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State of California

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Conservation and Development Commission

In the Matter of: Application for Certification for the PUENTE POWER PROJECT	Docket No. 15-AFC-01 APPLICANT'S REBUTTAL TESTIMONY

Applicant hereby submits its Rebuttal Testimony in connection with the upcoming evidentiary hearings for the Puente Power Project (Project) per the Hearing Officer Memo re: Updated Proceeding Dates and Deadlines and Committee Requests for Information, issued on January 4, 2017 (TN #: 215157). Applicant's Rebuttal Testimony is comprised of a series of rebuttal declarations made by subject matter experts who have conducted analysis related to various aspects of the Project. Table A lists Applicant's Rebuttal Testimony Declarants, the company they are employed by, and the topic area or areas covered by their declaration.

Table A

Applicant's Rebuttal Testimony Declarants

No.	Declarant	Company	Topic Area(s)
1.	Thomas Di Ciolli	NRG	Impact of Identified Storm Events on Mandalay Generating Station Property
2.	Dawn Gleiter	NRG	Site Availability
3.	Mark Hale	AECOM	Alternative Sites – Archeological Resources
4.	Jeremy Hollins	AECOM	Alternative Sites – Historical Resources
5.	Julie Love	AECOM	Wetland Designation
6.	Julie Love	AECOM	Alternative Sites – Biological Resources
7.	Julie Love	AECOM	Response to Statements of Lawrence E. Hunt and Ilene Anderson regarding Biological Resources
8.	Phil Mineart	AECOM	Water Resources
9.	Tim Murphy	AECOM	Land Use
10.	George Piantka	NRG	Project Alternatives
11.	Gary Rubenstein	Sierra Research	Environmental Justice
12.	Gary Rubenstein	Sierra Research	Alternative Sites – Aviation Hazards
13.	Gary Rubenstein	Sierra Research	Alternative Sites – Environmental Justice
14.	Gary Rubenstein	Sierra Research	Response to CDB Witness Bill Powers
15.	Brian Theaker	NRG	Transmission Interconnection for Alternative Sites
16.	Brian Theaker and Sean Beatty	NRG	Response to Opening Testimony of CBD Witness Bill Powers and Opening Testimony of City of Oxnard Witness Jim Caldwell
17.	Tricia Winterbauer	AECOM	Contaminated Soils

DATED: January 24, 2017

Respectfully submitted,

/s/ Michael J. Carroll

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Michael J. Carroll
LATHAM & WATKINS LLP
Counsel to Applicant

1. Thomas Di Ciolli

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In the Matter of: Application for Certification for the PUENTE POWER PROJECT	Docket No. 15-AFC-01 DECLARATION OF THOMAS DI CIOLLI REGARDING IMPACTS OF IDENTIFIED STORM EVENTS ON MANDALAY GENERATING STATION PROPERTY

I, Thomas Di Ciolli, declare as follows:

1. I am employed by NRG Energy, Inc., and am duly authorized to make this declaration.

2. I am the Plant Manager for the Mandalay Generating Station ("MGS") located in Oxnard, California. I have held the position of Plant Manager since 2005. Prior to that time, I held the position of Major Maintenance Manager from 2001 through 2005. In my role as Plant Manager, I am responsible for all aspects of the operation and maintenance of the MGS, and am made aware of any conditions that might materially affect the operation of the MGS.

3. Plant personnel conduct daily inspections of the MGS property and adjacent areas for the purpose of identifying any conditions that might materially affect operation of the MGS. Areas inspected include the ocean discharge outfall and the surrounding dune and beach area west of the MGS property. Any notable conditions that are identified, including any conditions in the dune and beach area brought about by storm events, are recorded in a Daily Operating Log.

4. Routine daily inspections of MGS property and adjacent areas, including the ocean discharge outfall and the surrounding dune and beach area west of the MGS property, were performed on December 11, 2015 and December 16, 2015. There were no observations of any material beach or dune erosion or other effects of the storm events that occurred on those dates.

5. Routine daily operations' inspections of MGS property and adjacent areas, including the ocean discharge outfall and the surrounding dune and beach area west of the MGS property, were performed during 'King Tide' events which occurred on December 22, 23, and 24, 2015. There were no observations of any material beach or dune erosion or other effects of the storm event.

6. Attached to this declaration as Attachment A, and incorporated herein by reference, are the Daily Operating Logs for December 11, 2015, December 16, 2015 and December 22, 23, and 24, 2015 prepared contemporaneously with the inspection of the facility on that day. There is no indication in the attached Daily Operating Logs of any material adverse effect associated with the storm events that occurred on those dates.

7. Except where stated on information and belief, the facts set forth herein, and in the attachments hereto, are true of my own personal knowledge, and the opinions set forth herein and in the attachments hereto are true and correct articulations of my opinions. If called as a witness I could and would testify competently to the facts and opinions set forth herein and in the attachments hereto.

8. I hereby sponsor this declaration into evidence in these proceedings as Applicant's Exhibit No. 1121.

Executed on January 24, 2017, at Oxnard, California

I declare under penalty of perjury of the laws of the State of California that the foregoing is true and correct.

Thomas Di Ciolli

2. Dawn Gleiter

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In the Matter of: Application for Certification for the PUENTE POWER PROJECT	Docket No. 15-AFC-01 DECLARATION OF DAWN GLEITER REGARDING PROJECT ALTERNATIVES

I, Dawn Gleiter, declare as follows:

1. I am employed by NRG Energy, Inc. as Director of Sustainable Development, and I am the Project Director for the Puente Power Project (Project). I am duly authorized to make this declaration.

2. I have reviewed the statement of John Woodford Hansen filed on January 18, 2017 by the City of Oxnard (TN #215423) in which Mr. Hansen states that Arcturus Warehouse, LLC ("Arcturus"), the owner of the property located at 5980 and 6000 Arcturus Avenue, Oxnard (APN's 231-0-093-135 and 231-0-093-155) (the "Property"), which is identified in CEC Staff's Final Staff Assessment, Part 1, Section 4.2 Alternatives as the "Ormond Beach Area Off-Site Alternative," is open to the sale of all or part of the Property. Mr. Hansen further asserts that during Arcturus's negotiations to acquire the subject property from the prior owner, RET1A USA, LLC, ("RET1A"), it did not receive any indication from RET1A that NRG or its representative or agent had made any inquiry regarding the acquisition of the Property.

3. Mr. Hansen's statement does not reflect an understanding of the substantial lead time for development of a project such as Puente, and the need to demonstrate control over the proposed site relatively early in the process.

4. Southern California Edison (SCE) issued the 2013 Local Capacity Requirements Request for Offers for the Moorpark Sub-Area (Track 1) (the "RFO") in September 2013. NRG Energy, Inc., as predecessor in interest to the Applicant, submitted its response to the RFO on December 16, 2013. One of the prerequisites to submitting a response to the RFO was that the responding party demonstrate control over the site on which the proposed project was to be located. All gas fired generation and combined heat and power proposed projects in this solicitation were required to demonstrate site control or they would have been dropped from further consideration in the solicitation.

5. In January of 2014, the Applicant was notified that the project proposal had been shortlisted and began negotiations with SCE. In November 2014, the Applicant was awarded a contract for the development of the Project, pursuant to which the Applicant entered into a 20-year Resource Adequacy Purchase Agreement (RAPA) with SCE on November 3, 2014.

6. The Applicant would have never been shortlisted without an adequate demonstration of control over the site. Thus, in order for the Ormond Beach Area Off-Site Alternative to have been a feasible alternative site for development of the Project, Applicant would have required site control prior to December 16, 2013. Applicant could not have satisfied the requirements of either the RFO or subsequently entered into the RAPA by entering into negotiations with either Arcturus Warehouse or RET1A since neither of those entities owned the property at a time when purchase would have been feasible or timely.

7. According to the Ventura County Assessor's website (http://prop-tax.countyofventura.org/listing.aspx), RET1A acquired the Property from Cooks Composites & Polymers Co. ("Cooks") on October 2, 2015, and Cooks owned the Property from May 11, 2011 until its sale to RET1A on October 2, 2015.

8. On July 11, 2013, NRG Energy, Inc., through its agent CBRE, executed a

bond fide Letter of Intent regarding the purchase of the Property from Cooks, a copy of which is attached to this declaration as Attachment A. This Letter of Intent was never executed by Cooks, and as a result, the transaction contemplated therein never occurred.

