS by about 100-200 GWh. This is considered a negligible impact and within forecasting uncertainty. Therefore, the RPS portfolios used in LTPP and TPP studies will not be updated.

The second technical update incorporates a minor non-dispatchable demand response accounting correction that was included in the latest version of the CEC's IEPR demand forecast tables posted here (http://www.energy.ca.gov/2013_energypolicy/documents/demand-forecast_CMF/LSE_and_Balancing_Authority_Forecasts/). The Scenario Tool originally accounted for this correction with a separate line item because earlier versions of the IEPR demand forecast tables did not include this correction. The latest version of the Scenario Tool (version 2) removes the line item because it is now accounted for in the latest IEPR demand forecast tables.

3. Corrections to the supply stack counting of OTC units in its year of assumed retirement

The original Scenario Tool did not count the capacity of an OTC unit in the year of assumed retirement. The compliance date for OTC units generally falls on December 31 of the compliance year. Therefore, if retirement is the assumed compliance method, the capacity of the OTC unit should still be counted in the compliance year, and not be considered retired until the next year. The latest version of the Scenario Tool (version 2) corrects this.

4. Corrections to the language referring to the energy storage target identified in D.13-10-040

The ACR Attachment and Scenario Tool both referred to the energy storage target identified in D.13-10-040 as either a "mandate" or a "target" and used the terms interchangeably. However, D.13-10-040 describes the storage target as only a target, and not a mandate. Therefore Energy Division staff corrected the storage language in the ACR Attachment (section 4.2.4) and Scenario Tool (version 2) to use the term "target" and not "mandate."

5. Documentation of corrections and updates that were previously announced by staff email to R.13-12-010 parties on March 19, 2014

There are three other minor corrections and updates to the original February 27, 2014 ACR Attachment that were previously announced by staff email to LTPP parties on March 19, 2014:

1. Corrections to the "DR Capacity in Local Area Reliability Studies" Table in section 4.2.5. The original table tallied Demand Response (DR) ex ante impacts using 1-in-2 weather year data, however, the intent was to tally 1-in-10 weather year data. The corrected table clarifies this and now lists the DR Program MW in 2024 using 1-in-10 weather year ex ante impacts.
2. Updates to the "RPS Portfolio Summary" Table in section 4.2.6. The original table summarized the seven RPS portfolios with limited information on how the portfolios were built and the intended use. The updated table provides greater detail on the information used to calculate the renewable net short for each portfolio and the intended use of the portfolio.

3. Corrections to the "RPS Portfolio Summary by CREZ" Table in the Appendix. The original table contained formatting that inadvertently hid several cells in the table. The corrected table now shows all cells.

IT IS RULED that:

The February 27, 2014 Assigned Commissioner's Ruling on "Planning Assumptions and Scenarios for use in the 2014 LTPP and 2014-15 CAISO TPP" and the associated Scenario Tool Excel workbook referenced in the Attachment are updated, as shown in the Attachment to this Ruling.

Dated May 14, 2014, at San Francisco, California.

/s/ MICHAEL PICKER
Michael Picker
Assigned Commissioner

Attachment

Amendment to February 27, 2014 Assigned Commissioner Ruling Attachment: Planning Assumptions and Scenarios for use in the CPUC Rulemaking R.13-12-010 (The 2014 Long-Term Procurement Plan Proceeding), and the CAISO 2014-15 Transmission Planning Process

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Table Index

values implied by the CED "Mid" load case embedded self-generation PV projection for each of the three major IOUs. The table below summarizes by IOU the implied peak impact factor and capacity factor.

Table 1: Small Solar PV Operational Attributes

Variable	PG&E	SCE	SDG&E	Average of all 3 IOUs
Peak impact factor	0.47	0.47	0.47	0.47
Capacity factor	0.18	0.19	0.20	0.19

4.1.6 Combined Heat and Power

The CED forecasts embed the impacts of initiatives such as the Self-Generation Incentive Program. As such, the default projection for behind-the-meter combined heat and power (CHP) assumes no change from what the CED forecasts embed. Besides the default projection, planning scenarios may model a low or high projection of behind-the-meter CHP ***incremental*** to the default projection. ICF International conducted a policy analysis of CHP resources through 2030 and produced a report published in July 2012.[25] The low incremental projection is based on a CEC analysis of the "Base" projection of on-site generation from the ICF report. The high incremental projection is based on a CEC analysis of the "High" projection of on-site generation from the ICF report.[26] Note that since the projections in the ICF report are statewide, these numbers are disaggregated to planning areas for the three major IOUs using ratios derived from the CEC analysis of the "Base" and "High" projections of on-site generation from the ICF report. This results in CAISO area 2024 incremental installed capacity projections of 955 MW in the low case, and 2,405 MW in the high case.

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[25] *See* Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment – Consultant Report at http://www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002-REV.pdf

[26] Straight-line interpolation for intervening years between the "Base" case and "High" case target years identified in the ICF report

Although behind-the-meter CHP is generally regarded as a demand-side resource, both the CED embedded CHP and any incremental amounts will be modeled as supply resources, and modelers will adjust upward the load forecast as needed when accounting for CED embedded self-generation on the supply-side. This maintains consistency with modeling practice that treats these resources as non-dispatchable generators with both capacity value and an annual production profile. Transmission and distribution loss-avoidance effects shall be accounted for. Absent more specific locational and technology type information for a resource projection, the default shall be to allocate aggregate resource projections to substations on the basis of peak load ratios, and to model capacity value at peak (peak impact factor) as 0.70 of installed capacity and annual energy production using a 0.80 capacity factor.

4.1.7 Demand Response

The CED forecasts embed the impacts of non-dispatchable demand response (DR) programs, in other words, those impacts are treated on the demand-side. These programs are generally non-event-based and/or tariff-based and include TOU rates, Permanent Load Shifting, and Real Time Pricing. Dispatchable DR programs, which are generally event-based price-responsive and reliability programs, are treated as supply resources.

There may be other effects that supply additional DR impacts, for example, a higher EV penetration could lead to charging models that can provide load shifting and frequency regulation by managing the charging times of an aggregate group of EVs. These speculative impacts are not accounted for at this time. Another expected future DR impact may come from defaulting residential customers to TOU rates. These impacts may be explored in the next major CEC IEPR planning cycle.

4.1.8 Energy Storage

Energy storage units shall be modeled as supply-side resources, therefore this document describes the planning assumptions for distribution-connected and customer-side storage, as well as transmission-connected storage, within the Supply-side Assumptions section.

4.1.9 Avoided Transmission and Distribution Losses

Demand-side resource projections need to account for avoided transmission and distribution losses when calculating the balance of projected supply and demand. The table below specifies factors supplied by the CEC for accounting of avoided transmission and distribution losses. The factors are multiplied by demand-side resource projections to determine the avoided generation replaced by the presence of the demand-side resource.

Table 2: Factors to Account for Avoided Transmission and Distribution Losses

	PG&E	SCE	SDG&E
Peak, distribution losses only	1.067	1.051	1.071
Peak, transmission and distribution losses	1.097	1.076	1.096
Energy, transmission and distribution losses	1.096	1.068	1.0709

4.2 Supply-side Assumptions

All supply-side resource assumptions are solely for planning purposes. Inclusion or exclusion of a specific project or resource in the planning cycle has no implications for existing or future contracts. To the extent a specific projected resource is not available, the analysis assumes an electrically equivalent resource will be available.

All supply-side resources should be categorized either as within a specific local area, as a generic system resource, or as out-of-state. Resources should be accounted for in terms of their most current net qualifying capacity (NQC). For purposes of constructing simple annual load and resource tables, August NQC values will be used. In the absence of a NQC, a resource's expected NQC should be based on its expected installed capacity adjusted for the peak impact value of that technology type. To the extent that NQC accounting methodologies change in the future, those changes should be reflected in LTPPs subsequent to the current LTPP. For variable resources, methods that can forecast production based on a variety of conditions are preferred to utilizing single point or year assumptions. In addition, generation profiles of variable resources are used in the production simulation model analysis. These profiles may also be used in TPP studies to determine output levels of these resources corresponding to the load levels (peak, off-peak, partial peak, and light load base cases) of the applicable studies. The Effective Load Carrying Capability (ELCC) method of assigning capacity value to wind and solar resources is expected to become available for the next cycle of developing planning assumptions. At this time, no degradation of resource production over time is accounted for in these planning assumptions.

4.2.1 Existing Resources

The capacities of existing resources shall be the monthly NQC values found in the 2014 Resource Adequacy compliance year NQC list.[27] The CAISO and CPUC both publish these lists annually on their respective websites.

4.2.2 Conventional Additions

The default values for conventional resource additions 50 MW or larger derive from the list of power plant siting cases maintained on the CEC website.[28] The default values for conventional resource additions smaller than 50 MW derive from other databases maintained by the CEC. The CEC updates these lists several times per year. A power plant project shall be counted if it (1) has a contract, (2) has been permitted, and (3) has begun construction. A power plant project that does not meet these criteria may be counted if the staff of the agency with permitting jurisdiction expects the project to come online within the planning horizon.[29]

4.2.3 Combined Heat and Power

Resources identified here export electricity to the grid. The Demand-side Assumptions section discusses resources that provide on-site energy. The default projection for exporting CHP assumes no net growth. Planning scenarios that model a higher penetration of exporting CHP shall add either a low or a high incremental projection of growth. ICF International conducted a policy

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[27] *See* Resource Adequacy Compliance Materials at http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/ra_compliance_materials.htm

[28] http://www.energy.ca.gov/sitingcases/all_projects.html

[29] The Oakley power plant project was approved by the CPUC but recently annulled by the California Court of Appeal: http://www.courts.ca.gov/opinions/documents/A138701.PDF Therefore, Oakley will not be assumed as a conventional resource addition. During the second year of the LTPP cycle, CPUC staff expects to facilitate additional studies with varying additional resource options to determine the best way to fill any need found from studies conducted during the first year of the LTPP cycle. At that time, there may be an opportunity to explore the efficacy of the Oakley power plant in meeting identified needs.

analysis of CHP resources through 2030 and produced a report in July 2012.[30] The low incremental projection is based on a CEC analysis of the "Base" projection of exporting CHP from the ICF report. The high incremental projection is based on a CEC analysis of the "High" projection of exporting CHP from the ICF report.[31] Note that since the projections in the ICF report are statewide projections, these numbers are adjusted downward by a factor of 0.8, approximately the CAISO area to statewide load ratio. This results in CAISO area 2024 installed capacity projections of 164 MW in the low case, and 1,855 MW in the high case.

Absent more specific locational and technology type information for a resource projection, the default shall be to allocate aggregate resource projections to substations on the basis of peak load ratios, and to model capacity value at peak (peak impact factor) as 0.70 of installed capacity. These resources are assumed to be dispatchable by the CAISO.

4.2.4 Energy Storage

CPUC Decision (D.)13-10-040 established a 2020 procurement target[32] of 1,325 MW installed capacity of new energy storage units within the CAISO planning area. Of that amount, 700 MW shall be transmission-connected, 425 MW shall be distribution-connected, and 200 MW shall be customer-side. D.13-10-040 also allocates procurement responsibilities for these amounts to each of the three major IOUs. Storage operational after January 1, 2010 and no later than December 31, 2024 shall count towards the procurement target. The default planning assumption for new storage capacity shall account for a conservative expected contribution to grid services and reliability from the storage procurement target in D.13-10-040. No further growth in new storage capacity is assumed post 2024.

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[30] *See* Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment – Consultant Report at http://www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002-REV.pdf

[31] Straight-line interpolation for intervening years between the "Base" case and "High" case target years identified in the ICF report

[32] The Decision specifies that resources must be online by 2024 so in the planning assumptions, target amounts are reached in 2024.

The 50 MW that CPUC Decision (D.)13-02-015 ordered SCE to procure is subsumed within the 2020 procurement target and shall not be (double) counted elsewhere in the planning assumptions.

While all storage can provide energy services, that is, storage can charge during periods of low energy prices and discharge during periods of high energy prices, their ability to provide capacity and flexibility (load-following, ancillary services, etc.) depends on their visibility and controllability by the CAISO. Transmission-connected storage will likely interconnect to the system near transmission substations and be visible and controllable by the CAISO. Therefore, all of the 700 MW of new transmission-connected storage described above is assumed to provide capacity and flexibility as a default.

The ability of distribution-connected storage to provide capacity and flexibility carries significant uncertainty, in part because this technology is new to the market, and in part because current policy and the CAISO market does not fully support the participation of distribution-connected resources. Therefore, only 50% of the 425 MW of new distribution-connected storage described above is assumed to provide capacity and flexibility as a default. This acknowledges that greater than zero percent but less than 100% of these resources are expected to provide such services.

The ability of customer-side storage to provide capacity and flexibility carries even higher uncertainty. Not only is the market new, but customer-side storage will likely be non-dispatchable by either the CAISO or the IOUs (absent significant policy and market changes) and it is unclear how much of customer-side storage will charge from the grid or on-site generation, and according to what schedule. Therefore, none of the 200 MW of new customer-side storage described above is assumed to provide capacity and flexibility as a default.

Note that although there are limits on the amount of storage procurement assumed to provide capacity and flexibility as described above, all 1,325 MWs can provide energy services and will be modeled as such in studies involving production cost simulations. The capacity limitation described above applies to power-flow type studies conducted in the CAISO's TPP. The table below describes the assumptions that shall be used for the technical characteristics and accounting of the three classes of storage described by D.13-10-040.

Table 3: Storage Operational Attributes

Values are MW in 2024	Transmission-connected	Distribution-connected	Customer-side
Total Installed Capacity	700	425	200
Amount providing capacity and flexibility	700	212.5	0
Amount with 2 hours of storage	280	170	100
Amount with 4 hours of storage	280	170	100
Amount with 6 hours of storage	140	85	0
Charging rate: If a unit is discharged and charged at the same power level, assume it takes 1.2 times as long to charge as it does to discharge. Example: 50 MW unit with 2 hours of storage. If the unit is charged at 50 MW, it will take 2.4 hours to charge. If the unit is charged at 25 MW, it will take 4.8 hours to charge.			

In the CAISO's TPP Base local area reliability studies, locations for this new storage capacity must be assumed. It is reasonable to assume that cost-effectiveness requirements for new storage capacity will lead to siting at the most effective locations to contribute to local area reliability. As the CAISO's technical studies in the 2014-15 TPP identify transmission constraints in the local areas, the CAISO will identify the effective busses for mitigating those constraints. The storage amounts providing capacity and flexibility identified in the table above will be distributed amongst effective busses within the local areas and modeled. These bus locations are potential development sites for storage and shall inform the actual procurement to meet the storage procurement target.

The default planning assumptions accounting for the storage procurement target are admittedly conservative. For example, the assumption that half of distribution-connected storage and all of customer-side storage does not provide capacity or flexibility probably undercounts their value. The intention is to model the grid conservatively to start with in order to reveal potential reliability needs. Any revealed reliability needs will be used to inform how the storage procurement target actually gets implemented. To enable this, during the second year of the LTPP cycle, CPUC staff expects to facilitate additional studies with varying additional resource options to determine the best way to fill any need found from studies conducted during the first year of the LTPP cycle. CPUC staff expects to explore two additional resource options for storage:

1. In addition to the default planning assumptions for new storage, add one or two new large-pumped hydro storage units, the exact MW amount depends on what the revealed need is. Note that according to D.13-10-040, the maximum size of pumped storage projects that count towards storage procurement target is 50 MW. Therefore if studies demonstrate that this additional resource option is the best way to fill any need, the LTPP proceeding will consider pumped storage projects larger than 50 MW in general solicitations for new capacity conducted by utilities.
2. In addition to the default planning assumptions for new storage, assume policy and market changes that enable a more complete contribution to grid services and reliability from new distribution-connected and customer-side storage. Additional storage beyond the storage procurement target may be assumed depending on what the revealed need is.

All energy storage described here is exclusive and incremental to any similar technologies that are accounted for as non-dispatchable DR (e.g. Permanent Load Shifting) embedded within the CEC's CED forecasts.