9. Except where stated on information and belief, the facts set forth herein and in the other Applicant's Exhibits identified herein are true of my own personal knowledge, and the opinions set forth herein and in the other Applicant's Exhibits identified herein are true and correct articulations of my opinions. If called as a witness, I could and would testify competently to the facts and opinions set forth herein and in the other Applicant's Exhibits identified herein.

10. I hereby sponsor this declaration into evidence in these proceedings as Applicant's Exhibit No. 1119.

Executed on January 24, 2017, at San Francisco.

I declare under penalty of perjury of the laws of the State of California that the foregoing is true and correct.

Dawn Gleiter

ATTACHMENT A

COMMERCIAL REAL ESTATE SERVICES

CBRE

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July 11, 2013

Mr. Greg Geary
Cook Composites
Via email Greg.Geary@ccpcompositesus.com

RE: Assessor's Parcel Numbers
231-0-093-135; 155
Oxnard, California

Dear Greg:

My client, NRG Energy of this letter is to provide an outline of the basic terms and conditions upon which NRG Energy, Inc. or nominee ("Buyer") would be willing to buy the above-referenced property from CCP Composites USA ("Seller"). This letter is solely a Letter of Intent and is non-binding and any obligation on the part of the Seller or the Buyer will be subject to the execution of a definitive purchase agreement (the "Purchase Agreement"). The Purchase Agreement will contain the following essential business provisions.

Subject Property:
Two parcels of land totaling approximately 13.64 acres located in Oxnard, California, zoned M2PD. Exact legal descriptions to be provided in Escrow.

Buyer:
NRG Energy, Inc. or nominee.

Price and Terms:

REDACTED

Deposit:
Upon the mutual execution of a Purchase Agreement, REDACTED (the "Initial Deposit") shall be deposited into Escrow, with interest to accrue to the benefit of Buyer. Said Initial Deposit shall be fully refundable to Buyer in the event that Buyer does not approve contingencies as called out in the Inspection/Feasibility section. All funds deposited by Buyer into escrow shall be applicable to the purchase price.

Inspection/Feasibility Period:
Buyer shall have a period of 180 days from the mutual execution of a Purchase Contract to conduct its Inspection/Feasibility evaluation. If the Buyer is not satisfied with the Property during the Inspection/Feasibility Period for any reason, Buyer may elect to cancel escrow, the Initial Deposit and interest shall be returned to Buyer and the Escrow will be cancelled.

Seller grants access to Buyer to conduct soils studies and Buyer will hold Seller harmless from any liens or encumbrances generated by Buyer. Seller shall retain the right of approval for any Phase II environmental testing Buyer wishes to conduct.

Seller shall provide Buyer with any existing Phase I Environmental Assessments, current ALTA surveys, soils reports, and any other documents relevant to the Property in its possession within ten (10) days from the opening of escrow. Seller shall provide Buyer with a current Preliminary Title Reports with plotted exceptions and underlying schedule B documents no later than ten (10) days after opening of Escrow.

Escrow and Title Works:
Escrow shall be established with Lawyers Title Insurance Company ("Escrow"). The Escrow shall be deemed to be opened upon the Escrow's receipt of the fully executed Purchase Agreement (which shall include Escrow Instructions) and the REDACTED Initial Deposit. Said funds are to be deposited into an interest bearing account, with interest accruing to the benefit of Buyer. Title shall be evidenced by a Grant Deed ("Deed") with standard coverage title insurance to be provided by Lawyers Title Insurance Company, at Seller's expense. Buyer may elect to obtain an ALTA extended owners policy, provided that Buyer shall be responsible for the difference in premium and the cost of an ALTA survey.

Prorations and Closing Costs:
At escrow closing, Seller shall pay one-half (½) of the Escrow fee, the premium for the Standard Coverage policy of title insurance for the amount of the purchase price, any transfer taxes and other costs properly chargeable in accordance with the prevailing custom in Ventura County, California. Property taxes for the tax year 2013 shall be prorated as of the date of recordation of the Deed.

Property Condition:
The Property is being sold in its current "as is" condition. Seller warrants to maintain Property in its current condition during Escrow period.

Possession:
Possession shall be delivered to Buyer upon close of Escrow.

Close of Escrow:
The close of Escrow shall be within 30 days from the expiration of the Inspection/Feasibility period.

Authority to Execute:
The parties signing below represent and warrant that they have the authority to bind the entities on whose behalf they are signing.

Brokerage Fees:
Upon the close of Escrow, Seller agrees to pay Brokers a real estate Brokerage Fee in a sum equal to 5% of the Purchase Price.

Buyer's Work Product:
In the event that Buyer fails to close Escrow or cancels Escrow for any reason, Seller shall be entitled to receive copies of any and all reports, including, but not limited to, soil studies, environmental studies, civil engineering reports, plans and specifications that have been prepared by or at the direction of Buyer in connection with Buyer's evaluation of the Property. In addition, Buyer shall provide Seller with copies of any and all correspondence with city or governmental officials, which relates to the Property or its uses or development.

This letter/proposal is intended solely as a preliminary expression of general intentions and is to be used for discussion purposes only. The parties intend that neither shall have any contractual obligations to the other with respect to the matters referred herein unless and until a definitive agreement has been fully executed and delivered by the parties. The parties agree that this letter/proposal is not intended to create any agreement or obligation by either party to negotiate a definitive lease/purchase and sale agreement and imposes no duty whatsoever on either party to continue negotiations, including without limitation any obligation to negotiate in good faith or in any way other than at arm's length. Prior to delivery of a definitive executed agreement, and without any liability to the other party, either party may (1) propose different terms from those summarized herein, (2) enter into negotiations with other parties and/or (3) unilaterally terminate all negotiations with the other party hereto.

If the terms and conditions of this letter are acceptable, please indicate your approval with your signature. In the event that Seller does not sign this letter on or before Wednesday, July 17, 2013, the terms and conditions outlined in this letter shall be considered to be withdrawn by Buyer.

We look forward to your favorable response.

Sincerely,

Paul Farry

Paul Farry

Approved and accepted this ____________ day of ______________________, 2013.

Seller: **CCP Composites USA**	**Buyer:** **NRG Energy, Inc.**
By: ______________________	**By:** John Chillemi
Name Printed: ______________	**Name Printed: John Chillemi**
Title: ______________________	**Title: Senior Vice President**
Date: ______________________	**Date: July 11, 2013**

3. Mark Hale

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State of California

Energy Resources

Conservation and Development Commission

In the Matter of: Application for Certification for the PUENTE POWER PROJECT	Docket No. 15-AFC-01 EXPERT DECLARATION OF MARK HALE REGARDING ALTERNATIVE SITES - ARCHEOLOGICAL RESOURCES

I, Mark Hale, declare as follows:

1. I am employed by AECOM, which has been retained by the Applicant to conduct certain analyses associated with the proposed Puente Power Project (Project), and am duly authorized to make this declaration.

2. I earned a Bachelor of Arts degree in Anthropology from the University of California, Berkeley in 1983. I also successfully completed all classwork, examinations, and defense of Master's thesis towards a Master's degree in Cultural Resources Management from Sonoma State University. I have over 30 years of experience regarding the evaluation of archaeological resources. A copy of my current curriculum vitae is attached to this declaration as Attachment A. Based on my education, training and experience, I am qualified to provide expert testimony as to the matters addressed herein.

3. Except where stated on information and belief, the facts set forth herein are true of my own personal knowledge, and the opinions set forth herein are true and correct articulations of my opinions. If called as a witness, I could and would testify competently to the facts and opinions set forth herein.

4. I prepared or participated in preparing, and am knowledgeable of the contents of Applicant's Exhibit No. 1009: Application for Certification Section 4.3, Cultural Resources (portions pertaining to archeological resources) (CEC TN #204219-10).

Del Norte/Fifth Street Off-Site Alternative

5. The CEC Staff's Final Staff Assessment (FSA), Part 1, Section 4.2 Alternatives concludes that it is "indeterminate" if any surficial or buried archaeological resources or ethnographic resources could be impacted at the Del Norte/Fifth Street Off-Site Alternative site and how such an impact (if it occurred) would compare to the proposed Project site where no impact is identified (FSA, p. 4.2-62).

6. I conducted further evaluation of the Del Norte/Fifth Street Off-Site Alternative to determine the potential for development on this site to result in significant impacts on archaeological resources. The site address is 390 S. Del Norte Boulevard near the intersection with E. Fifth Street. The site is located on the south half of an approximately 25-acre parcel with APN 2160160295.

7. A records search was completed for the Del Norte/Fifth Street Off-Site Alternative at the South Central Coastal Information Center (SCCIC) of the California Historical Resource Information System (CHRIS) on January 11, 2017. The records search area was based on CEC guidelines and addressed the alternative site and estimated routes for necessary linear features based on proximity to the nearest available utility connections.

8. The base maps of the SCCIC indicated that 15 previously recorded archaeological resources occur within the records search area; all are prehistoric in nature with eight representing archaeological sites and the remaining seven being isolated finds. None of the archaeological resources have been formally evaluated for inclusion to the National Register of Historic Places. Six of the identified archaeological sites are located within, or immediately adjacent to, the estimated footprint inclusive of the necessary linear features. The remaining two archaeological sites, and all of the isolated finds, occur within approximately 500 feet of the centerline of the estimated linear alignments. Taking into consideration that a CEC-mandated buffer of 50 feet must be added to each side of a right-of way in order to define the requisite

Project Area of Analysis, these additional archaeological resources may fall within locales considered to be potential impact areas by the CEC.

9. Based on the information and analysis described herein, it is my expert opinion that development of a power plant on the Del Norte/Fifth Street Off-Site Alternative presents a greater likelihood of adverse impacts to archaeological resources than development of the Project at its proposed location, where no impact is identified.

Ormond Beach Area Off-Site Alternative

10. The FSA, Part 1, Section 4.2 Alternatives concludes that potential for impacts to surficial and buried archaeological resources or ethnographic resources at the Ormond Beach Area Off-Site Alternative would be similar to the potential for impacts at the proposed Project site (FSA, p. 4.2-103).

11. However, the records search completed by CEC Staff for the Ormond Beach Area Off-Site Alternative did not include the routes of the necessary linear facilities. It is thus "indeterminate" if any surficial or buried archaeological resources or ethnographic resources could be impacted by the Ormond Beach Area Off-Site Alternative due to construction of the linear facilities. Development of the Project at the proposed site avoids the need to construct any new linear facilities.

12. Based on the information and analysis described herein, it is my expert opinion that, due to the uncertainty associated with the location of the required linear facilities, development of a power plant on the Ormond Beach Area Off-Site Alternative presents a greater likelihood of adverse impacts to archaeological resources than development of the Project at its proposed location, where no impact is identified.

13. I hereby sponsor this declaration into evidence in these proceedings as Applicant's Exhibit No. 1123.

Executed on January 23, 2017, at SAN FRANCISCO, CA

I declare under penalty of perjury of the laws of the State of California that the foregoing is true and correct.

Mark Hale

ATTACHMENT A

AECOM

Mark Hale
Environmental Documentation: Cultural Resources, Archaeology

Professional History

06/1986 – 11/1990, USDI National Park Service, Yosemite National Park (Archaeologist)
01/1983 - 06-86, Sonoma State University Cultural Resources Facility Employee (Archaeologist)
01/1982 - 12/1982, USDA National Forest Service Employee (Archaeologist)
01/1982 - 01/1983, Santa Rosa Junior College Employee (Anthropology Tutor)

Education

BA, Archaeology, University of California - Berkeley, 1983
Successfully completed all coursework, examinations, and research including thesis defense towards M.A. in Cultural Resources Management, Sonoma State University

Years of Experience

With AECOM: 26
With Other Firms: 7

Training

40-Hour Training OSHA Hazardous Waste Operations

Professional Affiliations

Society for California Archaeology
Archaeological Conservancy

Mr. Hale is responsible for directing cultural resources projects throughout the western United States and Pacific Islands. His professional experience spans over 30 years and includes more than 100 surveying, testing, and data recovery projects conducted within various pacific states and territories. Mr. Hale also has extensive experience conducting Section 106 and/or National Environmental Policy Act (NEPA)-related projects for private developments as well as for federal agencies, including the Federal Emergency Management Agency, National Park Service, Bureau of Land Management, Forest Service, U.S. Army Corps of Engineers, Department of Energy, Postal Service, and various branches of the Department of Defense.

Experience

Senior Project Archaeologist/Cultural Lead, Puente Power Project, Oxnard, California, NRG Oxnard Energy Center, LLC: Directed cultural resource inventory, authored technical report, and authored cultural resources section within environmental compliance document under CEC guidelines.

Senior Project Archaeologist/Cultural Lead NERC Project, PG&E Service Territories, California. Cultural Resources lead for multi-county transmission line improvement project. Team under his direction is responsible for assessing cultural resources sensitivity, providing management recommendations, conducting requisite fieldwork, and cultural resources reports for Pacific Gas and Electric Company.

Senior Project Archaeologist/Cultural Lead Hydrogen Energy California SCS Project, Bakersfield, CA. Directed cultural resource inventory, authored technical report, and authored cultural resources section within environmental compliance document under CEC guidelines for Hydrogen Energy and Department of Energy.

Senior Project Archaeologist/Cultural Lead, Marsh Landing Generating Station, Contra Costa County, California, Mirant Marsh Landing, LLC: Directed cultural resource inventory, authored technical report, and authored cultural resources section within environmental compliance document under CEC guidelines.

Senior Project Archaeologist/Cultural Lead, Willow Pass Generating Station, Pittsburg, California, Mirant Willow Pass, LLC: Directed cultural resource inventory, authored technical report, and authored cultural resources section within environmental compliance document under CEC guidelines.

Senior Project Archaeologist/Cultural Lead, Hydrogen Energy California Project, Bakersfield, California, Hydrogen Energy International, LLC: Directed cultural resource inventory, authored technical report, and authored cultural resources section within environmental compliance document under CEC guidelines.

Senior Project Archaeologist/Cultural Lead, Ten Section Oil Field Project, Bakersfield, California. Directed cultural resource inventory and authored technical report under FERC guidelines of the 1700 acre gas storage project area for TRICOR.

Senior Project Archaeologist/Cultural Lead, San Francisco Public Utilities Commission, San Joaquin Pipeline No. 4 Project Environmental Analysis Services, San Joaquin Valley, California. Senior project archaeologist responsible for archaeological survey of 47-mile-long pipeline, authored a technical report, and was member of the administrative draft environmental impact report (ADEIR) team. Initiating cultural resources permitting activities for archaeological resources.

Project Archaeologist, Pine Tree Canyon Wind Energy Project, Kern County, California, Los Angeles Department of Water and Power: Archaeological inventory and evaluation of a wind energy project in the Tehachapi Range, California.

Project Archaeologist, Cotterel Wind Energy Project, Idaho, Windland Corporation: Archaeological inventory of a wind energy project in the Cotterel Mountains, Idaho.

Project Archaeologist/Cultural Lead, Vista del Sol LNG Terminal and Pipeline, FERC Section 3 and 7c Applications (Confidential Client): Prepared Archaeological Study in support of the EIS and FERC application for LNG terminal on the Gulf Coast.

Project Archaeologist, Salton Sea Unit 6 Project, Imperial County, California: Archaeological inventory of proposed geothermal energy facilities in the Colorado Desert, southern California.

Project Archaeologist, Bighorn Power Generation Project, Clark County, Nevada, Reliant Energy: Archaeological inventory, evaluation, and data recovery for a proposed energy generation facility and transmission line in southern Nevada.

Project Archaeologist, Meadow Valley Generation Project, Lincoln and Clark counties, Nevada, PG&E National Energy Group: Archaeological inventory and evaluation for a proposed energy generation facility and transmission line in southern Nevada.

Project Archaeologist/Cultural Lead, Colusa Power Plant Application for Certification, Colusa County, California, Reliant Energy: Completed record search, conducted archaeological survey, and authored technical section for environmental document proposed power plant in Colusa County, California.

Project Archaeologist, Goldendale Power Plant Project: Completed record search, conducted archaeological survey, and co-authored technical section for environmental document for proposed power plant within the City of Goldendale, Washington.

Project Archaeologist/Cultural Lead, Potrero Power Plant Application for Certification. San Francisco, California, Mirant Corporation: Completed record search, conducted archaeological survey, and authored technical section for environmental document in preparation of power plant expansion, San Francisco, California.

Project Archaeologist/Cultural Lead, Contra Costa Power Plant Application for Certification, Contra Costa County, California, Mirant Corporation: Completed record search, conducted archaeological survey, and authored technical section for environmental document in preparation of power plant expansion.

Project Archaeologist/Cultural Lead, City of Pittsburg, Trans Bay Cable Project Environmental Impact Report (EIR), San Francisco Bay Area, California. Project entails the installation of a 53-mile long cable under San Francisco Bay from the City of Pittsburg to the City of San Francisco. Directed portions of the archaeological field investigation and authored a technical report and the cultural resources section of environmental document.