4.2.5 Demand Response

Dispatchable demand response (generally event-based price-responsive and reliability programs) shall be accounted for as a supply-side resource. The most recent Load Impact reports[33] filed with the CPUC serve as the default

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[33] To access IOU Load Impact reports, please see:

PG&E: https://www.pge.com/regulation/DemandResponseOIR/Other-Docs/PGE/2013/DemandResponseOIR_Other-Doc_PGE_20130402_269621.pdf

SCE:
http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/62A8F5E44C447F0688257B410

Footnote continued on next page

- For West LA Basin: 1x900 MW CCGT, 1x100 MW GT peaker, 50 MW storage.[39]
- For Big Creek/Ventura: 2x100 MW GT peakers.
- These resources are assumed online by 2019 and are generic resources located at existing sites. The location choice is meant to facilitate modeling ease and not prejudge where these new resources may actually be sited.
- At least 350 MW of preferred resources located in the West LA Basin and at least 50 MW of preferred resources located in Big Creek/Ventura are assumed to be procured as part of the authorization in D.13-02-015. However, there is high uncertainty as to what preferred resources will actually be procured. Therefore, the technical studies conducted in the first year of the LTPP cycle will not speculate on these preferred resources and not include them. In the second year of the LTPP cycle, these preferred resources will be modeled when revisiting technical studies to fill any needs. These preferred resources will be modeled first before any additional resources are considered to fill needs. The latest information from the SCE Request For Offers process to procure preferred resources shall inform how these preferred resources are modeled in the second year of the LTPP cycle.

The transmission projects approved by the CAISO Board in the 2013-14 TPP shall be included in all planning scenarios. The transmission projects approved by the CAISO Board in the 2014-15 TPP are expected to inform any analyses in the second year of the LTPP cycle (2015) on how to fill any needs.

The pending Track 4 decision from the 2012 LTPP cycle is also expected to issue an authorization to procure new resources. At this time, the decision is not final and the mix of resources to be authorized is unknown. Therefore, speculating on

[39] The 50 MW storage amount is listed here for convenience, but should not be separately modeled as part of D.13-02-015 assumptions. The 50 MW storage amount is already counted under the assumption for achievement of the storage procurement target in D. 13-10-040, and should not be double counted.

EXHIBIT PE-19

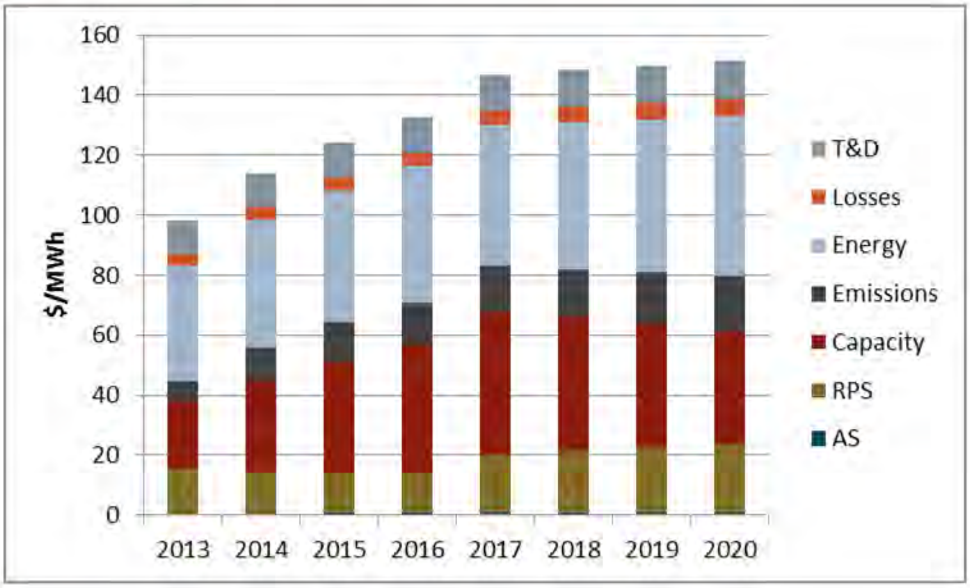
California Public Utilities Commission

California Net Energy Metering Ratepayer Impacts Evaluation

October 2013

Figure 14, below, shows the value of each component of avoided cost over time for the combined NEM output shape in the Base Case assumptions. Note the evolving relative importance of each component of the avoided costs over time.

Figure 14: Average NEM Avoided Costs by Component



4.3.1 TOTAL AVOIDED COST

Table 21 shows the total avoided cost of the Export Only case in millions of 2012 dollars in the year 2020. As with bill savings, the higher percentage of exported DG generation for the residential class is evident in the class's larger share of total avoided costs relative to the All Generation case.

EXHIBIT PE-20

Powers Engineering

February 23, 2015

California Energy Commission
Dockets Office, MS-4
Docket No. 09-RENEW EO-01
1516 Ninth Street
Sacramento, CA 95814-5512
e-mail: docket@energy.ca.gov

Subject: Powers Engineering Comment Letter on Draft DRECP NEPA/CEQA

A major flaw in the draft DRECP and DEIR/EIS ("DRECP") is the failure to include a behind-the-meter local solar alternative as the "no action" alternative to the targeted renewable energy generation levels in the DRECP study area for utility-scale solar, utility DG solar, and wind power. The local solar "no action" alternative is the most likely scenario given: current behind-the-meter solar installation rates of more than 1,000 MW per year, the cost-competitiveness of behind-the-meter solar compared to utility power with or without net-metering, state law mandating that the CPUC support sustained growth of behind-the-meter solar installations through appropriate rate design after net-metering expires, and the state's ongoing commitment to smart grid modernization of the existing distribution grid to allow it to fully accept two-way power flows and eliminate distribution grid reliability issues as a brake on customer-provided local solar development. In addition, the local solar "no action" alternative would eliminate the $140 billion life-of-project cost and environmental impact of 13 to 14 new 500 kV transmission lines assumed in all DRECP scenarios.

I. Proposed 500 kV transmission build-out will add $90 per megawatt-hour to DRECP solar and wind cost of generation

The DRECP assumes a need for new transmission lines to deliver about 14,000 MW for all alternatives. This 14,000 MW would be delivered over 13 to 14 500 kV transmission lines, depending on the alternative, as shown in Table 1.

Table 1. Number of new 500 kV lines projected for each DRECP scenario[1]

Alternate 1	Alternate 2	Alternate 3	Alternate 4	Alternate 5	No Action
14	14	14	14	13	14

The DRECP also identified a representative 500 kV line, SDG&E's 500 kV Sunrise Powerlink completed in 2012, as having a capacity of 1,200 MW.[2] The 2006 application for the Sunrise Powerlink estimated an initial capital cost of $1.265 billion and a 40-year life of project cost of

[1] Draft DRECP and EIR/EIS, *Appendix K – DRECP Transmission Technical Group Report Conceptual Transmission Plan for DRECP Alternatives*, October 2013, pp. 29-33.
[2] Ibid, p. 1.

$6.96 billion in 2010 dollars.[3] The Sunrise Powerlink capital cost approved by the California Public Utilities Commission in 2008 was $1.883 billion in 2012 dollars.[4] Extrapolating from the ratio of capital cost to the 40-year life-of-project cost Sunrise Powerlink application, the approximate life-of-project cost of the Sunrise Powerlink will be $10 billion in 2012 dollars.[5]

Assuming fourteen 500 kV lines equivalent in cost to the Sunrise Powerlink are built to deliver renewable energy generated in the DRECP study area, the total 40-year life-of-project cost will be approximately: 14 x $10 billion = 140 billion in 2012 dollars. This is equivalent to $3.5 billion per year in new transmission-related expenses.[6]

The total nameplate capacity of utility-scale solar thermal and solar PV, utility DG solar, and wind power in the DRECP preferred alternative is 14,453 MW. Assuming all of this utility-scale solar thermal and solar PV, utility DG solar, and wind power flow over the new 500 kV lines, the annual generation will be 40 million megawatt-hours (MWh) per year.[7] The unit cost of this new 500 kV transmission would be approximately $90 per MWh of DRECP renewable energy delivered, or $0.09 per kilowatt-hour (kWh) for every kWh delivered.[8]

II. Low cost of rooftop solar/parking lot solar will drive continued growth after net metering ends in 2016 or 2017

The California Energy Commission (CEC) assumes that the state will see a dramatic reduction in rooftop solar installations with the end of the California Solar Initiative and net metering.[9] The CEC projects behind-the-meter solar capacity additions dropping from a peak of about 700 MW in 2013 to 440 MW in 2014, 189 MW in 2015, 234 MW in 2016, and 99 MW in 2017.[10] The CEC forecasts a 10-year customer solar average capacity addition, from 2015 through 2024, of 222 MW per year.[11] The CEC projection, finalized in January 2014, does not take into account the much higher AB 327 net-metering solar targets signed into law in October 2013.[12]

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[3] SDG&E, *Sunrise Powerlink Transmission Project Purpose and Need - Volume 2*, Application No. 05-12-014, p. V-11. "Based on these estimates, SDG&E believes the cost of constructing the Sunrise Powerlink will be $1.265 billion. . . Assuming a 40-year project life and Operating & Maintenance ("O&M") costs of $10 million per year (in 2010 dollars), the levelized annual costs of the project are estimated at $174 million." 40 years × $174 million per year = $6.96 billion.

[4] CPUC Decision 08-12-058, *Decision Granting a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project*, December 18, 2008, p. 293. "Order No. 6: A cost cap of $1.883 billion ($2012) is adopted for the Final Environmentally Superior Southern Route."

[5] $1.883 billion × ($6.96 billion ÷ $1.265 billion) = $10.36 billion.

[6] $140 billion ÷ 40 years = $3.5 billion per year.

[7] Draft DRECP and EIR/EIS, *Appendix F2 - Megawatt Hours and Solar Technology Distribution*, August 2014, p. F2-5. Utility-scale solar generation = 25,877,613 MWh per year, utility DG solar generation = 5,195,561 MWh per year wind generation = 8,983,772 MWh per year. Total annual production = 40,056,946 MWh per year.

[8] $3.5 billion per year ÷ $40 million MWh per year = $88/MWh.

[9] CEC, *California Energy Demand 2014-2024 Final Forecast Mid-Case Final Baseline Demand Forecast Forms*, November 19, 2013, STATEWIDE Mid.xls, STATEWIDE Form 1.2-Mid, "PV" column: http://www.energy.ca.gov/2013_energypolicy/documents/demand-forecast/mid_case/

[10] Ibid.

[11] Ibid.

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

This very pessimistic DRECP customer self-generation solar projection appears to be the primary basis for the DRECP base case customer solar assumption of 10,000 MW in 2040. The CEC presumes that net metering is critical to the financial viability of customer-owned solar, and that the imminent phase-out of net metering will result in a dramatic retrenchment of rooftop and parking lot solar installations. This presumption is mistaken.

California's investor-owned utilities (IOUs) are in the process of meeting the California Solar Initiative (CSI) solar PV targets.[13] The IOUs were to have 1,940 MW online by December 2016, and appear to have met the CSI targets in late 2014.[14] This solar capacity is installed on the customer side of the electric meter, on rooftops and parking lots primarily, and is known as net-metered solar.

The IOUs' net-metered solar targets increased substantially with the passage of AB 327 in October 2013,[15] which enacted Public Utilities Code Section 2827(c)(4)(B) and established minimum statutory net-metering rooftop solar targets to be met by the IOUs no later than mid-2017. AB 327 increased the minimum net-metering cap of the IOUs to 5,256 MW.[16]

This is a 3,316 MW increase over the 1,940 MW CSI target established for the IOUs by the Commission. The IOUs are required by Section 2827(c)(4)(C) to report on a monthly basis their progress in meeting the new minimum solar PV targets by mid-2017.

1,000 MW of rooftop and parking lot solar capacity was added in California in 2013.[17] Approximately 1,300 MW was added in 2014.[18] At current installation rates, with about 2,000 MW of new capacity need to reach the AB 327 net-metering target of 5,256 MW, the goal will be reached by the end of 2016.

Maintaining the actual 1,300 MW self-generation solar installation rate from 2015 through 2040 would add about 34,000 MW of new solar capacity in the state.[19] This is in addition to the 3,000 MW of rooftop and parking lot solar in operation in the state at the end of 2014. This total of 37,000 MW of self-generated solar power in 2040 is far beyond the 10,000 MW of non-utility solar power assumed in the DRECP base case.

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

[14] B. Del Chiaro, CALSEIA e-mail to B. Powers, February 17, 2015, regarding capacity of rooftop solar installed in 2014. At least a 25 30 percent increase over 2013 (when ~1,000 MW_{ac} of net-metered solar installed), final numbers still pending.

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

[16] Public Utilities Code Section 2827(c)(4)(B): http://www.leginfo.ca.gov/cgi-bin/displaycode?section=puc&group=02001-03000&file=2821-2829. SDG&E net-metering target = 607 MW. SCE net-metering target = 2,240 MW. PG&E net-metering target = 2,409 MW. Total of the three IOUs = 5,256 MW.

[17] Renewable Energy World, *California Blows the Lid off Solar Records Installing 1GW of Rooftop Solar in 2013*, January 23, 2014.

[18] B. Del Chiaro, CALSEIA e-mail to B. Powers, February 17, 2015, regarding capacity of rooftop solar installed in 2014. At least a 25 30 percent increase over 2013 (when ~1,000 MW_{ac} of net-metered solar installed), final numbers still pending. 1,000 MW + (0.30 × 1,000 MW) = 1,300 MW.

[19] 1,300 MW-year × 26 years = 33,800 MW.

37,000 MW of self-generated solar power is 27,000 MW more customer self-generated solar power than assumed in the DRECP base case. This amount of customer solar would completely substitute for the utility-scale solar thermal, utility-scale solar PV, utility-scale DG solar, and wind power in the DRECP base case scenario, and provide over 4,000 MW of additional customer solar output.[20,21]

This scenario is also highly likely to occur unless the CPUC authorizes self-generation solar contracts at rates that are well below what the CPUC has already determined the self-generation solar is worth. This will not happen if CPUC follows state law:[22]

> In developing the standard contract or tariff, the commission shall do all of the following:
>
> (1) Ensure that the standard contract or tariff made available to eligible customer-generators ensures that customer-sited renewable distributed generation continues to grow sustainably and include specific alternatives designed for growth among residential customers in disadvantaged communities.

Customer-sited renewable distributed generation cannot continue to grow sustainably unless the contract rate makes it economic to do so, and state law requires the CPUC to establish contract terms that result in growth in the rate of customer-side solar installations.

III. CPUC estimates rooftop solar is worth about $0.12/kwh now and $0.15/kWh in 2017

The CPUC sets the rates charged by the state's IOUs. It has determined the avoided cost of self-generated rooftop and parking lot solar is approximately $0.12/kWh in 2015.[23] This avoided

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[20] Draft DRECP and EIR/EIS, *Appendix F2 - Megawatt Hours and Solar Technology Distribution*, August 2014, p. F2-5. Utility-scale solar generation = 25,877,613 MWh per year, utility DG solar generation = 5,195,561 MWh per year wind generation = 8,983,772 MWh per year. Total annual production = 40,056,946 MWh per year.

[21] Customer solar production = 1,752 kWh per year per kW_{ac}, or 1,752 MWh per year per MW_{ac}. Total quantity of customer solar necessary to offset DRECP utility solar and wind power = (40,056,946 MWh per year ÷ 1,752 MWh per year per MW_{ac}) = 22,864 MW_{ac}. The DRECP base case scenario assumes 10,000 MW_{ac} of customer solar. Therefore, amount of additional customer solar production beyond that necessary to displace DRECP utility-scale solar and wind = 37,000 MW_{ac} − 22,864 MW_{ac} − 10,000 MW_{ac} = 4,136 MW_{ac}.

[22] Public Utilities Code Section 2827.1(b): http://www.leginfo.ca.gov/cgi-bin/displaycode?section=puc&group=02001-03000&file=2821-2829. Notwithstanding any other law, the commission shall develop a standard contract or tariff, which may include net energy metering, for eligible customer-generators with a renewable electrical generation facility that is a customer of a large electrical corporation no later than December 31, 2015. The commission may develop the standard contract or tariff prior to December 31, 2015, and may require a large electrical corporation that has reached the net energy metering program limit of subparagraph (B) of paragraph (4) of subdivision (c) of Section 2827 to offer the standard contract or tariff to eligible customer-generators. A large electrical corporation shall offer the standard contract or tariff to an eligible customer-generator beginning July 1, 2017, or prior to that date if ordered to do so by the commission because it has reached the net energy metering program limit of subparagraph (B) of paragraph (4) of subdivision (c) of Section 2827. The commission may revise the standard contract or tariff as appropriate to achieve the objectives of this section. In developing the standard contract or tariff, the commission shall do all of the following:
(1) Ensure that the standard contract or tariff made available to eligible customer-generators ensures that customer-sited renewable distributed generation continues to grow sustainably and include specific alternatives designed for growth among residential customers in disadvantaged communities.

cost is projected to rise to \$0.15/kWh by 2017 and stay relatively constant at this value through 2020.[24] This is the cost that the IOUs would bear to replace the self-generated solar power if it were not being generated.