Project Archaeologist, Olympic Pipeline Company, Cross Cascades Transmission, Seattle and Pasco, Washington. Archaeological survey of transmission corridor between Seattle and Pasco, Washington.

Project Archaeologist, Project Archaeologist, Sierra Pacific Power Company, Alturas Intertie, Reno, Nevada. Conducted archaeological survey and test excavations along route of proposed transmission line across northeastern California.

Project Archaeologist/Cultural Lead, Project Archaeologist, Los Angeles Department of Water and Power, Pine Tree Canyon Wind Energy, Los Angeles, California. Archaeological inventory and evaluation of a wind energy project in the Tehachapi Range.

4. Jeremy Hollins

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Attorneys for Applicant

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Energy Resources

Conservation and Development Commission

In the Matter of: Application for Certification for the PUENTE POWER PROJECT	Docket No. 15-AFC-01 EXPERT DECLARATION OF JEREMY HOLLINS REGARDING ALTERNATIVE SITES - HISTORIC ARCHITECTURAL RESOURCES

I, Jeremy Hollins, declare as follows:

1. I am employed by AECOM, which has been retained by the Applicant to conduct certain analyses associated with the proposed Puente Power Project (Project), and am duly authorized to make this declaration.

2. I earned a Masters of Arts in Public History from the University of San Diego in 2005. I have over 14 years of experience regarding the evaluation of historic architectural resources. A copy of my current curriculum vitae is attached to this declaration as Attachment A. Based on my education, training and experience, I am qualified to provide expert testimony as to the matters addressed herein.

3. Except where stated on information and belief, the facts set forth herein are true of my own personal knowledge, and the opinions set forth herein are true and correct articulations of my opinions. If called as a witness I could and would testify competently to the facts and opinions set forth herein.

4. I hereby sponsor this declaration (Applicant's Exhibit No. 1124) into evidence in these proceedings.

5. I prepared or participated in preparing, and am knowledgeable of the contents of Applicant's Exhibit No. 1009: Application for Certification Section 4.3, Cultural Resources (portions pertaining to historic architectural resources) (CEC TN #204219-10).

Ormond Beach Area Off-Site Alternative

6. I evaluated the Ormond Beach Area Off-Site Alternative identified in the Final Staff Assessment (*see,* Final Staff Assessment, page 4.2-76) to determine the potential for development on this site to result in significant impacts on historic architectural resources. The site address is 5980 Arcturus Avenue. The site is composed of two parcels (APNs 2310093155 and 2310093135).

7. The site contains portions of a railroad spur line connected to the Ventura County Railway (VCRR) north of the site. The VCRR is listed as a landmark on the Ventura County Historical Landmarks and Points of Interest (#141-Ventura County). The VCRR is also listed on the California Register of Historical Resources (CRHR), and it was found to be eligible for listing on the National Register of Historic Places (NRHP) under Criterion A by the State Historic Preservation Officer (SHPO) through a Section 106 of the National Historic Preservation Act consultation process for the U.S. Bureau of Reclamation (Reclamation) (2009) Calleguas Hueneme Outfall Replacement Project (BUR090416A).

8. The spur line may date to the period of Kaiser Aluminum, constructed in 1966, and the Reichhold Chemical Company, established in 1967. Or it may date to an earlier period, as California Energy Commission staff observed a section of the spur line track near Hueneme Road stamped with a date of 1922 (*See,* Final Staff Assessment, page 4.2-102). The difference in the design of the spur stops on the site may also indicate different dates of construction.

9. The spur line may be a contributing element to the listed historical resource.

10. As a result of the location of the rail spur, construction of a power plant project similar to the Project at the Ormond Beach Area Off-Site Alternative has the potential to cause a significant impact on a built environment historic architectural resource.

11. Based on the information and analysis described herein, it is my expert opinion that development of a power plant on the Ormond Beach Area Off-Site Alternative presents a significantly greater likelihood of adverse impacts to historic architectural resources than the development of the Project at its proposed location.

Del Norte/Fifth Street Alternative

12. I evaluated the Del Norte/Fifth Street Alternative identified in the Final Staff Assessment (see, Final Staff Assessment, page 4.2-46) to determine the potential for development on this site to result in significant impacts on historic architectural resources. The site address is 390 S. Del Norte Boulevard near the intersection with E. Fifth Street. The site is located on the south half of an approximately 25-acre parcel with APN 2160160295.

13. A records search was completed for the Del Norte/Fifth Street Alternative at the South Central Coastal Information Center (SCCIC) of the California Historical Resource Information System (CHRIS) on January 11, 2017. The records search area was based on CEC guidelines and addressed the alternative site and estimated routes for necessary linear features based on proximity to the nearest available utility connections.

14. The base maps of the SCCIC indicated 10 previously recorded built environment resources occur within the records search area. Two built environment resources within the records search area, the Oxnard Chamber of Commerce-Art Club of Oxnard/Oxnard Public Library and the Henry T. Oxnard Historic District, are listed in the National Register of Historic Places. One additional resource within the search area has not been formally evaluated for eligibility for listing in the National Register of Historic Places or California Register of Historical Resources.

15. An additional 151 built environment resources were found within the records search area in the Historic architectural resources Inventory (HRI) listings. Of the 151 resources, 33 are within close proximity (within or abutting) to the estimated linear routes. Of these 33 resources of the built environment, 27 are listed in, have been determined eligible for listing in, appear eligible (through survey evaluation or other evaluation) for listing in National Register of Historic Places or California Register of Historical Resources, or recognized as

historically significant by local government.

16. Based on the information and analysis described herein, it is my expert opinion that development of a power plant on the Del Norte/Fifth Street Alternative presents a greater likelihood of adverse impacts to historic architectural resources than the development of the Project at its proposed location.

Executed on January 23, 2017, at San Diego, CA

I declare under penalty of perjury of the laws of the State of California that the foregoing is true and correct.

Jeremy Hollins

ATTACHMENT A

Jeremy Hollins, MA
Senior Architectural Historian and Architectural History Team Lead

Professional History

01/2006 - Present, AECOM Senior Architectural Historian
1/2005 - 12/2005, New School of Architecture Adjunct Instructor
12/2004 - 12/2005, IS Architecture Architectural Historian
12/2003 - 12/2005, La Jolla Historical Society Archivist and Preservation Specialist

Education

BA, Environmental History, University of Rhode Island, 2003
MA, Public History, University of San Diego, 2005

Years of Experience

With AECOM: 11
With Other Firms: 2

Training

Annual Conference
Building Partnerships in Tribal Communities
Coordinating Environmental & Historic Preservation Compliance
Introductory and Advanced California Environmental Quality Act Workshop Series
Section 106: Principles and Practice

Certifications

Certificate in Urban Planning (In Progress)

Mr. Hollins is a US Secretary of Interior professional qualified architectural historian and historian who has performed numerous historic evaluations, context studies, and determinations of eligibility and effect for a range of resources. He has extensive experience applying local, state, and National Register criteria to prepare technical reports, California Office of Historic Preservation DPR 523 series forms, historic American buildings survey reports, cultural landscape reports, historic structures reports, and resolution documents. Mr. Hollins has detailed knowledge of the laws and ordinances affecting historic properties, including Section 106 of the National Historic Preservation Act, the California Environmental Quality Act, NEPA, Department of Transportation Act Section 4(f), California Public Resources Code, California state historic building codes, and US Secretary of Interior standards for the treatment of historic properties. Additionally, Mr. Hollins' work has been published in academic journals and he has served as an adjunct instructor in World Architectural History at the New School of Architecture.

Experience

Technical Lead, Puente Power Project Application for Certification, NRG Oxnard Energy Center LLC. Managed the data collection and preparation of the Historic Architecture section of the Application for Certification (CEQA-equivalent document) for the proposed 262 megawatt natural gas-fired generation facility in Oxnard, California. Responsibilities included coordination of field survey, CHRIS records search, Native American consultation, primary and secondary research, development of historic context, recordation and evaluation of historic-period properties through DPR 523 series forms, and analysis of effects

Carson Cogeneration Plan Expansion, BP, Inc., Los Angeles, California. Served as Task Manager for cultural resources assessment for a cogeneration plant expansion. Performed fieldwork and co-authored Cultural Resources AFC section and technical reports. Deliverables were submitted to the CEC in support of a CEQA-level assessment. Duties included coordination of field survey, CHRIS records search, Native American consultation, primary and secondary research, development of historic context, recordation and evaluation of historic-period properties through DPR 523 series forms, analysis of effects, and development of mitigation measures

Carrizo Energy Solar Farm 177 MW Solar Plant, CEC, Ausra, Inc., San Luis Obispo County, California. Served as Task Manager for cultural resources assessment. Performed fieldwork and authored Cultural Resources AFC section and technical report for a 177 MW solar power project located in San Luis Obispo County, California (640 acre solar farm; 380 acre construction laydown). Deliverables were submitted to the CEC in support of a CEQA-level assessment. Duties included coordination of field survey, CHRIS records search, Native American consultation, primary and secondary research, development of historic context, recordation and evaluation of historic-period properties, analysis of effects, and development of mitigation measures.