The CPUC must set rates for self-generated solar power to supersede the current net metering program when it expires.[25] It is reasonable to assume that the rate paid for self-generated solar power in a post net-metering regulatory environment will be in the range of the avoided cost that the CPUC has already calculated for self-generated solar power, or about \$0.15/kWh beginning in 2017.

IV. Production cost of commercial and residential rooftop solar will be well below \$0.15/kWh in 2017

The DOE-modeled capital cost estimate for a 10 MW solar PV project in 4th quarter 2013 was \$1,930/kW_{dc}.[26, 27] This is comparable to the \$2,000/kW_{ac} capital cost for four 10 MW solar PV projects in New Mexico announced in June 2014.[28] Solar PV contracts are being signed in 2014 at power purchase agreement (PPA) prices less than \$50/MWh.[29]

Table 2 summarizes DOE capital cost projections for rooftop and utility-scale solar PV. DOE forecasts that capital cost will decline to as low as \$1,300/kW_{dc} for systems 5 MW and up by 2016, as low as 1,500/kW_{dc} for rooftop systems by 2016.[30] Reported system prices of residential and commercial PV systems declined 6 to7 percent per year, on average, from 19982013, and by 12 to 15 percent from 20122013, depending on system size.[31] The 2016 forecast capital cost ranges shown in Table 2 are consistent with this historic solar PV price decline rate.[32]

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23 California Public Utilities Commission, *California Net Metering Ratepayer Impacts Evaluation*, October 28, 2013, Figure 14, p. 57.
24 Ibid, Figure 14, p. 57.
25 Public Utilities Code Section 2827.1(b).
26 U.S. DOE, *Photovoltaic System Pricing Trends Historical, Recent, and Near-Term Projections 2014 Edition*, September 22, 2014, p. 22.
27 DNV KEMA Energy & Sustainability, *Austin Energy Review of Strategic Plan for Local Solar in Austin*, prepared for Austin Energy, November 22, 2013, p. 8, p. 10, and p. 16. Utility-scale solar $\geq$ 5 MW has an assumed dc-to-ac conversion of 90 percent. Therefore a \$1,930/kW_{dc} utility-scale solar capital cost equals a kW_{ac} cost of: \$1,930/kW_{dc} ÷ 0.9 = \$2,144/kW_{ac}.
28 Energy Prospects West, *PNM to Build Four Solar Projects Next Year*, June 10, 2014. PNM will build four 10-MW photovoltaic solar power projects in 2015 . . . The four projects, which will cost \$79 million to build.
29 GreenTech Media, *Cheapest solar ever? Austin Energy buys at 5 cents per kWh*, March 10, 2014.
30 U.S. DOE, *Photovoltaic System Pricing Trends Historical, Recent, and Near-Term Projections 2014 Edition*, September 22, 2014, pp. 27-28.
31 Ibid, p. 4.
32 Ibid, p. 24. Germany average residential PV installed price in 2013 was \$2.05/W_{dc}. Hardware costs are fairly similar between the U.S. and Germany. Therefore the gap in total installed prices must reflect differences in soft costs (including installer margins). The German residential PV system cost is reflective of a potential for near-term installed price reductions in the U.S.

Table 2. DOE current and projected capital costs for rooftop and utility-scale (≥ 5 MW) solar PV projects[33]

Type of solar PV	2014 modeled capital cost ($\$/kW_{dc}$)	2016 forecast best-case & mid-point capital cost ($\$/kW_{dc}$)	2016 forecast in $\$/kW_{ac}$ with DC-to-AC conversion[34]
Residential rooftop	3,290	1,500 □2,250	1,765 □2,647
Commercial rooftop	2,540	1,500 □2,250	1,765 □2,647
Utility-scale, 5 MW	2,030	1,300 □1,625	1,444 □1,806

The U.S. Energy Information Administration identifies a fixed O&M cost for solar projects of $27.75/kW-yr.[35]

The current federal solar investment tax credit (ITC) for solar projects, through 2016, is 30 percent.[36] This means that 30 percent of the gross capital cost of the solar project can be deducted from taxes owed the federal government. The ITC will drop from 30 percent to 10 percent after 2016 for commercial and utility-scale projects.[37] The ITC will be eliminated for residential projects.[38] In addition to the ITC, commercial and utility solar projects are also eligible for accelerated depreciation of the net capital cost of the solar project after deducting the ITC. Accelerated depreciation has the effect of reducing the net capital cost by an additional 28 percent when the ITC is 30 percent.[39] Accelerated depreciation will reduce the net capital cost by 36 percent when the ITC is reduced to 10 percent.[40]

The 2016 production cost of residential rooftop solar, commercial rooftop solar, and utility-scale (> 5 MW) solar, based on DOE projections of best-in-class and mid-range capital, are provided in Table 3. These costs are provided with the current ITC of 30 percent and the post-2016 ITC of 10 percent. The calculations supporting these cost ranges are provided in **Attachment A**.

[33] Ibid, p. 4, p. 22 (5 MW system at $2.03/W),
[34] DNV KEMA Energy & Sustainability, *Austin Energy Review of Strategic Plan for Local Solar in Austin*, prepared for Austin Energy, November 22, 2013, p. 8, p. 10, and p. 16. For residential and commercial rooftop -scale solar, the dc-to-ac conversion is assumed to be 85 percent. Utility-scale solar ≥ 5 MW has an assumed dc-to-ac conversion of 90 percent.
[35] U.S. EIA, *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants*, April 2013, Table 1, p. 6.
[36] DNV KEMA Energy & Sustainability, *Austin Energy Review of Strategic Plan for Local Solar in Austin*, prepared for Austin Energy, November 22, 2013, p. 8 and p. 10,
[37] Ibid, p. 8 and p. 10.
[38] Solar investment tax credit description: http://www.seia.org/policy/finance-tax/solar-investment-tax-credit.
[39] Net capital cost after deducting the 30 percent ITC = 1.0 □0.3 = 0.7. Corporate tax rate is 40 percent. Therefore accelerated depreciation will reduce net capital cost by: 0.7 × 0.4 = 0.28 (28 percent).
[40] Net capital cost after deducting the 10 percent ITC = 1.0 □0.1 = 0.9. Corporate tax rate is 40 percent. Therefore accelerated depreciation will reduce net capital cost by: 0.9 × 0.4 = 0.36 (36 percent).

Table 3. Production cost with 30 percent ITC through 2016 (all solar projects), 10 percent ITC post 2016 (commercial/utility-scale projects), 0 percent ITC post 2016 (residential)

ITC	Residential rooftop production cost range [$/kWh]	Commercial rooftop production cost range [$/kWh]	Utility-scale solar production cost range [$/kWh]
30% (thru 2016)	0.072 – 0.101	0.050 – 0.072	0.036 – 0.041
10% (post 2016)	--	0.059 – 0.081	0.042 – 0.049
0% (post 2016)	0.097 – 0.137	--	--

The post-2016 production cost of commercial rooftop and parking lot solar, at $0.06 – 0.08/kWh, will be about one-half the $0.15/kWh avoided cost in 2017 to replace this solar power as identified by the CPUC. The post-2016 production cost of residential rooftop solar, at $0.097 – 0.137/kWh, will be substantially below the $0.15/kWh avoided cost. Commercial and residential customers will continue to have an economic incentive to install on-site solar after the end of net metering in California and reductions to the federal solar ITC after 2016.

It is reasonable to assume that commercial and residential rooftop solar installation rates will continue to expand in the post-2016 regulatory environment and not contract as assumed in the draft DRECP and DEIR/EIS.

Both the CEC and the draft DRECP and DEIR/EIS assume customer rooftop solar installations will come to a near halt in 2017 due to the end of net-metering and the reduction in the federal ITC for solar projects. This is a mistaken assumption not supported by evidence or current California law that requires "that the standard contract or tariff made available to eligible customer-generators ensures that customer-sited renewable distributed generation continues to grow sustainably."[41]

V. California has 100,000 MW of rooftop/parking capacity available to be developed

Approximately 3,000 MW of customer rooftop and parking lot solar had been developed in California by the end of 2014.[42,43] The estimated customer rooftop and parking lot solar resource potential in California is in the range of 100,000 MW.

Navigant Consulting, under contract to the CEC,[44] determined in 2007 that California will have about 170,000 MW of total residential rooftop solar potential in 2016, and about 40,000 MW of

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[41] Public Utilities Code Section 2827.1(b).

[42] Renewable Energy World, *California Blows the Lid off Solar Records Installing 1GW of Rooftop Solar in 2013*, January 23, 2014. "California is closing out the year with more than 2,000 MW of rooftop solar systems installed statewide."

[43] B. Del Chiaro, CALSEIA e-mail to B. Powers, February 17, 2015, regarding capacity of rooftop solar installed in 2014. "At least a 25 – 30 percent increase over 2013 (when ~1,000 MW_{ac} of net-metered solar installed), final numbers still pending." 1,000 MW + (0.30 × 1,000 MW) = 1,300 MW.

total commercial rooftop solar potential in 2016. Of these amounts, Navigant assumes only 22 to 27 percent of residential rooftop potential can be developed, and only 60 to 65 percent of the commercial rooftop potential can be developed. This reduces California-wide 2016 rooftop "technical" solar potential to 42,181 MW of residential rooftop solar and 25,708 MW of commercial rooftop solar, a total of approximately 68,000 MW.[45]

Commercial parking lot solar is another major category of customer-side distributed solar. Powers Engineering estimates total commercial parking lot potential in California at 158,000 MW based on data developed at UCLA on number and area of commercial parking spaces per capita in California. Assuming 25 percent of this parking lot potential is relatively free of shading, the net amount of commercial parking lot space that can be developed in California based on the California population in July 2013 is approximately 40,000 MW. See **Attachment B** for commercial parking lot solar potential supporting calculations.

The combined absolute potential of California residential rooftop solar, commercial rooftop solar, and commercial parking lot solar in 2016, assuming no shading, building orientation, or rooftop obstruction impediments, would be approximately 370,000 MW. The combined 2016 technical potential of these three categories of customer-side distributed solar resources, taking into consideration reasonable assumptions regarding shading, building orientation, and rooftop obstructions, is about 108,000 MW.

VI. The distribution grid is undergoing modernization for full two-way flow capability on all distribution circuits

The state' s IOUs have had a grid modernization effort underway for many years. Even without this modernization effort, the distribution grid can accept large amounts of customer solar without causing safety equipment such as circuit breakers, relays, and reclosers, to "see" reverse flow on the circuit caused by rooftop solar as a fault condition and affect grid reliability.

As a component of the DG feed-in tariff development process in 2009, the CPUC Energy Division requested data on peak loads at all distribution substations from the IOUs and compiled that information graphically as shown in Figure 1. According to the CPUC, this data was obtained from IOU distribution engineers.[46] The Energy Division staff opined that because solar is a daytime resource, it was very unlikely that the load on any given distribution substation would be less than 30 percent of peak load when solar power is being generated.

This means that a distribution substation with a 50 MW peak load will have a load of at least 15 MW during the time period when solar power is being produced. Therefore at least 15 MW of distributed solar could be fed to the distribution substation without reversing the normal one-way

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[44] Navigant, *California Rooftop Photovoltaic (PV) Resource Assessment and Growth Potential by County*, PIER Final Project Report, September 2007, APPENDIX B: RESULTS, Table B.1: Technical Potential by County (MWp), p. B-2 and p. B-3.

[45] Ibid,

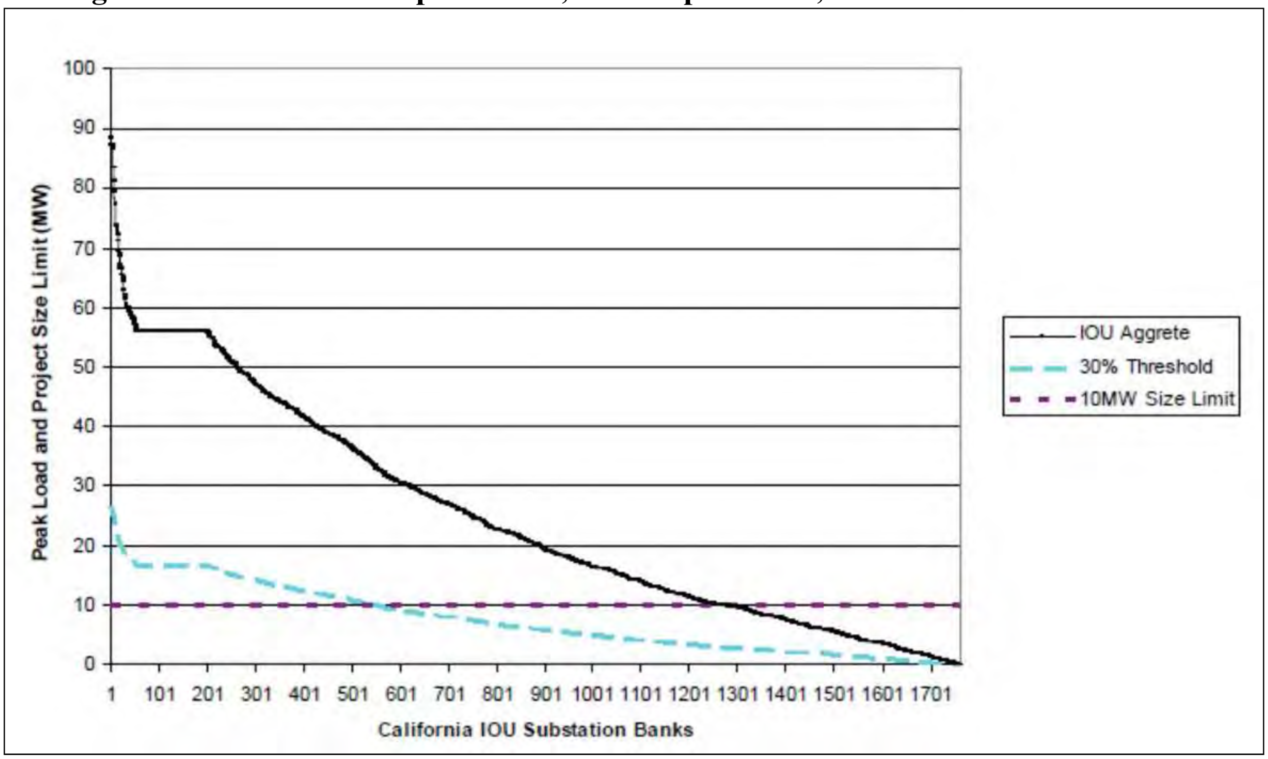
[46] CPUC Rulemaking R.08-08-009 – California RPS Program, Administrative Law Judge's Ruling on Additional Commission Consideration of a Feed-In Tariff, *Attachment A - Energy Division FIT Staff Proposal*, March 27, 2009, pp. 15-16.

flow from the distribution substation and causing older analog protective devices, circuit breakers or relays, to see the flow reversal as a fault condition.

A minimum of approximately 13,300 MW of PV can be connected directly to IOU substation load banks without concern for flow reversal based on the data in Figure 1. The supporting calculations for this estimate are provided in Table 4. The minimum may in fact be much higher, as individual distribution substations and associated circuits may have much higher minimum daylight loads than 30 percent of peak load.

The IOUs provide about two-thirds of electric power supplied in California, with publicly-owned utilities like the Los Angeles Department of Water & Power and the Sacramento Municipal Utility District and others providing the rest.[47] Assuming the substation capacity pattern in Figure 1 is also representative of the non-IOU substations, the total California-wide PV that could be interconnected at substation low-side load banks with no substantive substation upgrades would be [13,300/(2/3)] = 19,950 MW.

Figure 1. IOU Substation peak loads, 30% of peak load, and 10 MW reference line



[47] CEC, *2007 Integrated Energy Policy Report*, December 2007, Figure 1-11, p. 27.

Table 4. Calculation of distributed PV interconnection capacity to existing IOU substations with minimal interconnection cost from data in Figure 1

Substation range	Number of substations	Calculation of distributed PV that could be interconnected with minimal substation upgrades (MW)	Total distributed PV potential (MW)
1-200	200	average peak ~60 MW x 0.30 = 18 MW	3,600
201-500	300	average peak ~45 MW x 0.30 = 13.5 MW	4,000
501-800	300	average peak ~30 MW x 0.30 = 9 MW	2,700
801-1,000	200	average peak ~20 MW x 0.30 = 6 MW	1,200
1,001-1,600	600	average peak ~10 MW x 0.30 = 3 MW	1,800
		Distributed PV total:	13,300

In sum, a minimum of approximately 20,000 MW of distributed PV interconnection capacity was available in California in 2009 that would require little or no substation upgrading to accommodate the distribution level PV.

The most recent incarnation of this grid modernization effort is known as smart grid deployment. "Smart Grid," as defined in the State of California by Senate Bill (SB) 17 (Padilla, 2009), is a fundamental change in the existing electricity infrastructure that utilizes advances in technology to create a better, safer, greener electricity supply.[48] The state's IOUs spent more than $1 billion in fiscal year 2013-2014 on smart grid relative modernization, primarily focused on distribution and transmission system modernization.[49] The CPUC describes smart grid modernization in the following manner:[50]

> Grid modernization in some form has been an ongoing practice of the utilities, where economically feasible and supported via CPUC authorization in the General Rate Case (GRC). New developments in technology, as well as direction from regulators, have emphasized some trends.
>
> The accelerating adoption of customer-side intermittent renewable generation, primarily solar and wind has produced new operational challenges for the grid. In addition, greatly increased small-scale distributed generation is creating more pressure on utilities to change their business models to provide "plug and play" support for these resources. Providing an infrastructure platform for customer choice is becoming a priority.
>
> The new distribution resources planning effort now underway will guide new investment requests in future GRCs to meet these challenges. Distribution Resources Plans will enable much greater use of distributed energy resources (DER) than traditional processes have previously allowed.

48 CPUC, *Annual Report to the Governor and the Legislature California Smart Grid per Senate Bill 17 (Padilla, 2009)*, January 2015.
49 Ibid, p. 2.
50 Ibid, p. 3.

The state' s utilities are required to file Distribution Resources Plan applications by July 2015.[51] Distribution Resource Plan implementation by the utilities will require greater situational awareness, monitoring and control sensors and systems to support high penetrations of DER. Investment to support further development of these systems is now required. GRC cycles have begun to incorporate more spending on automation and grid enhancements to further the Smart Grid goals.

Safety hardware on the distribution grid, such as circuit breakers and reclosers, are being methodically replaced with microprocessor-based equivalents that all full two-way power flow on the distribution system. For example, PG&E states in its 2014 Smart Grid Annual Report that 65 percent of its 2,102 distribution circuits are equipped with automation or remote control equipment.[52] What this means in lay terms is that these circuits are capable of full two-way flow, with no restrictions on the amount of customer on-site solar due to the limitations of safety hardware on the distribution circuit or at the distribution substation.

PG&E also states that it will achieve 100 percent visibility and control of all critical distribution substation breakers by 2018, adding or replacing supervisory control and data acquisition (SCADA) for approximately 393 substations and approximately 1,107 breakers.[53] At this pace of grid modernization, full two-way flow capability on the distribution system will not be an obstacle to rapid expansion of customer solar in California.

SCE notes in its 2014 Smart Grid Annual Report on the new energy storage procurement targets the IOUs must meet:[54]

> The (October 2013 CPUC energy storage) decision established the policies and mechanisms for procurement of electric energy storage pursuant to AB 2514, setting an energy storage procurement target for the IOUs of 1,325 MW by 2020. Furthermore, the decision directs the IOUs to file separate applications containing a proposal for their first energy storage procurement period by March 1, 2014. SCE submitted its Application of its 2014 Energy Storage Procurement Plan and associated testimony on February 28, 2014.

Large amounts of storage on the grid will enhance the ability of the grid to manage variable resources like customer solar.

SCE also reports that as of June 30, 2013 it had 4,617 distribution circuits in operation of which 2,538 are automated with remote control switches. This means that 55 percent of these circuits can be remotely monitored and controlled through SCE' s existing distribution management system to protect critical distribution equipment, restore outages, and minimize customer

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[51] Ibid, p. 5.

[52] PG&E, *Annual Report of Pacific Gas and Electric Company (U 39 E) on Status of Smart Grid Investments Pursuant to Ordering Paragraph 15 of D. 10-06-047*, October 1, 2014, p. 77.

[53] Ibid, p. 27.

[54] SCE, *Southern California Edison Company's (U 338-E) Annual Report on the Status of Smart Grid Investments*, October 1, 2014, p. 5

minutes interrupted.[55] These microprocessor-based protective devices also facilitate two-way flow on the distribution circuit.

SDG&E underscores its leadership on smart solar inverters to facilitate much higher levels of customer solar power on the distribution grid:[56]

> SDG&E is actively engaged with manufacturers, the CPUC, and CEC to incorporate advanced functionality in inverters and mandate their adoption in California. The proposed inverters would securely communicate with utility operations systems while also potentially addressing the concerns related to the intermittency of solar generation when coupled with the right tariff incentives. In support of the implementation of smart inverters, SDG&E has worked with the other California IOUs on recommendations submitted to the CPUC through the Rule 21 proceeding.

SDG&E also reports that 79 percent of its distribution circuits equipped with automation or remote control equipment, including SCADA systems.[57] In lay English, this means these distribution circuits are fully capable of handling two-way power flows.

The DRECP relies on the following unsupported and obsolete statements about the current status of the distribution grid as the basis for not including a behind-the-meter customer solar alternative:

> Page II.8-7: □*For a variety of reasons (e.g., upper limits on integrating distributed generation into the electric grid, cost, lack of electricity storage in most systems, and continued dependency of buildings on grid-supplied power), distributed energy generation alone cannot meet the goals for renewable energy development.*□

> Page II.8-7: □*Integration and reliability concerns were highlighted due to local renewable generation being sent to the grid through power lines and equipment that were primarily designed to transport energy in the opposite direction. Unless managed appropriately, the integration of local renewable energy can impact the safe and reliable operation of distribution grids.*□

Upper limits on integrating distributed generation into the electric grid are rapidly disappearing as a result of utility distribution grid modernization programs. The DRECP targets are for 2040. California' s utilities have been mandated to modernize the grid to accept large inflows of local solar power feeding into distribution circuits. Utility customers are spending over $1 billion per year to accomplish the necessary modernization upgrades. It would appear, based on the most recent IOU smart grid annual reports, that each of the state' s three IOUs are more than half way toward having full two-way flow capability on all distribution circuits. It is reasonable to assume,

[55] Ibid, p. 57.
[56] SDG&E, *Annual Report of SDG&E for Smart Grid Deployments and Investments*, October 1, 2014, p. 7.

[57] Ibid, p. 94.

with the current level of investment, that the utility grid modernization effort will continue to stay in front of the expansion of customer solar power over the next 25 years.

VII. Conclusion

A major flaw in the DRECP is the failure to include a behind-the-meter local solar alternative as the "no action" alternative to the targeted renewable energy generation levels in the DRECP study area for utility-scale solar, utility DG solar, and wind power. The local solar "no action" alternative is the most likely scenario given: current behind-the-meter solar installation rates of more than 1,000 MW per year, the cost-competitiveness of behind-the-meter solar compared to utility power with or without net-metering, state law mandating that the CPUC support sustained growth of behind-the-meter solar installations through appropriate rate design after net-metering expires, and the state' s ongoing commitment to smart grid modernization of the existing distribution grid to allow it to fully accept two-way power flows and eliminate distribution grid reliability issues as a brake on customer-provided local solar development. In addition, the local solar "no action" alternative would eliminate the $140 billion life-of-project cost and environmental impact of 13 to 14 new 500 kV transmission lines assumed in all DRECP scenarios.

Submitting by:

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Attachment A: Cost of Generation, Commercial, Residential, and Utility-Scale Solar

B. Powers, Powers Engineering, February 22, 2015

I. Commercial rooftop and parking lot solar, cost of generation

Assumptions:

- Annual average fixed array, behind-the-meter capacity factor (CF): 0.20
- Average annual production per kW_{ac} of capacity at CF of 0.20: 1 kW_{ac} × 8,760 hr/yr × 0.20 = 1,752 kWh/yr
- Commercial rooftop solar 2016 DOE best-in-class gross capital cost: $\$1,765/kW_{ac}$
- Commercial rooftop solar 2016 DOE mid-range gross capital cost: $\$2,647/kW_{ac}$
- Commercial solar federal income tax credit (ITC) through 2016:[1] 30 percent
- Commercial solar federal ITC after 2016:[2] 10 percent
- Net capital cost when adjusted for accelerated depreciation, commercial solar: (net capital cost after ITC) × (corporate tax rate)
- Tax rate used to calculate value of accelerated depreciation:[3] 40 percent
- Capital recovery factor, 5 percent interest, 20-year term:[4,5] 0.0802
- Residential rooftop solar 2016 DOE best-in-class gross capital cost; $\$1,765/kW_{ac}$
- Residential rooftop solar 2016 DOE mid-range gross capital cost: $\$2,647/kW_{ac}$
- Residential solar federal income tax credit (ITC) through 2016: 30 percent
- Residential solar federal ITC after 2016:[6] 0 percent
- Net capital cost when adjusted for accelerated depreciation, residential solar: No change, not eligible to use accelerated depreciation

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[1] Solar investment tax credit description: http://www.seia.org/policy/finance-tax/solar-investment-tax-credit
[2] Ibid.
[3] Corporate tax rates, all countries: http://www.kpmg.com/global/en/services/tax/tax-tools-and-resources/pages/corporate-tax-rates-table.aspx
[4] Representative commercial construction loan interest rate, ~5% interest, 15-20 year term: https://www.commercialloandirect.com/commercial-rates.php#ConstructionLoanInterestRates.
[5] M. Lindeburg, *Mechanical Engineering Review Manual 6th Edition, Chapter 2: Engineering Economy*, 1980, p. 2-26
[6] Solar investment tax credit description: http://www.seia.org/policy/finance-tax/solar-investment-tax-credit.

A. Through 2016, with 30 percent ITC and accelerated depreciation – best in class 2016 DOE forecast capital cost:

Gross capital cost, $[\$/\mathrm{kW}_{ac}]$	Net capital cost – 30% ITC, $[\$/\mathrm{kW}_{ac}]$	Net capital cost, adjust for accelerated depreciation, $[\$/\mathrm{kW}_{ac}]$	Annualized net capital cost, at 5% interest, 20 years, $[\$/\mathrm{kW}_{ac}\text{-yr}]$	O&M cost, $[\$/\mathrm{kW}_{ac}\text{-yr}]$	Total annual cost, capital + O&M, $[\$/\mathrm{kW}_{ac}]$	Cost of generation, @ 1,752 kWh-yr per kW_{ac} [$/kWh]
1,765	1,236	741	59.43	27.75	87.18	0.050

B. Through 2016, with 30 percent ITC and accelerated depreciation – mid-range 2016 DOE forecast capital cost:

Gross capital cost, $[\$/\mathrm{kW}_{ac}]$	Net capital cost – 30% ITC, $[\$/\mathrm{kW}_{ac}]$	Net capital cost, adjust for accelerated depreciation, $[\$/\mathrm{kW}_{ac}]$	Annualized net capital cost, at 5% interest, 20 years, $[\$/\mathrm{kW}_{ac}\text{-yr}]$	O&M cost, $[\$/\mathrm{kW}_{ac}\text{-yr}]$	Total annual cost, capital + O&M, $[\$/\mathrm{kW}_{ac}]$	Cost of generation, @ 1,752 kWh-yr per kW_{ac} [$/kWh]
2,647	1,853	1,112	89.18	27.75	126.93	0.072

C. After 2016, with 10 percent ITC and accelerated depreciation – best in class 2016 DOE forecast capital cost:

Gross capital cost, $[\$/\mathrm{kW}_{ac}]$	Net capital cost – 10% ITC, $[\$/\mathrm{kW}_{ac}]$	Net capital cost, adjust for accelerated depreciation, $[\$/\mathrm{kW}_{ac}]$	Annualized net capital cost, at 5% interest, 20 years, $[\$/\mathrm{kW}_{ac}\text{-yr}]$	O&M cost, $[\$/\mathrm{kW}_{ac}\text{-yr}]$	Total annual cost, capital + O&M, $[\$/\mathrm{kW}_{ac}]$	Cost of generation, @ 1,752 kWh-yr per kW_{ac} [$/kWh]
1,765	1,588	953	76.43	27.75	104.18	0.059

D. After 2016, with 10 percent ITC and accelerated depreciation □mid-range 2016 DOE forecast capital cost:

Gross capital cost, $[\$/\text{kW}_{ac}]$	Net capital cost □10% ITC, $[\$/\text{kW}_{ac}]$	Net capital cost, adjust for accelerated depreciation, $[\$/\text{kW}_{ac}]$	Annualized net capital cost, at 5% interest, 20 years, $[\$/\text{kW}_{ac}\text{-yr}]$	O&M cost, $[\$/\text{kW}_{ac}\text{-yr}]$	Total annual cost, capital + O&M, $[\$/\text{kW}_{ac}]$	Cost of generation, @ 1,752 kWh-yr per kW_{ac} [$/kWh]
2,647	2,382	1,429	114.61	27.75	142.36	0.081

II. Residential rooftop solar, cost of generation

A. Through 2016, with 30 percent ITC, no accelerated depreciation □best in class 2016 DOE forecast capital cost:

Gross capital cost, $[\$/\text{kW}_{ac}]$	Net capital cost □30% ITC, $[\$/\text{kW}_{ac}]$	Net capital cost, adjust for accelerated depreciation, $[\$/\text{kW}_{ac}]$	Annualized net capital cost, at 5% interest, 20 years, $[\$/\text{kW}_{ac}\text{-yr}]$	O&M cost, $[\$/\text{kW}_{ac}\text{-yr}]$	Total annual cost, capital + O&M, $[\$/\text{kW}_{ac}]$	Cost of generation, @ 1,752 kWh-yr per kW_{ac} [$/kWh]
1,765	1,236	NA	99.13	27.75	126.88	0.072

NA = not applicable

B. Through 2016, with 30 percent ITC, no accelerated depreciation □mid-range 2016 DOE forecast capital cost:

Gross capital cost, $[\$/\text{kW}_{ac}]$	Net capital cost □30% ITC, $[\$/\text{kW}_{ac}]$	Net capital cost, adjust for accelerated depreciation, $[\$/\text{kW}_{ac}]$	Annualized net capital cost, at 5% interest, 20 years, $[\$/\text{kW}_{ac}\text{-yr}]$	O&M cost, $[\$/\text{kW}_{ac}\text{-yr}]$	Total annual cost, capital + O&M, $[\$/\text{kW}_{ac}]$	Cost of generation, @ 1,752 kWh-yr per kW_{ac} [$/kWh]
2,647	1,853	NA	148.61	27.75	176.36	0.101

NA = not applicable

C. After 2016, with 10 percent ITC, no accelerated depreciation □best in class 2016 DOE forecast capital cost:

Gross capital cost, [\$/kW_{ac}]	Net capital cost □0% ITC, [\$/kW_{ac}]	Net capital cost, adjust for accelerated depreciation, [\$/kW_{ac}]	Annualized net capital cost, at 5% interest, 20 years, [\$/kW_{ac}-yr]	O&M cost, [\$/kW_{ac}-yr]	Total annual cost, capital + O&M, [\$/kW_{ac}]	Cost of generation, @ 1,752 kWh-yr per kW_{ac} [\$/kWh]
1,765	1,765	NA	141.55	27.75	169.30	0.097

NA = not applicable

D. After 2016, with 10 percent ITC, no accelerated depreciation □mid-range 2016 DOE forecast capital cost:

Gross capital cost, [\$/kW_{ac}]	Net capital cost □0% ITC, [\$/kW_{ac}]	Net capital cost, adjust for accelerated depreciation, [\$/kW_{ac}]	Annualized net capital cost, at 5% interest, 20 years, [\$/kW_{ac}-yr]	O&M cost, [\$/kW_{ac}-yr]	Total annual cost, capital + O&M, [\$/kW_{ac}]	Cost of generation, @ 1,752 kWh-yr per kW_{ac} [\$/kWh]
2,647	2,647	NA	212.29	27.75	240.04	0.137

NA = not applicable

III. Utility-scale solar (≥ 5 MW), cost of generation

- Annual average utility-scale solar DRECP capacity factor (CF), 2,150 hr of 8,760 hr/yr: 0.245
- Average annual production per kW_{ac} of capacity at CF of 0.245: 1 kW_{ac} × 8,760 hr/yr × 0.245 = 2,146 kWh/yr
- Commercial rooftop solar 2016 DOE best-in-class gross capital cost: \$1,444/kW_{ac}
- Commercial rooftop solar 2016 DOE mid-range gross capital cost: \$1,806/kW_{ac}
- Commercial solar federal ITC through 2016: 30 percent
- Commercial solar federal ITC after 2016: 10 percent
- Net capital cost when adjusted for accelerated depreciation, commercial solar: (net capital cost after ITC) × (corporate tax rate)
- Tax rate used to calculate value of accelerated depreciation: 40 percent
- Capital recovery factor, 5 percent interest, 20-year term: 0.0802