Stirling Energy Systems, Solar 2 and Data Request 125 - California Energy Commission, Imperial County, California. Performed primary and secondary source research to develop a historic and evaluative context for the project area. Context focused on Imperial County transportation/ circulation networks (Highway 80), local military activities, irrigation agriculture, and the San Diego-Arizona Railroad. Recorded and performed determination of eligibility, analysis of integrity, and identification of effect for six historic period properties.

BrightSource Energy, Rio Mesa Solar Energy Certification Application, Riverside County, California. Field survey and archival research task lead for an approximately 20,000-acre solar project in the Colorado Desert of California. Authored the architectural history portion of cultural resources section of the certification application, which evaluated the direct and indirect impacts of the project to cultural resources. Completed determination of eligibility, analysis of integrity, and identification of effect for 30 resources in accordance with the National Historic Preservation Act, NEPA, California Environmental Quality Act, and California Energy Commission guidelines. Resources were primarily associated with World War II training exercises, desert training center, and other military resources.

US Coast Guard, National Register Evaluations, Various Locations, California. Oversaw the preparation of National Register of Historic Places evaluations of the Point Loma Lighthouse historic district, Air Station Sacramento, and the Morro Bay Harbormaster Office. Developed historic contexts, full-scale evaluations, and integrity assessments based on exhaustive research and field work.

US Marine Corps, Area 26 Museum District, MCB Camp Pendleton, California. Task lead for asset evaluations and site analysis for the museum area district at Camp Pendleton, consisting of the Mechanized Museum and several warehouses constructed during World War II through the end of the Cold War. Developed field forms for each building and created individual timelines, outlining the historic use of each. Provided treatments to meet Secretary of Interior standards for rehabilitation for proposed improvements to the Mechanized Museum to retain the building’s character, feeling, and visual quality, while making compatible changes.

US Marine Corps, Bachelor Enlisted Quarters Siting Study, MCB Camp Pendleton, California. Reviewed MCB Camp Pendleton GIS layers and cultural resources records and data to identify potential direct impacts to previously recorded cultural resources located within a 500-foot radius of proposed bachelor enlisted quarters (BEQ). Provided cultural resources analysis as part of a preliminary NEPA constraints and siting study to support the preparation of the project's design-build request for proposal for fiscal years 2008, 2009, and 2010. In total, 25 potential BEQ sites were analyzed for potential direct impacts to cultural resources.

Naval Facilities Engineering Command Southwest, Building 158 Business Case Analysis (BCA), NB Point Loma, California. Architectural history task manager for a BCA to present and evaluate scenarios regarding the future of Building 158, constructed in 1908 by the Army Quartermaster Corps on present-day NB Point Loma. The BCA included a descriptive scope and viability assessment of five scenarios, the identification and analysis of key events/milestones, opportunities and constraints, stakeholders, decision-making processes, associated estimated costs, and timelines. The five future use scenarios included building rehabilitation, rehabilitation with an expanded footprint, building lay-up (i.e., mothballed), demolition for future use as a parking area, and demolition for use as a buildable site. The report analyzed each of the scenarios, while considering different uses and various occupancies for the building.

US Marine Corps and US Navy, Electrical and Communication Upgrade Military Construction P1093/P1094, MCB Camp Pendleton, California. Coordinated with the MCB Camp Pendleton Environmental Security division archaeologist and Naval Facilities Engineering Command Southwest project manager, as well as the AECOM design and engineering team, to ensure the 100 percent design plans to be submitted to State Historic Preservation Office are in compliance with the project final environmental impact statement and the programmatic agreement. Worked with base staff to identify compatible substitute materials for the replacement of a historic concrete roadway associated with El Camino Real, located at Camp Pendleton. Developed plan for the monitoring of the roadway's removal and replacement.

Marine Corps Recruit Depot (MCRD), Cultural Resources Internal Audit, San Diego, California. Oversaw completion of an internal audit of the MCRD cultural resources program. Task included review of Marine Corps and Department of Defense cultural resource policies and National Historic Preservation Act Section 106 requirements against MCRD records. Produced a report detailing the compliance status of each requirement and presented solutions for the resolution of out-of-compliance items.

US Navy and US Marine Corps, Chocolate Mountain Aerial Gunnery Range Land Withdrawal Renewal, MCAS Yuma, California. Conducted historic research to identify potential cultural resources in the project area of potential effects for the cultural resources section of the legislative environmental impact statement (LEIS). Assumed responsibilities as project manager and oversaw the final studies and certification of LEIS.

Naval Facilities Engineering Command, Desert Installation Appearance Plan and Airfield Security Study, Various Locations, California. Architectural historian responsible for developing cultural resources considerations, basewide historic contexts, design guidelines for historic structures and districts, and basewide visual themes for NAF El Centro, NAS Fallon, NWS Seal Beach, NAS Lemoore, and NAWS China Lake. The bases are desert installations associated with Cold War-era missile and space programs and research and design. NAWS China Lake and NWS Seal Beach feature historic districts associated with NASA's Saturn rocket program, and officers' quarters which housed civilian researchers and military personnel together for the first time. The architecture of the districts reflected the unique functions of each property and the cutting-edge technological and engineering advances conducted onsite. District architecture was distinctively Modern, ranging from the international style to the high-tech style. Architectural historians followed the guidance outlined in the National Register Bulletin Guidelines for Evaluating and Nominating Properties that Have Achieved Significance Within the Past 50 Years and the California Historic Military Buildings and Structures Inventory. A thematic approach was developed to classify each resource within its proper Cold War-era context and ensure each evaluation was rooted in a clear historical perspective.

US Coast Guard, Maintenance Augmentation Team (MAT)/Fast Response Cutters (FRC) Support Facility, USCG Base Los Angeles - Long Beach, California. Completed a constraints study and environmental assessment for locating and planning a MAT/FRC support facility at the base. AECOM evaluated several historic properties at USCG Base San Diego, including an airfield hangar, and at Base Los Angeles - Long Beach, including several industrial piers, docks, and support buildings. Developed historic contexts, historic research, field surveys, and an evaluation and integrity analysis of each property.

US Coast Guard, Novato Spanish Housing Environmental Assessment (EA), Novato, California. Prepared an EA of rehabilitation or demolition of historic properties at the USCG Spanish housing site in Novato. Approximately 132 Spanish-style housing units were reevaluated to determine if they were contributing resources to the National Register-listed Hamilton Army Air Field discontinuous historic district. AECOM also prepared alternatives for rehabilitation, including complete interior demolition and upgrades to interior facilities, and demolition of the housing units and potential construction of new houses or a recreation area, with an emphasis on evaluating character-defining features and the integrity of the historic properties to adhere to US Secretary of the Interior standards for the treatment of historic properties.

University of California - Irvine, International Education Research Foundation Building Historic and Architectural Documentation, Irvine, California. Performed equivalent of historic American buildings survey (HABS) Level 2 survey of a 1986 Frank Gehry-designed academic complex at the University of California – Irvine. Responsible for architectural investigation, physical history, historic context, and coordination with HABS photographer.