A. Through 2016, with 30 percent ITC and accelerated depreciation □best in class 2016 DOE forecast capital cost:

Gross capital cost, $[\$/kW_{ac}]$	Net capital cost □30% ITC, $[\$/kW_{ac}]$	Net capital cost, adjust for accelerated depreciation, $[\$/kW_{ac}]$	Annualized net capital cost, at 5% interest, 20 years, $[\$/kW_{ac}\text{-yr}]$	O&M cost, $[\$/kW_{ac}\text{-yr}]$	Total annual cost, capital + O&M, $[\$/kW_{ac}]$	Cost of generation, @ 1,752 kWh-yr per kW_{ac} [$/kWh]
1,444	1,011	607	48.68	27.75	76.43	0.036

B. Through 2016, with 30 percent ITC and accelerated depreciation □mid-range 2016 DOE forecast capital cost:

Gross capital cost, $[\$/kW_{ac}]$	Net capital cost □30% ITC, $[\$/kW_{ac}]$	Net capital cost, adjust for accelerated depreciation, $[\$/kW_{ac}]$	Annualized net capital cost, at 5% interest, 20 years, $[\$/kW_{ac}\text{-yr}]$	O&M cost, $[\$/kW_{ac}\text{-yr}]$	Total annual cost, capital + O&M, $[\$/kW_{ac}]$	Cost of generation, @ 1,752 kWh-yr per kW_{ac} [$/kWh]
1,806	1,264	759	60.87	27.75	88.62	0.041

C. After 2016, with 10 percent ITC and accelerated depreciation □best in class 2016 DOE forecast capital cost:

Gross capital cost, $[\$/kW_{ac}]$	Net capital cost □10% ITC, $[\$/kW_{ac}]$	Net capital cost, adjust for accelerated depreciation, $[\$/kW_{ac}]$	Annualized net capital cost, at 5% interest, 20 years, $[\$/kW_{ac}\text{-yr}]$	O&M cost, $[\$/kW_{ac}\text{-yr}]$	Total annual cost, capital + O&M, $[\$/kW_{ac}]$	Cost of generation, @ 1,752 kWh-yr per kW_{ac} [$/kWh]
1,444	1,300	780	62.56	27.75	90.31	0.042

D. After 2016, with 10 percent ITC and accelerated depreciation — mid-range 2016 DOE forecast capital cost:

Gross capital cost, [$/kW$_{ac}$]	Net capital cost – 10% ITC, [$/kW$_{ac}$]	Net capital cost, adjust for accelerated depreciation, [$/kW$_{ac}$]	Annualized net capital cost, at 5% interest, 20 years, [$/kW$_{ac}$-yr]	O&M cost, [$/kW$_{ac}$-yr]	Total annual cost, capital + O&M, [$/kW$_{ac}$]	Cost of generation, @ 1,752 kWh-yr per kW$_{ac}$ [$/kWh]
1,806	1,625	975	78.21	27.75	105.96	0.049

Attachment B: Parking Lot Solar Potential in California

B. Powers, Powers Engineering, December 15, 2014

The methodology utilized to calculate the PV technical potential of ground-level parking lots and parking structures in California is shown in Table 1. A core assumption in the methodology is that only 25 percent of total estimated parking surface is sufficiently open, meaning not shaded to a significant degree, so that its full solar potential can be realized. The estimated ground-level parking lot and parking structure PV potential in California, assuming 25 percent of the total surface area is utilized for PV, is 39,500 MW_{ac}.

Table 1. Assumptions Used to Estimate PV Potential of Parking Lots □California

Assumption	Source
771 vehicles per 1,000 citizens	Dr. Donald Shoup, urban planning, UCLA[1]
At least 4 parking spaces per vehicle, one of which is residential space	Dr. Donald Shoup, urban planning, UCLA
38,332,521	July 1, 2013 California population estimate: http://quickfacts.census.gov/qfd/states/06000.html
162 square feet per parking space	Square footage of typical 9-foot by 18-foot parking space, Envision Solar, San Diego[2]
Approximately 88,663,000 non-residential parking spaces in California	Calculated value: 38,332,521 × (771/1,000) × 3 spaces [4 total spaces per car □1 residential space per car] = 88,663,000 non-residential spaces
11 W_{ac} per square foot PV capacity per square foot of parking area	Envision Solar, San Diego[3]
158,000 MW_{ac} parking lot PV theoretical potential in California without considering shading	88,663,000 spaces × 162 square feet per space × 11 W_{ac} per square feet × 1 MW_{ac} per million W_{ac} = 158,000 MW_{ac} parking lot PV potential
39,500 MW_{ac} actual potential in California	Rough estimate of actual PV potential - assumes 25 percent of non-residential parking spaces are unshaded throughout the day and full PV potential can be realized at these sites

[1] Dr. Donald Shoup, *The High Cost of Free Parking*, March 2005, published by American Planning Association, Chapter 1.
[2] Jim Trauth, Envision Solar, estimate of solar parking lot potential in San Diego County, e-mail to Bill Powers, June 13, 2007.
[3] Ibid.

EXHIBIT PE-21

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BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE
STATE OF CALIFORNIA

Application of San Diego Gas and Electric Company (U 902 M) for Authority to Partially Fill the Local Capacity Requirement Need Identified in D.14-03-004 and Enter Into a Purchase Power Tolling Agreement with Carlsbad Energy Center, LLC	A.14-07-009

**OPENING BRIEF OF
SHELL ENERGY NORTH
AMERICA (US), L.P.**

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Date: December 10, 2014

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The Commission should not assume that it is "hamstrung" by the current December 31, 2017 OTC compliance deadline, or that it must approve SDG&E's application for 600 MW of gas-fired peaking resources from the Carlsbad Energy Center in order to meet a local capacity procurement need that will arise at the end of 2017. As discussed below, the CAISO has the authority to request suspension of the OTC compliance deadline if the Encina facility is needed for local reliability. The Commission should consider whether gas-fired peaking units provide the least-cost, best-fit resources to meet the needs of the grid for system inertia, VAR support and frequency response, especially in view of the loss of SONGS.

As a result of D.14-03-004, the Commission has a unique opportunity to identify and encourage innovative capacity procurement to facilitate increased renewable energy delivery to the San Diego sub-area. SDG&E's all-source solicitation provides the opportunity for bidders to present cost-effective and operationally flexible capacity procurement options. Approval of SDG&E's proposed bilateral contract for 600 MW of gas-fired peaking generation would preempt the competitive procurement process that otherwise could result from SDG&E's RFO. The Commission should not undermine the RFO process by considering the Carlsbad Energy Center proposal outside the context of the all-source solicitation.

III.

ARGUMENT

A. <u>The Commission Should Encourage SDG&E to Engage in Balanced Capacity Procurement That is Needed to Integrate Increased Renewable Resources</u>

In order to integrate new renewable energy supplies, renewable resources must be balanced by resources that can provide frequency response and VAR support. Peaking facilities generally have a low capacity factor (are only on-line for limited time periods), resulting in very limited ability to provide VAR support. Peaking facilities also do not provide the frequency response that is needed to stabilize the grid upon the loss of a generation unit or transmission line. In addition, due to their expected low capacity factor, peakers do not provide consistent system inertia, which is the ability of a power system to support imported energy. The characteristics of peaking facilities raise serious questions about whether a PPTA for 600 MW of peaking capacity is consistent with the need to integrate increased renewable supplies into SDG&E's local reliability area.

Carlsbad Energy Center witness Valentino testified that the proposed peaking facilities will operate at a 10-20 percent capacity factor, with a maximum capacity factor of 30 percent (the limit imposed by the air permits.) Tr. 1/134, 136. CAISO witness Robert Sparks testified that when the CAISO modeled SDG&E's Track IV reliability requirement in R.12-03-014, the CAISO modeled a 558 MW combined cycle generation project in the Carlsbad area to address "numerous thermal overloads and voltage stability problems" that were identified in the absence of a facility in the Carlsbad area. Ex. 4 at p. 3. Mr. Sparks acknowledged that a combined cycle facility generally operates at a higher capacity factor than a peaking facility. Tr. 2/311. In light of Mr. Sparks' expressed concern about voltage stability and "degradation of deliverability of renewable generation in the Imperial Valley," (Ex. 4 at p. 8), it is questionable whether peaking units with a low capacity factor are the best resources to meet the local reliability need created by the loss of SONGS. SDG&E witness Baerman acknowledged that with increased reliance on renewable generation to meet the State's RPS requirements, there is an increased need for grid balancing services and ancillary services. Tr. 1/50.

CAISO witness Sparks testified that the CAISO has prepared studies showing the benefits of replacing OTC generation with "flexible" generation (peaker units and combined cycle units (Tr. 2/316)), which include "the ability to provide ancillary services" and "inertia and governor control to respond to changes in frequency and provide system stability. . . ." Ex. 4 at p. 7. Mr. Sparks explained that system inertia (coupled with governor control) responds to a "large loss of resources." Tr. 2/313.[1] Mr. Sparks acknowledged, however, that system inertia can only be provided when a generating facility is <u>on line</u>. Tr. 3/315. Because a peaker unit will operate at a capacity factor of 10 to 20 percent, a peaker unit will be unable to provide system inertia most of the time.

Similarly, Mr. Sparks alluded to the benefit of flexible generation being able to provide ancillary services such as "regulation," "ramping," "spinning reserves," and "voltage support." Tr. 2/317, 318. Mr. Sparks testified that these ancillary services reflect "the ability to ramp and control the generation output either up or down to maintain frequency, maintain line loadings, [and] voltage." Tr. 2/318. Mr. Sparks acknowledged that in order for a generation facility to provide "regulation" and "voltage support," the facility must be "on line." Tr. 2/318.

A further issue arises with respect to "overgeneration." Mr. Sparks testified that as the delivery of renewable generation increases, there are certain times of the year -- and certain times of the day -- when there is low to moderate load but a large amount of -- even too much -- solar generation. Tr. 2/319. Mr. Sparks testified that in an "overgeneration" situation, the ability of a generation facility to be off line is a "good attribute." Tr. 2/320. Mr. Sparks acknowledged, however, that pumped storage would be a better resource than a peaker unit in an overgeneration condition, because pumped storage can prevent the <u>curtailment</u> of renewable generation. Tr.

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[1] Mr. Sparks testified that when a large input of power is lost, the frequency of the system is depressed. To avoid a slowdown of frequency (and consequent load-shedding), the system operator wants "potential energy built up in the inertia of the power plants to allow the system to . . . absorb the loss of the resources. The governors allow . . . the generators themselves, the mechanical parts, to start producing more mechanical power. That turns into more electrical power to avoid this frequency drop." Tr. 2/314.

2/320. Mr. Sparks agreed that while a peaker unit has the ability to be shut off so that it is not producing, a storage facility has the ability to charge or pump water, thus preventing the curtailment of renewable generation. Tr. 2/320.

The evidence established that in a changing resource environment in which renewable projects comprise an increasing share of the supply portfolio, peaker units may not be the optimal resource to integrate these new supplies. Other resources, including pumped hydro storage, provide system inertia, VAR support and frequency response, all of which are necessary to integrate renewables and provide system stability. Furthermore, pumped storage can mitigate "overgeneration." In D.14-03-004, the Commission stated that "[w]ithin the categories that include preferred resources, bulk energy storage and large pumped hydro facilities should not be excluded." Decision at p. 102.

The Commission should consider whether 600 MW of gas-fired peaker capacity is the "best fit" resource to replace the loss of SONGS. Alternatively, it may be preferable to limit the amount of peaker capacity purchased by SDG&E in order to diversify SDG&E's local capacity portfolio with other resources, including pumped hydro storage and other capacity that can integrate renewable resources into the San Diego sub-area.

B. Reliance on a 2021-2022 In-Service Date for New Capacity Resources Will Produce a More Robust Solicitation

The Commission should not assume that the Carlsbad Energy Center is the only resource that can meet SDG&E's local capacity procurement obligation in a timely manner. Resources beyond the Carlsbad Energy Center, conventional or otherwise, alone or in combination, may be able to meet the local capacity requirements and the 2022 timeline set forth in D.14-03-004. The capability of other resources can only be determined, however, through review of the results of SDG&E's all-source RFO. In its review of the bids submitted through the RFO, SDG&E should

EXHIBIT PE-22

STATE OF CALIFORNIA EDMUND G. BROWN JR., G

PUBLIC UTILITIES COMMISSION
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March 6, 2015

Agenda ID #13794
Ratesetting

TO PARTIES OF RECORD IN APPLICATION 14-07-009

This is the proposed decision of Administrative Law Judge Yacknin. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's April 9, 2015 Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure.

/s/ KAREN V. CLOPTON
Karen V. Clopton, Chief
Administrative Law Judge

KVC:ek4
Attachment

Decision **<u>PROPOSED DECISION OF ALJ YACKNIN</u>** (Mailed on 3/6/2015)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U 902 E) for Authority to Partially Fill the Local Capacity Requirement Need Identified in D.14-03-004 and Enter into a Purchase Power Tolling Agreement with Carlsbad Energy Center, LLC.	Application 14-07-009 (Filed on July 21, 2014)

DECISION DENYING WITHOUT PREJUDICE SAN DIEGO GAS & ELECTRIC COMPANY'S APPLICATION FOR AUTHORITY TO ENTER INTO PURCHASE POWER TOLLING AGREEMENT WITH CARLSBAD ENERGY CENTER, LLC

procurement of preferred resources beyond the mandatory minimum. It will relieve SDG&E of the duty "to procure renewable generation to the fullest extent possible" once it achieves the 200 MW minimum target for preferred resources, as mandated by the Commission. Thus, a better statement of the fundamental issue before us is whether the benefit of a competitive procurement process and its potential for procuring additional preferred resources beyond the minimum required by D.14-03-004 outweighs the risk of delaying Encina's timely retirement and/or creating a reliability gap upon its retirement. We conclude that it does.

In determining SDG&E's LCR need for the planning horizon 2011 to 2020, the Commission carefully considered and accounted for the anticipated retirement of the Encina OTC units. Starting with the results of the CAISO's OTC model of its recommended base case scenario,[9] D.13-03-029 subtracted forecasted amounts of uncommitted energy efficiency, demand response, and combined heat and power resources, and determined an LCR need of 343 MW to account for the 2018 OTC retirements. In so doing, D.13-03-029 acknowledged that the OTC's modeling assumptions reflected the CAISO's statutory responsibility to consider, for transmission planning purposes, only those resources that are certain to materialize, but emphasized that the Commission's statutory responsibility requires us to ensure just and reasonable rates.

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[9] This is the same OTC model used to determine SCE's LCR need in the Track 1 decision. (D.13-02-015 at 14-15.) The OTC study evaluated the LCR for 2021 under the four Renewables Portfolio Standard (RPS) resource additions scenarios that were developed in the 2010 LTPP: the cost-constrained scenario, with 909 MW of RPS additions in the SDG&E service territory by 2020 (which the CAISO recommended as its base case); the trajectory scenario, with 508 MW; the environmentally-constrained scenario, with 317 MW; and the time-constrained scenario, with 74 MW. (*See* D.13-03-029, fn. 4.)

EXHIBIT PE-23

County of Los Angeles
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"To enrich lives through effective and caring service"

April 5, 2015

Ms. April Sommer
Staff Attorney
Center for Biological Diversity
351 California St, #600
San Francisco, CA 94104

SUBJECT: Letter of Support from the Southern California Regional Energy Network for Utilization of Preferred Resources in the Ventura County Local Capacity Requirements Region

The Southern California Regional Energy Network (SoCalREN) sends this letter of support for the efforts of the California Center for Biological Diversity (CBD), Sierra Club, City of Oxnard and Ventura County residents to explore clean energy alternatives to the installation of a natural gas-fired, peaking power plant in the Oxnard area under Application 14-11-016.

Since 2013 the SoCalREN has worked with public agencies (cities, counties and districts) to help identify and implement energy projects under the CPUC's 2013-2015 Energy Efficiency Program. The SoCalREN provides centralized, technical resources that support identification, assessment, procurement and implementation management of projects.

The SoCalREN is an informal group of cities and counties within SCE and SCG service territories that work with the County of Los Angeles who serves as the administrator of the SoCalREN.

Under this model, and specific to public agencies in Ventura County, the SoCalREN has identified a large number of both energy efficiency, solar photovoltaic, thermal energy storage and demand response opportunities in both the public and private sector. These projects have been developed through the SoCalREN's Energy Efficiency program activities, efforts to leverage the SoCalREN business model with SCE's Local Capacity Restraint Request for Offers (for Preferred Resources), and relationships between the SoCalREN and the Ventura regional community.

The "identified pipeline" of Preferred Resource projects within the public agency entities of Ventura County that would impact peak demand by 64 MW is summarized below.

- 84 confirmed (scoped) energy efficiency projects
- 10,000 kW peak demand reduction due to energy efficiency

- 76 confirmed solar photovoltaic projects
- 44,000 kW of peak project generation
- 12 confirmed demand response locations
- 10,000 kw peak demand reduction due to demand response

In addition the SoCalREN, working with local, engaged stakeholders, have identified an additional 136MW of private sector of peak demand impact projects:

- 53,000 kW of solar PV
- 14,000 kW of thermal storage
- 23,000 kW of HVAC replacements
- 28,000 kW of low income EE and HVAC
- 18,000 kW of self-generation

The SoCalREN supports the concept that locally vetted, developed and supported Preferred Resource projects should become a viable and desirable clean energy program model to mitigate or offset the development of base load or peak load thermal generation and/or the development of expanded distribution system projects. Additionally, the projects can be funded through a combination of energy efficiency program funds, utility resource procurement funds, distribution system upgrade budgets, and public/private sector funds.

SoCalREN supports the efforts of the CBD and other Ventura County stakeholders to urge the CPUC to implement a new Request for Offer that:

1. Allocates the 290 MW procurement to preferred resources
2. Allows the preferred resources in any category of renewables, EE or DR
3. Allows for sufficient time to allow stakeholders and vendors to respond, 180 days
4. Follows the approved process used in the approved Preferred Resources Pilot in Orange County
5. Provides funding for expansion of the role of the SoCalRen for private engagement
6. Defers the decision on the GHG power plant procurement until 2017

Granting these stakeholders' request would allow the SoCalREN and a variety of local, regional, public, and private participants to pursue and enroll preferred resources within a reasonable time to satisfy the CPUC and the incumbent utility requirements that viable preferred resource projects in the region can be implemented.

Sincerely,

Howard Choy
General Manager, Office of Sustainability
County of Los Angeles

CC:
Bill Powers, P.E.
Powers Engineering

EXHIBIT PE-24

Preferred Resources Pilot

EDISON INTERNATIONAL®

Providing Reliable Power from Clean Resources

Southern California Edison has begun a regional pilot to measure the impact on the grid of preferred resources – alternatives to building new gas-fired power plants. From this study, SCE hopes to develop an approach that will demonstrate that preferred resources can help meet reliability needs across SCE's service territory.
This multi-year pilot, to be conducted in a part of Orange County, will study the reliability of distributed generation (such as solar generation), energy conservation programs and energy storage. Specifically, it will address the long-term needs of the community with San Onofre Nuclear Generating Station's retirement and the pending closure of other ocean-cooled power plants. SCE is working on the pilot with business and residential customers, the California Public Utilities Commission, the California Independent System Operator, nongovernmental agencies and vendors.

The pilot will help determine the correct mix and proper timing for adding preferred resources to meet local customer demand. SCE has taken bids for preferred resources and will select those that will be added to the electrical system by late summer 2014. SCE also plans to roll out a grid-level measurement system to analyze the contribution of preferred resources.

There are several issues affecting the production of electricity in Southern California. The first is the lack of traditional power sources due to the closure of the San Onofre Nuclear Generating Station and the expected reduction in the number of large power plants operating after 2020 due to government regulations. The second is the desire of policymakers to place a priority on clean sources of energy rather than building more gas-fired generation plants.

Clean energy can come from several sources —in terms of generation (clean distributed generation), conservation (energy efficiency and demand response), and energy storage. These sources are collectively called preferred resources, and may be a suitable option to meet local electrical demands. However, the use of these sources of power also means that the electricity grid must be upgraded to transport more intermittent electric power sources than ever before.

Get Involved

Throughout the pilot region in southern Orange County, SCE business and residential customers are encouraged to sign up for programs and services that use preferred resources, especially programs** such as:

- **Automated Demand Response** — business customers may earn up to $300 per kW of pre-calculated demand response load reduction for installing technology that automatically reduces load during energy events.
- **Summer Discount Plan** — customers are rewarded for allowing their A/C to be remotely shut off during select energy events that affect their area.
- **Save Power Day** — customers can earn up to $100 annually in bill credits for reducing usage during peak periods on designated days.
- **Energy Efficiency Rebates** — installing energy efficient equipment in your home or business.

For more information on what you can do, visit:
Residential customers:
https://www.sce.com/residential/
Business customers:
https://www.sce.com/business/

More information about the Preferred Resources Pilot is available at:
http://on.sce.com/preferredresources

*** Terms and conditions apply*

EXHIBIT PE-25

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) for Approval of the Results of Its 2013 Local Capacity Requirements Request for Offers for the Moorpark Sub-Area.	Application 14-11-016 (Filed November 26, 2014)

RESPONSE OF ENERNOC, INC.

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January 12, 2015

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) for Approval of the Results of Its 2013 Local Capacity Requirements Request for Offers for the Moorpark Sub-Area.	Application 14-11-016 (Filed November 26, 2014)

RESPONSE OF ENERNOC, INC.

EnerNOC, Inc., respectfully files this Response to Application (A.) 14-11-016, Southern California Edison Company's (SCE's) application for approval of the results of its 2013 Local Capacity Requirements (LCR) Request for Offers (RFOs) for the Moorpark Sub-Area. This Response is filed and served pursuant to Rule 2.6 of the Commission's Rules of Practice and Procedure and the ALJ's Email Ruling of December 15, 2014, extending the due date for protests and responses to A.14-11-016 and a related, but unconsolidated, application (A.14-11-012) (SCE LCR RFOs Western LA Basin)) to today, January 12, 2015 (12-15-14 ALJ's Ruling).

I. SUMMARY

Rule 2.6 of the Commission's Rules of Practice and Procedure allow parties to either protest or respond to an application. A "protest" objects to the granting, in whole or in part, of the authority sought in an application; a "response" does not object to that authority, but does present information pertinent to resolving the application.[1]

By this Response, EnerNOC does not object to this application being granted. However, EnerNOC wants to raise concerns with the process that has resulted in the withdrawal of bids to offer services to SCE. Further, in compliance with Rule 2.6, this Response also describes the effect of A.14-11-016 on EnerNOC's business and EnerNOC's position on the proposed category, the issues to be considered, a proposed schedule, and the need for evidentiary hearings

[1] Commission Rules of Practice and Procedure, Rule 2.6(b) and (c).

in this application. EnerNOC also reserves the right to raise additional issues and make further recommendations pending further review of the application, the responses and protests of other parties, and any replies to those protests and responses by SCE.

II.
EFFECT OF THE APPLICATION ON ENERNOC

EnerNOC, Inc. (NASDAQ: ENOC) is a publicly traded corporation that is a leading provider of energy intelligence software (EIS). Dozens of utilities and grid operators worldwide rely upon EnerNOC applications and professional services to enhance grid reliability, and to provide cost-effective alternatives to traditional power supply resources. Thousands of enterprises use EnerNOC' s applications to bring new clarity to how they buy energy, how much they consume, and when they use it to drive operational efficiency, improve productivity, and manage energy expenses. EnerNOC's Network Operations Center (NOC) offers 24x7x365 customer support.

EnerNOC's EIS solutions for utilities help maximize customer engagement and the value of demand-side resources, including demand response and energy efficiency. EnerNOC provides DR services under contract to SCE. EnerNOC has actively participated, individually and jointly (with other similarly situated DR providers), in multiple Commission proceedings focused on utility DR programs and procurement.

As relevant to this application, EnerNOC was actively involved in the Commission' s Long Term Procurement Plan (LTPP) Rulemaking (R.) 12-03-014, in which the two decisions authorizing the procurement that is the subject of A.14-11-016 were issued, namely, Decision (D.) 13-02-015 (Track 1) and D.14-03-004 (Track 4). EnerNOC also has specific experience and knowledge of the results SCE LCR RFOs. Given the involvement and expertise of EnerNOC in the DR market in California, the Commission' s DR and LTPP proceedings, and the specific RFOs at issue here, EnerNOC intends to bring its unique perspective and experience to ongoing, active participation in A.14-11-016, especially to offer informed opinions on shortcomings and needed improvements to this RFO process.

III. RESPONSE TO APPLICATION

By Rule 2.6(b), this response identifies concerns EnerNOC has with the process for determining preferred resource eligibility for selection in the Moorpark Sub-Area RFO. Several aspects of the RFO, as it relates to DR resource eligibility requirements in order to qualify for resource adequacy, were not developed through a Commission process, and DR resource obligations, in order to qualify as a supply-side resource, are under development. Because DR is in such a significant state of transition, it is not possible to determine the competitive landscape that DR aggregators would encounter from either SCE or third-party offered services to attract customers to participate as resources, which may have high performance requirements. These uncertainties relative to DR resources created unmanageable levels of risk exposure to DR bidders.

Therefore, it is EnerNOC' s position that, for A.14-11-016, the Commission recognize and consider the following:

1. The resource requirements for resource adequacy eligibility were developed through private consultations between SCE and the California Independent System Operator (CAISO), that have not been developed through a public process in the resource adequacy docket and have not approved by the Commission;[2]

[2] SCE Testimony in support of A.14-11-016, at pp. 7-8 (SCE (Cushnie)).

2. The resource selection excluded certain resources for eligibility in meeting the local capacity requirements because CAISO failed to study whether those resources could meet the system resource adequacy requirements;[3]

3. There was incomplete information relative to competitive alternatives that DR bidders would face that made it difficult to determine the availability of customers to participate as resources or the ability to economically attract customers to participate;

4. DR resource requirements, as it relates to wholesale market participation in the CAISO's wholesale markets, are under development. Some of those existing requirements are cost-prohibitive barriers to entry. In addition, there is an inability to quantify the exposure to CAISO cost incurrence associated with SCE's bid of third-party DR resources into the wholesale market.

IV. PROPOSED CATEGORY FOR APPLICATION, NEED FOR HEARING, ISSUES TO BE CONSIDERED, AND PROPOSED SCHEDULE

Rule 2.6(d) also gives parties protesting or responding to an application the opportunity to provide comments or objections "regarding the applicant's statement on the proposed category, need for hearing, issues to be considered, and proposed schedule." An "alternative schedule" can also be proposed.[4]

EnerNOC agrees with the SCE that this application should be categorized as "ratesetting."[5] (See, Rule 1.3(e), Commission Rules of Practice and Procedure; Public Utilities Code §1701.1 (c)(3)). As to the need for an evidentiary hearing, in this early stage of review of SCE's application, EnerNOC believes it is premature to rule out the need for evidentiary hearings, especially given the factual nature of this application and the potential for disputes to arise with respect to material issues of fact. For this reason, and given the extension of time to file protests, EnerNOC proposes a schedule below that is based on SCE's proposed "Schedule

[3] SCE Testimony in support of A.14-11-016, at p. 8 (SCE (Cushnie)).
[4] Commission's Rules of Practice and Procedure, Rule 2.6(d).
[5] A.14-11-016, at p. 6..

with Evidentiary Hearings,"[6] with reasonably required modifications to allow sufficient time for the review of this application, discovery, and intervenor testimony.

With respect to the issues raised by the application, EnerNOC, again, continues to review this application, but, as of this date, has identified its issues of concern stated above and asks for those issues to be included within the scope of this application. EnerNOC also reserves the right to raise additional issues at the Prehearing Conference, depending on the outcome of its further review of the application.[7]

As noted above, EnerNOC believes it is most appropriate, given the fact-intensive nature of the application, that the Commission adopt a schedule based on the likely prospect of evidentiary hearings. Thus, EnerNOC, with reference to SCE's proposed "Schedule with Evidentiary Hearings,"[8] offers the following proposed schedule that has been revised to recognize the change in dates for protests and replies and allows for a reasonable time for effective party participation on the important issues raised by A.14-11-016. While not yet consolidated, EnerNOC notes that this schedule mirrors that proposed by EnerNOC in its Response to A.14-11-012 (SCE LCR RFOs Western LA Basin) filed today and that consolidation may be appropriate given the related questions of law and fact between these two applications.[9]

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[6] A.14-11-016, at p. 7.

[7] EnerNOC notes that SCE's application does list issues for this application, but they are largely a summary of its requested relief that the application, the subject RFO, and the LCR RFO contracts, all be approved in their entirety and be deemed reasonable and prudent, with their costs recoverable in rates, subject to the SCE's cost allocation plan. (A.14-11-016, at pp. 10-11.)

[8] A.14-11-016, at pp. 7-8.

[9] Commission Rules of Practice and Procedure, Rule 7.4

ENERNOC'S PROPOSED SCHEDULE

EVENT	DATE
Protests/Responses to Application	January 12, 2015
Replies to Protests/Responses	January 22, 2015
Prehearing Conference	February 5, 2015
Intervenor Testimony	March 5, 2015
Rebuttal Testimony	March 26, 2015
Hearings	April 13 - 16, 2015
Concurrent Opening Briefs	May 11, 2015
Concurrent Reply Briefs	May 27, 2015
Proposed Decision	August 18, 2015
Comments on Proposed Decision	September 7, 2015
Reply Comments on Proposed Decision	September 14, 2015
CPUC Business Meeting Agenda Date	October 5, 2015

V.
CONCLUSION

For the reasons stated above, EnerNOC submits its response, in part, to A.14-11-016, SCE' s application for application for approval of the results of its 2013 LCR RFOs for the Moorpark Sub-Area. EnerNOC respectfully requests its recommendations on the issues and schedule for this application be considered and included in any resulting Scoping Ruling for this application. EnerNOC looks forward to continued participation in this application.

Respectfully submitted:

January 12, 2015

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For EnerNOC, Inc.

EXHIBIT PE-26

California ISO Planning Standards

June 23, 2011

Table of Contents

I. Introduction

The California ISO (ISO) tariff provides for the establishment of planning guidelines and standards above those established by NERC and WECC to ensure the secure and reliable operation of the ISO controlled grid. The primary guiding principle of these Planning Standards is to develop consistent reliability standards for the ISO grid that will maintain or improve transmission system reliability to a level appropriate for the California system.

These ISO Planning Standards are not intended to duplicate the NERC and WECC reliability standards, but to complement them where it is in the best interests of the security and reliability of the ISO controlled grid. The ISO planning standards will be revised from time to time to ensure they are consistent with the current state of the electrical industry and in conformance with NERC Reliability Standards and WECC Regional Criteria. In particular, the ISO planning standards:

- Address specifics not covered in the NERC Reliability Standards and WECC Regional Criteria;
- Provide interpretations of the NERC Reliability Standards and WECC Regional Criteria specific to the ISO Grid;
- Identify whether specific criteria should be adopted that are more stringent than the NERC Reliability Standards and WECC Regional Criteria where it is in the best interest of ensuring the ISO controlled grid remains secure and reliable.

NERC Reliability Standards and WECC Regional Criteria:

The following links provide the minimum standards that ISO needs to follow in its planning process unless NERC or WECC formally grants an exemption or deference to the ISO. They are the NERC Transmission Planning (TPL) standards, other applicable NERC standards (i.e., NUC-001 Nuclear Plant Interface Requirements (NPIRs) for Diablo Canyon Power Plant and San Onofre Nuclear Generating Station), and the WECC Regional Criteria:

http://www.nerc.com/page.php?cid=2|20

http://www.wecc.biz/Standards/WECC%20Criteria/Forms/AllItems.aspx

Section II of this document provides additional details about the ISO Planning Standards. Guidelines are provided in subsequent sections to address certain ISO planning standards, such as the use of new Special Protection Systems, which are not specifically addressed at the regional level of NERC and WECC. Where appropriate, background information behind the development of these standards and references (web links) to subjects associated with reliable transmission planning and operation are provided.

II. ISO Planning Standards

The ISO Planning Standards are:

1. Applicability of NERC Reliability Standards to Low Voltage Facilities under ISO Operational Control

The ISO will apply NERC Transmission Planning (TPL) standards, the NUC-001 Nuclear Plant Interface Requirements (NPIRs) for Diablo Canyon Power Plant and San Onofre Nuclear Generating Station, and the approved WECC Regional Criteria to facilities with voltages levels less than 100 kV or otherwise not covered under the NERC Bulk Electric System definition that have been turned over to the ISO operational control.

2. Combined Line and Generator Outage Standard

A single transmission circuit outage with one generator already out of service and the system adjusted shall meet the performance requirements of the NERC TPL standards for single contingencies (TPL002). Supporting information is located within Section IV of this document.

3. Voltage Standard

Standardization of low and high voltage levels as well as voltage deviations across the TPL-001, TPL-002, and TPL-003 standards is required across all transmission elements in the ISO controlled grid. The low voltage and voltage deviation guideline applies only to load and generating buses within the ISO controlled grid (including generator auxiliary load) since they are impacted by the magnitude of low voltage and voltage deviations. The high voltage standard applies to all buses since unacceptable high voltages can damage station and transmission equipment. These voltage standards are shown in Table 1.