Bailey Ranch Historic Resource Assessment, Santa Clara County, CA. Completed historic resource assessment for Bailey Ranch including overseeing architectural history survey, integrity assessment, and assessment of effects for compliance with Section 106 of the NHPA, CEQA, and . Projects considering effects from demolition or relocation of locally historical resource. Required extensive regulatory knowledge of local, state, and federal laws, and strategic planning with Santa Clara Valley Water District to identify best path forward, considering regulatory approvals,

Santa Ana Fixed Guideway, Santa Ana, CA. Cultural Resources Task Manager. Oversaw determination of eligibility, analysis of integrity, and application of criteria for adverse effect for approximately 100 cultural resources in accordance with the NHPA, NEPA, CEQA, and FTA guidelines. Led consultation efforts with SHPO and authored the project MOA. Also, oversaw APE map delineation, stakeholder consultation, historic context development, primary and secondary source research, field map and field form creation, and impact analysis. (Cost: $60,000)

Caltrans and City of Santa Ana, Bristol Street HPSR and HRER, Phase 3 and Phase 4 – Santa Ana, CA. Task manager for an intensive architectural history field survey of the direct APE and a reconnaissance survey of the indirect APE in accordance with the Programmatic Agreement between the FHA, the Advisory Council on Historic Preservation, the California OHP, and Caltrans. Managed archival research, wrote a historic context, evaluated the APE for eligibility for listing in the NRHP and the CRHR (or as historical resources for purposes of CEQA), recorded 66 resources (primarily early to mid-century residences in planned subdivisions) on the appropriate DPR 523 forms, and authored the HPSR and HRER. Adapted unique approach for recordation based on historic subdivisions and property types to facilitate and streamline compliance. (2010-2011)

Caltrans and SANBAG, Lenwood Road HPSR, ASR, and HRER – Barstow, CA. Task manager for cultural resources studies, and preparation of HPSR, ASR, and HRER. Oversaw archival research, historic context, evaluated the project APE for eligibility for listing in the NRHP and the CRHR (or as historical resources for purposes of CEQA), recorded forty-one resources (Historic Route 66-related commercial buildings and single-family residences) on the appropriate DPR 523 forms, and drafted the Historic Resources Evaluation Reports and Historic Properties Survey Reports. (2009-2011).

5. Julie Love
(Wetland Designation)

Michael J. Carroll
LATHAM & WATKINS LLP
650 Town Center Drive, 20th Floor
Costa Mesa, California 92626-1925
Tel.: (714) 540-1235
michael.carroll@lw.com

Attorneys for Applicant

State of California

Energy Resources

Conservation and Development Commission

In the Matter of: Application for Certification for the PUENTE POWER PROJECT	Docket No. 15-AFC-01 EXPERT DECLARATION OF JULIE LOVE REGARDING THE PRESENCE OF WETLANDS ON THE PUENTE PROJECT SITE

I, Julie Love, declare as follows:

1. I am employed by AECOM, which has been retained by the Applicant to conduct certain analyses associated with the proposed Puente Power Project (Project), and am duly authorized to make this declaration.

2. I earned the degree of Master of Environmental Science and Management in Environmental Science and Management from the University of California, Santa Barbara in 2003. I earned the degree of Bachelor of Science in Marine Biology from the University of California, Los Angeles in 2000. I have over 15 years of experience regarding the evaluation of biological resources, including extensive experience conducting wetland delineations and jurisdictional determinations. A copy of my current curriculum vitae is attached to this declaration as Attachment A. Based on my education, training and experience, I am qualified to provide expert testimony as to the matters addressed herein.

3. For purposes of this declaration, the term "Project Site" refers to the parcel of land within the existing Mandalay Generating Station property on which the main components of the Project are to be constructed, and does not necessarily include other areas where Project

related work will take place (e.g., the location of the existing ocean outfall that will be removed as part of the Project).

4. I prepared or participated in preparing, and am knowledgeable of the contents of, the following Applicant's Exhibits:

- Applicant's Exhibit No. 1008: Application for Certification Section 4.2, Biological Resources (CEC TN #204219-9); and
- Applicant's Exhibit No. 1028: Application for Certification, Appendix D, Biological Resources (CEC TN #204220-4).

5. I conducted the associated fieldwork and have reviewed the United States Army Corp of Engineers (USACOE) Wetland Determination Data Forms prepared for the Project Site contained in Appendix D-4 of the Application for Certification.

6. I have reviewed those portions of the "California Coastal Commission's 30413(d) Report for the Proposed NRG Energy Center Oxnard, LLC Puente Power Project – Application for Certification #15-AFC-01" (CEC TN #213667) ("Coastal Commission Report") pertaining to biological resources, including Attachment C – Wetlands Delineation Memorandum.

7. I personally conducted on-site assessments of the Project Site on March 12, 2015, April 2, 2015, November 19, 2015 and October 18, 2016.

8. Based on the information and analysis contained in the documents referred to in paragraphs 4 and 5 above, my observations during my on-site assessments, and my extensive experience conducting wetland delineations and jurisdictional determinations, I disagree with the conclusion in the Coastal Commission Report, which is incorporated into the CEC Final Staff Assessment, Section 4.3, Biological Resources, that a portion of the Project Site constitute a "wetland." (Coastal Commission Report, p. 13; FSA, pp. 4.2-33 – 4.2-34).

9. The Coastal Commission Report identifies the relevant definitions of a "wetland," which are contained in the California Public Resources Code and California Coastal Commission regulations promulgated thereunder. In my expert opinion, no portion of the Project Site qualifies as a "wetland" under either of the relevant definitions.

10. The California Coastal Act defines a "wetland" as:

> . . . lands within the coastal zone **which may be covered periodically or permanently with shallow water** and include saltwater marshes, freshwater marshes, open or closed brackish water marshes, swamps, mudflats, and fens. (California Public Resources Code § 30121) (emphasis added).

No portion of the Project Site is "covered periodically or permanently with shallow water." The site contains no hydrologic features, receives no hydrologic inputs other than direct rainfall, and is not connected to freshwater or tidal habitats. The Project Site is approximately at elevation 14 feet mean lower low water (MLLW), or approximately 14 above sea level, and is protected by seaward dunes and an earthen berm along the north property line. The top of the dunes are at approximately elevation 20 to 30 feet MLLW, and the top of the berm is at approximately elevation 18 feet MLLW.

11. California Coastal Commission regulations define a "wetland" as:

> . . . land **where the water table is at, near, or above the land surface** long enough to promote the formation of hydric soils or to support the growth of hydrophytes, and shall also include those types of wetlands where vegetation is lacking and soil is poorly developed or absent as a result of frequent or drastic fluctuations of surface water levels, wave action, water flow, turbidity or high concentrations of salt or other substance in the substrate. Such wetlands can be recognized by the presence of surface water or saturated substrate at some time during each year and their location within, or adjacent to, vegetated wetlands or deep-water habitats. (14 California Code of Regulations § 13577(b)(1) (emphasis added).

No portion of the Project Site is affected by a "water table at, near, or above the land surface." The site contains no hydrologic features, receives no hydrologic inputs other than direct rainfall, and is not connected to freshwater or tidal habitats. The Project Site is 5 to 9 feet above any potential subsurface waters.

12. For purposes of implementing Section 404 of the federal Clean Water Act, the USACOE and United States Environmental Protection Agency (EPA) apply a definition similar to that found in the California Coastal Commission regulations. For federal purposes, a wetland is defined as:

> . . . those areas that are inundated or saturated by surface or ground water at a frequency and duration sufficient to support, and that under normal circumstances do support, a prevalence of vegetation

> typically adapted for life in saturated soil conditions. Wetlands generally include swamps, marshes, bogs and similar areas." (40 Code of Federal Regulations § 232.2).

13. The USACOE and EPA interpret the federal definition as a "three parameter definition." The three parameters are: i) hydrophytic vegetation; ii) hydric soils; and iii) wetland hydrology. As indicated in the 1987 ACOE Wetland Delineation Manual, "[e]xcept in certain situations defined in this manual, evidence of a minimum of one positive wetland indicator **from each parameter** (hydrology, soil and vegetation) must be found in order to make a positive wetland determination." (1987 ACOE Wetland Delineation Manual, p. 10) (emphasis added).

14. In contrast, the California Coastal Commission interprets its regulatory definition of "wetland" in 14 CCR § 13577 as a "one parameter definition." As stated in Attachment C to the Coastal Commission Report, "[t]he Coastal Commission has a one parameter wetland definition; the Commission considers an area to be a wetland if it is positive for at least one of three wetland parameters: hydrophytic vegetation, hydric soils, or hydrology." (Coastal Commission Report, Attachment C, p. 1 of 3). Applying this one parameter definition, the Coastal Commission Report concludes that a portion of the Project Site constitutes a "wetland" based on the presence of hydrophytic plants alone. (Coastal Commission Report, p. 13). The Project Site does not exhibit wetland hydrology or hydric soils.

15. Sound wetland science and practice dictates that when a wetland determination is based on the presence of one parameter alone, particularly when the other two parameters are clearly absent, as they are in the case of the Project Site, circumstances surrounding the presence of the one parameter be carefully evaluated. If circumstances suggest that the presence of the one parameter is not a reliable indicator of the site's wetland status, it alone should not provide the basis of a wetland determination.