All buses within the ISO controlled grid that cannot meet the requirements specified in Table 1 will require further investigation. Exceptions to this voltage standard may be granted by the ISO based on documented evidence vetted through an open stakeholder process. The ISO will make public all exceptions through its website.

Table 1
(Voltages are relative to the nominal voltage of the system studied)

Voltage level	Normal Conditions (TPL-001)		Contingency Conditions (TPL-002 & TPL-003)		Voltage Deviation	
	Vmin (pu)	Vmax (pu)	Vmin (pu)	Vmax (pu)	TPL-002	TPL-003
≤ 200 kV	0.95	1.05	0.90	1.1	≤5%	≤10%
≥ 200 kV	0.95	1.05	0.90	1.1	≤5%	≤10%
≥ 500 kV	1.0	1.05	0.90	1.1	≤5%	≤10%

4. Specific Nuclear Unit Standards

The criteria pertaining to the Diablo Canyon Power Plant (DCPP) and San Onofre Nuclear Generating Station (SONGS), as specified in the NUC-001 Nuclear Plant Interface Requirements (NPIRs) for DCPP and SONGS, and Appendix E of the Transmission Control Agreement located on the ISO web site at: http://www.caiso.com/docs/09003a6080/25/a3/09003a608025a3bd.pdf

5. Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard

A single module of a combined cycle power plant is considered a single contingency (G-1) and shall meet the performance requirements of the NERC TPL standards for single contingencies (TPL002). Supporting information is located in Section V of this document. Furthermore a single transmission circuit outage with one combined cycle module already out of service and the system adjusted shall meet the performance requirements of the NERC TPL standards for single contingencies (TPL002) as established in item 1 above.

A re-categorization of any combined cycle facility that falls under this standard to a less stringent requirement is allowed if the operating performance of the combined cycle facility demonstrates a re-categorization is warranted. The ISO will assess re-categorization on a case by case based on the following:

a) Due to high historical outage rates in the first few years of operation no exceptions will be given for the first two years of operation of a new combined cycle module.
b) After two years, an exception can be given upon request if historical data proves that no outage of the combined cycle module was encountered since start-up.
c) After three years, an exception can be given upon request if historical data proves that outage frequency is less than once in three years.

The ISO may withdraw the re-categorization if the operating performance of the combined cycle facility demonstrates that the combined cycle module exceeds a failure rate of once in three year. The ISO will make public all exceptions through its website.

6. Planning for New Transmission versus Involuntary Load Interruption Standard

This standard sets out when it is necessary to upgrade the transmission system from a radial to a looped configuration or to eliminate load dropping otherwise permitted by WECC and NERC planning standards through transmission infrastructure improvements. It does not address all circumstances under which load dropping is permitted under NERC and WECC planning standards.

1. No single contingency (TPL002 and ISO standard [G-1] [L-1]) should result in loss of more than 250 MW of load. This includes consequential loss of load as well as load that may need to be dropped after the first contingency (during the system adjustment period) in order to position the electric system for reliable operation in anticipation of the next worst contingency.
2. All single substations of 100 MW or more should be served through a looped system with at least two transmission lines "closed in" during normal operation.
3. Existing radial loads with available back-tie(s) (drop and automatic or manual pick-up schemes) should have their back-up tie(s) sized at a minimum of 50% of the yearly peak load or to accommodate the load 80% of the hours in a year (based on actual load shape for the area), whichever is more constraining.
4. Upgrades to the system that are not required by the standards in 1, 2 and 3 above may be justified by eliminating or reducing load outage exposure, through a benefit to cost ratio (BCR) above 1.0 and/or where there are other extenuating circumstances.

   To better understand the potential impact of the updated "planning for new transmission versus involuntary load interruption" standard, this standard will be considered a guideline for the first year that it is in effect in order to get an inventory of stations and transmission elements not in compliance and a cost impact of bringing them into compliance.

III. ISO Planning Guidelines

The ISO Planning Guidelines include the following:

1. New Special Protection Systems

As stated in the NERC glossary, a Special Protection System (SPS) is "an automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition of faulted components to maintain system reliability." In the context of new projects, the possible action of an SPS would be to detect a transmission outage (either a single contingency or credible multiple contingencies) or an overloaded transmission facility and then curtail generation output and/or load in order to avoid potentially overloading facilities or prevent the situation of not meeting other system performance criteria. A SPS can also have different functions such as executing plant generation reduction requested by other SPS; detecting unit outages and transmitting commands to other locations for specific action to be taken; forced excitation pulsing; capacitor and reactor switching; out-of-step tripping; and load dropping among other things.

The primary reasons why SPS might be selected over building new transmission facilities are that SPS can normally be implemented much more quickly and at a much lower cost than constructing new infrastructure. In addition, SPS can increase the utilization of the existing transmission facilities, make better use of scarce transmission resources and maintain system reliability. Due to these advantages, SPS is a commonly considered alternative to building new infrastructure in an effort to keep costs down when integrating new generation into the grid and/or addressing reliability concerns under multiple contingency conditions. While SPSs have substantial advantages, they have disadvantages as well. With the increased transmission system utilization that comes with application of SPS, there can be increased exposure to not meeting system performance criteria if the SPS fails or inadvertently operates. Transmission outages can become more difficult to schedule due to increased flows across a larger portion of the year; and/or the system can become more difficult to operate because of the independent nature of the SPS. If there are a large number of SPSs, it may become difficult to assess the interdependency of these various schemes on system reliability. These reliability concerns necessarily dictate that guidelines be established to ensure that performance of all SPSs are consistent across the ISO controlled grid. It is the intent of these guidelines to allow the use of SPSs to maximize the capability of existing transmission facilities while maintaining system reliability and optimizing operability of the ISO controlled grid. Needless to say, with the large number of generator interconnections that are occurring on the ISO controlled grid, the need for these guidelines has become more critical.

It needs to be emphasized that these are guidelines rather than standards. In general, these guidelines are intended to be applied with more flexibility for low exposure outages (e.g., double line outages, bus outages, etc.) than for high exposure outages (e.g., single contingencies). This is to emphasize that best engineering practice and judgement will need to be exercised by system planners and operators in determining when the application of SPS will be acceptable. It is recognized that it is not possible or desirable to have strict standards for the acceptability of the use of SPS in all potential applications.

ISO SPS1

The overall reliability of the system should not be degraded after the combined addition of the SPS.

ISO SPS2

The SPS needs to be highly reliable. Normally, SPS failure will need to be determined to be non-credible. In situations where the design of the SPS requires WECC approval, the WECC Remedial Action Scheme Design Guide will be followed.

ISO SPS3

The total net amount of generation tripped by a SPS for a single contingency cannot exceed the ISO's largest single generation contingency (currently one Diablo Canyon unit at 1150 MW). The total net amount of generation tripped by a SPS for a double contingency cannot exceed 1400 MW. This amount is related to the minimum amount of spinning reserves that the ISO has historically been required to carry. The quantities of generation specified in this standard represent the current upper limits for generation tripping. These quantities will be reviewed periodically and revised as needed. In addition, the actual amount of generation that can be tripped is project specific and may depend on specific system performance issues to be addressed. Therefore, the amount of generation that can be tripped for a specific project may be lower than the amounts provided in this guide. The net amount of generation is the gross plant output less the plant's and other auxiliary load tripped by the same SPS.

ISO SPS4

For SPSs, the following consequences are unacceptable should the SPS fail to operate correctly:

A) Cascading outages beyond the outage of the facility that the SPS is intended to protect: For example, if a SPS were to fail to operate as designed for a single contingency and the transmission line that the SPS was intended to protect were to trip on overload protection, then the subsequent loss of additional facilities due to overloads or system stability would not be an acceptable consequence.

B) Voltage instability, transient instability, or small signal instability: While these are rare concerns associated with the addition of new generation, the consequences can be so severe that they are deemed to be unacceptable results following SPS failure.

ISO SPS5

Close coordination of SPS is required to eliminate cascading events. All SPS in a local area (such as SDG&E, Fresno, etc.) and grid-wide need to be evaluated as a whole and studied as such.

ISO SPS6

The SPS must be simple and manageable. As a general guideline:

A) There should be no more than 6 local contingencies (single or credible double contingencies) that would trigger the operation of a SPS.

B) The SPS should not be monitoring more than 4 system elements or variables. A variable can be a combination of related elements, such as a path flow, if it is used as a single variable in the logic equation. Exceptions include:

    i. The number of elements or variables being monitored may be increased if it results in the elimination of unnecessary actions, for example: generation tripping, line sectionalizing or load shedding.

    ii. If the new SPS is part of an existing SPS that is triggered by more than 4 local contingencies or that monitors more than 4 system elements or variables, then the new generation cannot materially increase the complexity of the existing SPS scheme. However, additions to an existing SPS using a modular design should be considered as preferable to the addition of a new SPS that deals with the same contingencies covered by an existing SPS.

C) Generally, the SPS should only monitor facilities that are connected to the plant or to the first point of interconnection with the grid. Monitoring remote facilities may add substantial complexity to system operation and should be avoided.

D) An SPS should not require real-time operator actions to arm or disarm the SPS or change its set points.

<u>ISO SPS7</u>
If the SPS is designed for new generation interconnection, the SPS may not include the involuntary interruption of load. Voluntary interruption of load paid for by the generator is acceptable. The exception is that the new generator can be added to an existing SPS that includes involuntary load tripping. However, the amount of involuntary load tripped by the combined SPS may not be increased as a result of the addition of the generator.

<u>ISO SPS8</u>
Action of the SPS shall limit the post-disturbance loadings and voltages on the system to be within all applicable ratings and shall ultimately bring the system to within the long-term (4 hour or longer) emergency ratings of the transmission equipment. For example, the operation of SPS may result in a transmission line initially being loaded at its one-hour rating. The SPS could then automatically trip or run-back additional generation (or trip load if not already addressed under ISO SPS7 above) to bring the line loading within the line's four-hour or longer rating. This is intended to minimize real-time operator intervention.

<u>ISO SPS9</u>
The SPS needs to be agreed upon by the ISO and may need to be approved by the WECC Remedial Action Scheme Reliability Task Force.

<u>ISO SPS10</u>
The ISO, in coordination with affected parties, may relax SPS requirements as a temporary bridge to system reinforcements. Normally this bridging period would be limited to the time it takes to implement a specified alternative solution. An example of a relaxation of SPS requirement would be to allow 8 initiating events rather than limiting the SPS to 6 initiating events until the identified system reinforcements are placed into service.

<u>ISO SPS11</u>
The ISO will consider the expected frequency of operation in its review of SPS proposals.

<u>ISO SPS12</u>
The actual performance of existing and new SPS schemes will be documented by the transmission owners and periodically reviewed by the ISO and other interested parties so that poorly performing schemes may be identified and revised.

ISO SPS13
All SPS schemes will be documented by the owner of the transmission system where the SPS exists. The generation owner, the transmission owner, and the ISO shall retain copies of this documentation.

ISO SPS14
To ensure that the ISO's transmission planning process consistently reflects the utilization of SPS in its annual plan, the ISO will maintain documentation of all SPS utilized to meet its reliability obligations under the NERC reliability standards, WECC regional criteria, and ISO planning standards.

ISO SPS15
The transmission owner in whose territory the SPS is installed will, in coordination with affected parties, be responsible for designing, installing, testing, documenting, and maintaining the SPS.

ISO SPS16 Generally, the SPS should trip load and/or resources that have the highest effectiveness factors to the constraints that need mitigation such that the magnitude of load and/or resources to be tripped is minimized. As a matter of principle, voluntary load tripping and other pre-determined mitigations should be implemented before involuntary load tripping is utilized.

ISO SPS17
Telemetry from the SPS (e.g., SPS status, overload status, etc.) to both the Transmission Owner and the ISO is required unless otherwise deemed unnecessary by the ISO. Specific telemetry requirements will be determined by the Transmission Owner and the ISO on a project specific basis.

IV. Combined Line and Generator Unit Outage Standards Supporting Information

Combined Line and Generator Outage Standard - A single transmission circuit outage with one generator already out of service and the system adjusted shall meet the performance requirements of the NERC TPL standards for single contingencies (TPL002).

The ISO Planning Standards require that system performance for an over-lapping outage of a generator unit (G-1) and transmission line (L-1) must meet the same system performance level defined for the NERC standard TPL-002. The ISO recognizes that this planning standard is more stringent than allowed by NERC, but it is considered appropriate for assessing the reliability of the ISO's controlled grid as it remains consistent with the standard utilized by the PTOs prior to creation of the ISO.

V. Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard Supporting Information

Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard - A single module of a combined cycle power plant is considered a single (G-1) contingency and shall meet the performance requirements of the NERC TPL standards for single contingencies (TPL002).

The purpose of this standard is to require that an outage of any turbine element of a combustion turbine be considered as a single outage of the entire plant and therefore must meet the same performance level as the NERC TPL standard TPL-002.

The ISO has determined that, a combined cycle module should be treated as a single contingency. In making this determination, the ISO reviewed the actual operating experience to date with similar (but not identical) combined cycle units currently in operation in California. The ISOs determination is based in large part on the performance history of new combined cycle units and experience to date with these units. The number of combined cycle facility forced outages that have taken place does not support a double contingency categorization for combined cycle module units in general. It should be noted that all of the combined cycle units that are online today are treated as single contingencies.

Immediately after the first few combined cycle modules became operational, the ISO undertook a review of their performance. In defining the appropriate categorization for combined cycle modules, the ISO reviewed the forced outage history for the following three combined cycle facilities in California: Los Medanos Energy Center (Los Medanos), Delta Energy Center (Delta), and Sutter Energy Center (Sutter)[1]. Los Medanos and Sutter have been in service since the summer of 2001, Delta has only been operational since early summer 2002.

Table 2 below sets forth the facility forced outages for each of these facilities after they went into operation (i.e. forced outages [2]that resulted in an output of zero MWs.) The table demonstrates that facility forced outages have significantly exceeded once every 3 to 30 years. Moreover, the ISO considers that the level of facility forced outages is significantly above the once every 3 to 30 years even accounting for the fact that new combined cycle facilities tend to be less reliable during start-up periods and during the initial weeks of operation. For example, four of the forced outages that caused all the

[1] Los Medanos and Sutter have two combustion turbines (CT's) and one steam turbine (ST) each in a 2x1 configuration. Delta has three combustion turbines (CT's) and one steam turbine (ST) in a 3x1 configuration. All three are owned by the Calpine Corporation.

[2] Only forced outages due to failure at the power plant itself are reported, forced outages due to failure on the transmission system/switchyard are excluded. The fact that a facility experienced a forced outage on a particular day is public information. In fact, information on unavailable generating units has been posted daily on the ISO website since January 1, 2001. However, the ISO treats information regarding the cause of an outage as confidential information.

three units at Los Medanos to go off-line took place more than nine months after the facility went into operation.

Facility	Date	# units lost
Sutter[3]	08/17/01	No visibility
Sutter	10/08/01	1 CT
Sutter	12/29/01	All 3
Sutter	04/15/02	1 CT + ST
Sutter	05/28/02	1 CT
Sutter	09/06/02	All 3
Los Medanos[4]	10/04/01	All 3
Los Medanos	06/05/02	All 3
Los Medanos	06/17/02	All 3
Los Medanos	06/23/02	1CT+ST
Los Medanos	07/19/02	All 3
Los Medanos	07/23/02	1CT+ST
Los Medanos	09/12/02	All 3
Delta[5]	06/23/02	All 4
Delta	06/29/02	2 CT's + ST
Delta	08/07/02	2 CT's + ST

Table 2: Forced outages that have resulted in 0 MW output from Sutter, Los Medanos and Delta after they became operational

The ISO realizes that this data is very limited. Nevertheless, the data adequately justifies the current classification of each module of these three power plants as a single contingency.

VI. Background behind Planning for New Transmission versus Involuntary Load Interruption Standard

For practical and economic reasons, all electric transmission systems are planned to allow for some involuntary loss of firm load under certain contingency conditions. For some systems, such a loss of load may require several contingencies to occur while for other systems, loss of load may occur in the event of a specific single contingency. Historically, a wide variation among the PTOs has existed predominantly due to slightly differing planning and design philosophies. This standard is intended to provide a consistent framework upon which involuntary load interruption decisions can be made by the ISO when planning infrastructure needs for the ISO controlled grid.