16. In the case of the Project Site, due to the highly disturbed and anthropogenically influenced nature of the onsite vegetation, the presence of hydrophytic vegetation is not a reliable indicator of the Project Site's wetland status. The presence of wetland indicator plant species on the Project Site is likely the result of stored dredge materials

from the nearby Edison Canal. Because the Edison Canal is a saltwater environment, it is likely that the dredged spoils placed on the Project Site were saturated with saltwater, and that during the time of storage, saltwater infiltrated into soil. Over time, this practice likely resulted in an accumulation of salt, making the soil more suitable for salt tolerant plant species such as woolly seablite, slenderleaf iceplant, and pickleweed. This hypothesis is supported by the fact that none of the surrounding areas in the MGS facility, which exhibit disturbed conditions similar to the Project Site but which were not used for storage of dredged material, support these salt-tolerant hydrophytes.

17. A jurisdictional determination/wetland delineation prepared in March 2015, confirmed that neither hydric soils nor wetland hydrology is present on the Project Site (*See,* Application for Certification Appendix D-4 (Applicant's Exhibit No. 1028). The jurisdictional determination/wetland delineation specifically described the California Coastal Commission's wetland delineation criteria and applied those criteria in its evaluation of the Project Site. The jurisdictional determination/wetland delineation concluded that the Project Site does **not** contain wetlands under the Coastal Commission's criteria.

18. Based on the incorrect conclusion that a wetland exists on the Project Site, the Coastal Commission Report recommends, and the Final Staff Assessment incorporates, a wetland restoration ratio of 4:1 in proposed Condition of Certification BIO-9. Compensatory mitigation should be based on the loss of woolly seablite only because the Project Site does not include wetlands. Further, even if the subject 2.03 acres did constitute a wetland, the recommended 4:1 mitigation ratio is not appropriate given the poor quality of the subject acreage.

19. Wetland mitigation ratios are typically determined based on the functions and values affected versus the function that is being restored, replaced or enhanced such that a 1:1 replacement of both acreage and function is accomplished; that is, if a higher quality mitigation is provided, the mitigation ratio may be lower than if lower quality mitigation is provided. Given the highly disturbed character of the plants identified on the Project Site, the high percentage of non-native species, and general lack of wetland functions, a mitigation ratio

of between 1:1 and 1.5:1 would be appropriate if the mitigation provided consists of moderate to high quality wetlands, and 1.5:1 if the mitigation provided consists of low to moderate quality wetlands.

20. In my expert opinion no portion of the Project Site constitutes a "wetland" under any relevant definition, including the California Coastal Commission's one-parameter definition because, in this particular situation, the presence of hydrophytic vegetation is not a reliable wetland indicator. Furthermore, in my expert opinion, the proposed habitat compensation ratio is too high given the highly disturbed character of the Project Site, and results in mitigation that is not proportionate to the impact. The ratio of 2:1 proposed by the CEC staff in its Preliminary Staff Assessment (TN #211885-1) is more than adequate to mitigate the impact.

21. Except where stated on information and belief, the facts set forth herein are true of my own personal knowledge, and the opinions set forth herein true and correct articulations of my opinions. If called as a witness I could and would testify competently to the facts and opinions set forth herein.

22. I hereby sponsor this declaration into evidence in these proceedings as Applicant's Exhibit No. 1125.

Executed on January 24, 2017, at Santa Barbara, CA.

I declare under penalty of perjury of the laws of the State of California that the foregoing is true and correct.

Julie Love

Julie Love

ATTACHMENT A

AECOM

Julie Love
Senior Restoration Ecologist and Biologist

Education

MESM/Environmental Science and Management/2003/Bren School of Environmental Science and Management, University of California, Santa Barbara

BS/Marine Biology/2000/University of California, Los Angeles

Permits

CDFW Scientific Collecting Permit

USFWS Recovery Permit for Tidewater goby

CDFW Collecting Permit for Plants

Years of Experience

With AECOM: 11

With Other Firms: 4

Training

Surface Water Ambient Monitoring Program (SWAMP), field procedures and bioassessment concepts, presented by California Waterboard, April 2016

California Rapid Assessment Method (CRAM) Estuarine Module, presented by UC Davis Extension, October 2012

California Rapid Assessment Method (CRAM) Practitioner Training and Riverine Module, presented by UC Davis Extension, March 2012

Basic Wetland Delineation Training (40-hour), presented by the Wetland Training Institute, August 2008Basic Wetland Delineation Training (40-hour), presented by the Wetland Training Institute, August 2008

Ms. Love's combined work experience and education provide a wide range of ecological training with over 15 years of experience working in the fields of habitat restoration, botany, marine biology, terrestrial and aquatic wildlife, and ecosystem inventory, assessment, and monitoring. Ms. Love's position at AECOM involves managing and coordinating habitat restoration planning and monitoring, wetland delineations and jurisdictional determinations, biological resource evaluations, botanical surveys and mapping, special-status wildlife surveys, stormwater monitoring, stream and algae monitoring, fish relocation, and database management.

Experience

Biological Resource Evaluation

Technical Lead, Puente Power Project Application for Certification, NRG Oxnard Energy Center LLC. Conducted field efforts for the biology section of the Application for Certification (CEQA-equivalent document) and prepared biological resources sections for the various exhibits prepared thereafter for the proposed 262 megawatt natural gas-fired generation facility in Oxnard, California. Responsibilities included identifying and mapping sensitive biological resources, determining the applicable laws, ordnances, regulations, and standards governing biological resources at the facility, and evaluating the potential impacts and mitigation measures to be implemented during construction and management activities.

Gaviota Marine Terminal, Gaviota Terminal Company, Gaviota, California, 2014-Present. Lead author for the Biological Resources Assessment Report and task leader for the associated biological surveys for the 28 acre remediation and restoration project. The BRAR provided a description of existing biological resources within the Project site and surrounding area, identified any significant impacts to these resources that may result from the proposed Project, and recommended feasible mitigation measures that would avoid or substantially lessen these impacts to biological resources, including monarch butterflies. Lead author of the Conceptual Restoration Plan to restore riparian and upland habitats after remediation is completed in phases, with specific emphasis on improving foraging habitat for the monarch butterfly.

Ekwill Street and Fowler Road Extensions Project, City of Goleta, Goleta, California, 2010 – Present. Lead author of Biological Mitigation and Monitoring Plan for a road construction and extension project crossing over Old San Jose Creek. Components of the Plan include implementation of all mitigation measures including the conceptual restoration plan, native tree inventory and protection plan, pre-construction biological surveys, and avoidance and minimization measures to be implemented during project construction. Co-author of the Biological Resources Report, and lead author of the wetland delineation/jurisdictional determination section.

Wetland Delineations/Assessments and Jurisdictional Determinations

Hyla Crossing, Freeport-McMoRan Oil & Gas, Arroyo Grande, California, 2013 – 2015. Field crew leader and lead author for the wetland delineation/jurisdictional determination of Pismo Creek at the Hyla crossing within the Arroyo Grande Oilfield.

Arroyo Grande Oilfield Phase V, Freeport-McMoRan Oil & Gas, Arroyo Grande, California, 2013. Field crew leader and lead author for the wetland delineation/jurisdictional determination of Pismo Creek and several unnamed drainages within the Arroyo Grande Oilfield. Lead author of off-site mitigation plan. Field crew leader and lead author for the wetland delineation/jurisdictional determination of Pismo Creek and several unnamed drainages within the Arroyo Grande Oilfield. Field crew leader for focused botanical surveys within the Arroyo Grande Oilfield. Technical reviewer for associated report.

Point Pedernales Repair Site, Freeport-McMoRan Oil & Gas, Vandenberg Air Force Base, California, 2013. Field crew leader and lead author for the wetland delineation/jurisdictional determination of three <1 acre sites along three drainages intersecting a pipeline repair site.

Gaviota Road Repair Site, Freeport-McMoRan Oil & Gas, Gaviota, California, February 2013. Field crew leader and lead author for the wetland delineation/jurisdictional determination of a <1-acre site along an unnamed tributary to Gaviota Creek intersecting a pipeline repair site.

Former Hercules Gas Plant, Shell Exploration and Production Company, Gaviota, California, 2009 and 2012. Field crew leader and lead author for the wetland delineation/jurisdictional determination for a 2-acre site along Cañada de la Huerta in 2009. Field crew leader and lead author for the wetland delineation/jurisdictional determination of a <1 acre site along Cañada de la Huerta in 2012.