[3] Data for Sutter is recorded from 07/03/01 to 08/10/02
[4] Data for Los Medanos is recorded from 08/23/01 to 08/10/02
[5] Data for Delta is recorded from 06/17/02 to 08/10/02

The overarching requirement is that implementation of these standards should not result in lower levels of reliability to end-use customers than existed prior to restructuring. As such, the following is required:

1. No single contingency (TPL002 and ISO standard [G-1] [L-1]) may result in loss of more than 250 MW of load. This includes consequential loss of load as well as load that may need to be dropped after the first contingency (during the system adjustment period) in order to protect for the next worst single contingency.

   This standard is intended to coordinate ISO planning standards with the WECC requirement that all transmission outages with at least 300 MW or more be directly reported to WECC. It is the ISO's intent that no single contingency (TPL002 and ISO standard [G-1] [L-1]) should trigger loss of 300 MW or more of load. The 250 MW level is chosen in order to allow for differences between the load forecast and actual real time load that can be higher in some instances than the forecast and to also allow time for transmission projects to become operational since some require 5-6 years of planning and permitting with inherent delays. It is also ISO's intent to put a cap on the footnote to the NERC TPL-002 that may allow radial and/or non-consequential loss of load for single contingencies.

2. All single substations of 100 MW or more should be served through a looped system with at least two transmission lines "closed in" during normal operation.

   This standard is intended to bring consistency between the PTOs' substation designs. It is not the ISO's intention to disallow substations with load below 100 MW from having looped connections; however it is ISO's intention that all substations with peak load above 100 MW must be connected through a looped configuration to the grid.

3. Existing radial loads with available back-tie(s) (drop and automatic or manual pick-up schemes) should have their back-up tie(s) sized at a minimum of 50% of the yearly peak load or to accommodate the load 80% of the hours in a year (based on actual load shape for the area), whichever is more stringent.

   This standard is intended to insure that the system is maintained at the level that existed prior to restructuring. It is obvious that as load grows, existing back-ties for radial loads (or remaining feed after a single contingency for looped substations) may not be able to pick up the entire load; therefore the reliability to customers connected to this system may deteriorate over time. It is the ISO's intention to establish a minimum level of back-up tie capability that needs to be maintained.

4. Upgrades to the system that are not required by the standards in 1, 2 and 3 above may be justified by eliminating or reducing load outage exposure through a benefit to cost ratio (BCR) above 1.0 and/or where there are other extenuating circumstances.

It is ISO's intention to allow the build-up of transmission projects that are proven to have a positive benefit to ratepayers by reducing load drop exposure.

Information Required for BCR calculation: For each of the outages that required involuntary interruption of load, the following should be estimated:

- The maximum amount of load that would need to be interrupted.
- The duration of the interruption.
- The annual energy that would not be served or delivered.
- The number of interruptions per year.
- The time of occurrence of the interruption (e.g., week day summer afternoon).
- The number of customers that would be interrupted.
- The composition of the load (i.e., the percent residential, commercial, industrial, and agricultural).
- Value of service or performance-based ratemaking assumptions concerning the dollar impact of a load interruption.

The above information will be documented in the ISO Transmission Plan for areas where additional transmission reinforcement is needed or justified through benefit to cost ratio determination.

VII. Interpretations of terms from NERC Reliability Standard and WECC Regional Criteria

Listed below are several ISO interpretations of the terms that are used in the NERC standards that are not already addressed by NERC.

Combined Cycle Power Plant Module: A **combined cycle** is an assembly of heat engines that work in tandem off the same source of heat, converting it into mechanical energy, which in turn usually drives electrical generators. In a combined cycle power plant (CCPP), or combined cycle gas turbine (CCGT) plant, one or more gas turbine generator(s) generates electricity and heat in the exhaust is used to make steam, which in turn drives a steam turbine to generate additional electricity.

Entity Responsible for the Reliability of the Interconnected System Performance: In the operation of the grid, the ISO has primary responsibility for reliability. In the planning of the grid, reliability is a joint responsibility between the PTO and the ISO subject to appropriate coordination and review with the relevant local, state, regional and federal regulatory authorities.

Entity Required to Develop Load Models: The PTOs, in coordination with the utility distribution companies (UDCs) and others, develop load models.

Entity Required to Develop Load Forecast: The California Energy Commission (CEC) has the main responsibility for providing load forecast. If load forecast is not provided by the CEC or is not detailed and/or specific enough for a certain study then the ISO, at its sole discretion, may use load forecasts developed by the PTOs in coordination with the UDCs and others.

Projected Customer Demands: 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. 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.

Planned or Controlled Interruption: Load interruptions can be either automatic or through operator action as long as the specific actions that need to be taken, including the magnitude of load interrupted, are identified and corresponding operating procedures are in place when required.

Time Allowed for Manual Readjustment: This is the amount of time required for the operator to take all actions necessary to prepare the system for the next contingency. This time should be less than 30 minutes.

EXHIBIT PE-27

Rulemaking No.:	12-03-014
Exhibit No.:	SCE-1
Witnesses:	Garry Chinn Colin Cushnie Mark Nelson Jonathan Rumble Carl Silsbee

SOUTHERN CALIFORNIA EDISON®

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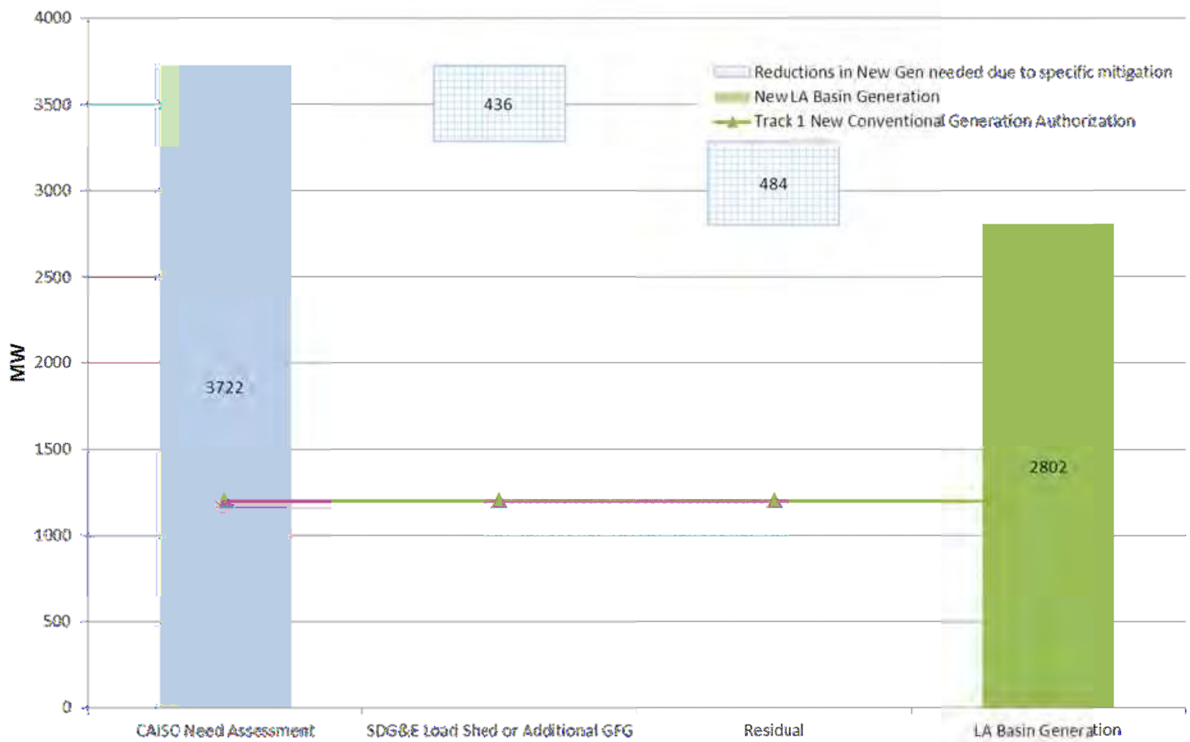
TRACK 4 TESTIMONY OF SOUTHERN CALIFORNIA EDISON COMPANY

Before the
Public Utilities Commission of the State of California

Rosemead, California
August 26, 2013

Figure II-1
Need In the LA Basin



B. <u>SCE's Recommendations For Use Of Transmission Projects To Meet Local Reliability Needs</u>

SCE investigated two transmission scenarios, the Mesa Loop-In and a regional transmission project that strengthens the interconnection between SCE and SDG&E, as described in Chapter III. Figure II-2 below shows the results of certain SCE scenarios only. Figure II-2 shows that the Mesa Loop-In further reduces the need for LCR resources in the LA Basin by 1,196 MW.[8] While the Mesa Loop-In reduces the need for LA Basin generation, it does not

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[8] While the Mesa Loop-In will reduce the need for generation in the LA Basin, it assumes there are 503 MW of sufficient generation out of the LA Basin to meet load. For modeling purposes only, additional capacity was

Continued on the next page

sections and breakers) violates system performance requirements specified by the NERC Reliability Standards.[16]

The United States Congress created an electric reliability organization (ERO) through the Energy Policy Act of 2005. The Federal Energy Regulatory Commission (FERC) certified NERC as the ERO on July 20, 2006. NERC develops, implements, and enforces mandatory reliability standards for the bulk power system. NERC performs its duties in accordance with Section 215 of the Federal Power Act. The statute requires users, owners and operators of the bulk power system in the United States to be subject to FERC approved NERC Reliability Standards.

These standards require the simulation of a range of potential conditions from no contingencies (Category A) to extreme events (Category D). The two intermediate categories of contingencies, Category B, events resulting in the loss of a single element and Category C, event(s) resulting in the loss of two or more elements constitute the majority of contingencies examined in SCE's studies. An example of a Category B contingency is the fault and loss of one transformer bank. An example of a Category C contingency is the fault and simultaneous loss of two transmission lines that share a common tower.

Attachment 1 is Table 1 from NERC Reliability Standard TPL-001-3 which provides a complete description of Category A through D contingencies and the associated system performance requirements. Table 1 is common to transmission planning standards TPL-001-3, TPL-002-2b, TPL-003-2b, and TPL-004-2a. These NERC Transmission Planning (TPL) Reliability Standards require the system to be stable and both thermal and voltage limits to be within facility

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[16] NERC transmission planning Reliability Standards include TPL-001-3 (Category A), TPL-002-2b (Category B), TPL-003-2b (Category C), and TPL-004-2a (Category D).

ratings for Categories A through C. 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. SCE's power flow studies examined Category A through D conditions for facilities in SCE and SDGE's service areas.

b) <u>SCE's Studies Look For Thermal Overloading and Voltage Violations During These Contingencies</u>

SCE's studies identify both thermal overload and voltage violations for Category A through D conditions. The studies look for power flows in excess of normal (Category A) and emergency (Categories B through D) thermal ratings of transmission facilities. SCE establishes the thermal ratings of transmission facilities as the owner of these facilities to prevent damage to equipment and assure safe clearances are maintained in accordance with General Order No. 95. The studies also look for voltages at substations outside of specific bandwidths and percentage deviations in excess of thresholds established by the CAISO as provided in Table III-2 below[17]. Maintaining voltages at substations prevents voltage collapse events in which voltages in a portion of the electric system decrease catastrophically causing a blackout. The CAISO established these voltage limits via an open stakeholder process in 2011. Based on the identified thermal overloads and voltage violations, SCE develops mitigation options to improve system performance.

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[17] "California ISO Planning Standards", June 23, 2011, Section II.3., page 4

EXHIBIT PE-28

A. Introduction

1. **Title:** System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

2. **Number:** TPL-004-2

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability**:

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote `b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after approval by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. All other requirements remain in effect per previous approvals. The existing Footnote `b' remains in effect until the revised Footnote `b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority' s and Transmission Planner' s assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

B. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-2_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-2_R1.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

D. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	February 17, 2011	Approved by the Board of Trustees; revised footnote `b' pursuant to FERC Order RM06-16-009.	Revised (Project 2010-11)
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote b in accordance with the directives of Order Nos. 762 and 693.	
2	February 7, 2013	Adopted by NERC Board of Trustees. Revised footnote `b'.	

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process is to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner' s planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. For purposes of this footnote, the following are not counted as Firm Demand: (1) Demand directly served by the Elements removed from service as a result of the Contingency, and (2) Interruptible Demand or Demand-Side Management Load. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote `b' exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

c) 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.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Firm Demand interruption under footnote `b' is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote `b' is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Firm Demand interruption under footnote `b'
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Firm Demand interruption under footnote `b' (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder' s satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote `b' utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Firm Demand interruption under footnote `b' which must include the following:

1. Conditions under which Firm Demand interruption under footnote `b' would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Firm Demand MW to be interrupted with:
    a. The estimated number and type of customers affected

   b. An explanation of the effect of the use of Firm Demand interruption under footnote `b' on the health, safety, and welfare of the community
3. Estimated frequency of Firm Demand interruption under footnote `b' based on historical performance
4. Expected duration of Firm Demand interruption under footnote `b' based on historical performance
5. Future plans to alleviate the need for Firm Demand interruption under footnote `b'
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote `b'
7. Alternatives to Firm Demand interruption considered and the rationale for not selecting those alternatives under footnote `b'
8. Assessment of potential overlapping uses of footnote `b' including overlaps with adjacent Transmission Planners and Planning Coordinators

<u>III. Instances for which Regulatory Review of Interruptions of Firm Demand under Footnote `b' is Required</u>

Before a Firm Demand interruption under footnote `b' is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Firm Demand interruption under footnote `b' if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Firm Demand interruptions under footnote `b', or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Firm Demand interruption under footnote `b' is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Firm Demand interruption under footnote `b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote `b' for Firm Demand interruption.

EXHIBIT PE-29

Southern California Edison
LCR RFO Moorpark A.14-11-016

DATA REQUEST SET A.14-11-016 LCR RFO-CBD-SCE-002

To: CBD
Prepared by: Daniel Donaldson
Title: Power System Planner
Dated: 04/01/2015

Question 01:

Reference

A.14-11-016 Testimony of SCE, page 5

"All substations in the Moorpark area have the same Locational Effectiveness Factors ("LEFs") with respect to the critical contingency, which is the loss of the three Moorpark-Pardee lines.10 10 CAISO 2011-2012 Transmission Plan at 244."

2011-2012 CAISO Transmission Plan, page 243

"The most critical contingency for the Moorpark sub-area is the N-1 outage followed by N-2 outage-loss of Pardee-Moorpark #1 230 kV line and Pardee-Moorpark #2 and #3 230 kV lines. This would result in a voltage collapse. To mitigate this voltage collapse, about 430 MW of OTC units are required as part of the LCR for this sub-area."

Question

Does SCE have an authorized SPS (load shed) protocol for this contingency, and if so, what is the amount of authorized load shedding in MW?

Response to Question 01:

SCE does not have an authorized SPS (load shed) protocol for this contingency.

EXHIBIT PE-30

can be approved on reliability grounds. If not, an economic assessment of the project may be conducted to see whether it can be approved based on its economic value.

The CAISO used the following applicable reliability standards for the CSRTP-2006 process:

1. NERC/WSCC Planning Standards - For purposes of capacity planning for a specific area, G-1/N-1 reliability criterion requires that there be sufficient in-area resources and transmission import capability to serve the full adverse peak demand forecast during the worst G-1/N-1 event.
2. Specific Nuclear Unit Standards - The criteria pertaining to the Diablo Canyon and San Onofre Nuclear Power Plants, as specified in Appendix E of the Transmission Control Agreement.
3. Combined Line and Generator Outage Standard - A single transmission circuit outage with one generator already out of service and the system adjusted shall meet the performance requirements of the NERC Planning Standards for Category B contingencies.
4. New Transmission versus Involuntary Load Interruption Standard
   - Involuntary load interruptions are not an acceptable consequence in planning for CAISO Planning Standard Category B disturbances (either single contingencies or the combined contingency of a single generator and a single transmission line), unless the CAISO Board decides that the capital project alternative is clearly not cost effective (after considering all the costs and benefits). In any case, planned load interruptions for Category B disturbances are to be limited to radial and local network customers as specified in the NERC Planning Standards.
   - Involuntary load interruptions are an acceptable consequence in planning for CAISO Planning Standard Category C and D disturbances (multiple contingencies with the exception of the combined outage of a single generator and a single transmission line), unless the CAISO Board decides that the capital project alternative is clearly cost effective (after considering all the costs and benefits).
   - In cases where the application of Standards 4A and 4B would result in the elimination of a project or relaxation of standards that would have been built under past planning practices, these cases will be presented to the CAISO Board for a determination as to whether or not the projects should be constructed.
5. San Francisco Greater Bay Area Generation Outage Standard if needed for conducting Grid Planning studies for the San Francisco Greater Bay Area.

Standards 2-5 provide specifics not covered in the NERC/WSCC Planning Standards.