Mission Village, Legacy, and Entrada Projects, Newhall Land and Farming Company, Santa Clarita Valley, California, 2012-2014. Field crew leader and lead author for the wetland delineation/jurisdictional determination of several canyons in the Santa Clara River watershed within the vicinity of the 12,000 acre Newhall Ranch site in the Santa Clarita Valley, California. Assessed the condition of the canyons using California Rapid Assessment Method (CRAM) and a methodology that was based on a combination of three established methods (CRAM, Hydrogeomorphic Approach [HGM], and Special Area Management Plan Landscape Level Functional Assessment [SAMP LLFA]). Conducted 36 riverine and 2 depresssional CRAMs.

Former Hercules Gas Plant, Shell Exploration and Production Company, Gaviota, California, July 2012. Field crew leader and lead author for the wetland delineation/jurisdictional determination of a <1 acre site along Cañada de la Huerta.

California High Speed Train Project, High Speed Rail Authority, Fresno to Bakersfield, California, September 2011. Assessed the condition of jurisdictional waters, including wetlands, along several alternative high-speed rail alignments between Fresno and Bakersfield in California's Central Valley using CRAM. The aquatic features assessed included

individual vernal pools, vernal pool complexes, and depressional wetlands located on the floor of the Central Valley, as well as riverine wetlands along the Kings River and Poso Creek. A certified CRAM instructor supervised the assessment.

Resource Management and Development Plan Environmental Impact Study/ Environmental Impact Report, Newhall Land and Farming Company, Santa Clarita Valley, California, July and August 2010. Assessed the condition of reference-quality sites, as well as a number of existing compensatory mitigation sites, in the Santa Clara River watershed within the vicinity of the 12,000-acre Newhall Ranch site in the Santa Clarita Valley, California. The assessment methodology was based on a combination of three established methods (CRAM, HGM, and SAMP LLFA).

California High Speed Train Project, High Speed Rail Authority, Bakersfield to Palmdale, California, April 2011. Performed wetland delineations/jurisdictional determinations, and GIS mapping for various segments along the High Speed Rail alignments from Bakersfield to Palmdale, California.

California High Speed Train Project, High Speed Rail Authority, Fresno to Bakersfield, California, 2010. Performed wetland delineations/ jurisdictional determinations, and GIS mapping for various segments along the High Speed Rail alignments from Fresno to Bakersfield.

San Jose Creek Bikeway, City of Goleta, Goleta, California, 2009. Field crew leader and lead author for the wetland delineation/jurisdictional determination for a 0.5-acre site in Goleta Slough.

Former Hercules Gas Plant, Shell Exploration and Production Company, Gaviota, California, 2009. Field crew leader and lead author for the wetland delineation/jurisdictional determination for a 2-acre site along Cañada de la Huerta for the project's Streambed Alteration Agreement and Section 404 Permit.

Resource Management and Development Plan Environmental Impact Study/ Environmental Impact Report, Newhall Land and Farming Company, Santa Clarita Valley, California, 2008. Assisted with the wetland delineation and mapping of jurisdictional waters within the 12,000-acre Newhall Ranch site in the Santa Clarita Valley, California. Assisted with the wetland delineation report.

Botanical Surveys and Mapping

Point Arguello Pipeline Company Repair Site, Freeport-McMoRan Oil & Gas, Gaviota, California, Spring 2015. Performed focused Gaviota tarplant (Deinandra increscens ssp. villosa) surveys for the repair and reference site. Technical reviewer for associated report.

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Tidewater Goby Presence/Absence Survey, Basin E/F Tidal Basin Restoration Project, City of Santa Barbara, Santa Barbara, California, October 2010 and 2011–2012. In 2010, performed presence/absence USFWS protocol surveys for tidewater goby in Tecolotito Creek, Foxtrot Drain, and an existing tidal basin adjacent to the creek prior to construction. Medium water body protocol. Installed and monitored block nets downstream of the work area. Co-author of final report. 8.5 hours. From 2011–2012, performed post-construction presence/absence USFWS protocol surveys for tidewater goby in Tecolotito Creek and a constructed tidal basin. Lead author of final report. 24 hours.

Tidewater Goby and Fish Relocation, Santa Barbara Airport Tecolotito and Carneros Creek Relocation Project, City of Santa Barbara, Santa Barbara, California, August 2006 – November 2008. Captured and relocated tidewater gobies and other fish species from Tecolotito and Carneros Creeks. Performed initial presence/absence USFWS protocol surveys for tidewater goby in all locations prior to construction. Performed presence/absence protocol surveys for tidewater goby in all locations after construction. Medium water body protocol. Managed data collection and compilation. Included as a permitted handler on USFWS Biological Opinion 1-8-06-F-42. Assisted in authoring the final report. 145 hours.

Western Snowy Plover and California Brown Pelican Construction Monitoring, Laguna Channel Tidal Gate Repair Project, City of Santa Barbara, Santa Barbara, California, October – December 2006. Performed clearance survey prior to moving sand from near the launch area at the Santa Barbara Harbor. Monitored for impacts to the birds during construction at the tidal gate.

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U.S. Fish and Wildlife Service Recovery Permit for Tidewater Goby (Eucyclogobius newberryi) #TE-217402-0, February 2010 – present.

California Department of Fish and Wildlife Collecting Permit for State-Designated Endangered, Threatened, or Rare Plants #2081(a)-13-35-V, April 2010 – Present.

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California Rapid Assessment Method (CRAM) Estuarine Module, presented by UC Davis Extension, October 2012

California Rapid Assessment Method (CRAM) Practitioner Training and Riverine Module, presented by UC Davis Extension, March 2012

Basic Wetland Delineation Training (40-hour), presented by the Wetland Training Institute, August 2008

6. Julie Love
(Alternative Sites – Biological Resources)

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State of California

Energy Resources

Conservation and Development Commission

In the Matter of: Application for Certification for the PUENTE POWER PROJECT	Docket No. 15-AFC-01 EXPERT DECLARATION OF JULIE LOVE REGARDING ALTERNATIVE SITES – BIOLOGICAL RESOURCES

I, Julie Love, declare as follows:

1. I am employed by AECOM, which has been retained by the Applicant to conduct certain analyses associated with the proposed Puente Power Project (Project), and am duly authorized to make this declaration.

2. I earned the degree of Master of Environmental Science and Management in Environmental Science and Management from the University of California, Santa Barbara in 2003. I earned the degree of Bachelor of Science in Marine Biology from the University of California, Los Angeles in 2000. I have over 15 years of experience regarding the evaluation of biological resources, including extensive experience conducting wetland delineations and jurisdictional determinations. A copy of my current curriculum vitae is attached to this declaration as Attachment A. Based on my education, training and experience, I am qualified to provide expert testimony as to the matters addressed herein.

3. I prepared or participated in preparing, and am knowledgeable of the contents of, the following Applicant's Exhibits:

- Applicant's Exhibit No. 1008: Application for Certification Section 4.2, Biological

Resources (CEC TN #204219-9); and

- Applicant's Exhibit No. 1028: Application for Certification, Appendix D Biological Resources (CEC TN #204220-4).

4. I have reviewed those portions of CEC Staff's Final Staff Assessment (FSA), Part 1, Section 4.2 Alternatives (TN #214712), pertaining to potential biological resource impacts associated with developing a power plant such as the Project at either of two alternative sites analyzed in detail in the FSA. The two alternative sites are referred to as the Ormond Beach Area Off-Site Alternative (FSA, p. 4.2-76) and the Del Norte/Fifth Street Off-Site Alternative (FSA, p. 4.2-46).

5. I conducted further desktop analysis of the potential for development of the Project at either the Ormond Beach Area Off-Site Alternative or the Del Norte/Fifth Street Off-Site Alternative to adversely affect biological resources. My findings and conclusions are set forth herein.

Ormond Beach Area Off-Site Alternative

6. Mapped partially hydric soils are present within the boundaries of the Ormond Beach Off-Site Alternative site (USDA-NRCS 2016a). On-site soils are generally associated with tidal flat landforms (USDA-NRCS 2016b). Wetland soils are more likely to be present in soils of this type and with these hydric ratings, although the current use of the site may impede their presence or persistence. One of the reasons that CEC Staff concluded that the Ormond Beach Area Off-Site Alternative was environmentally superior to the proposed Project site was the avoidance of impacts to the 2.03-acre area of the Project site that the California Coastal Commission (CCC) defined as "wetlands" based on its one-parameter wetland definition (FSA, p. 4.2-6). If one were to apply the same wetland definition to the Ormond Beach Area Off-Site Alternative, then one-parameter wetlands may be present due to the potential for wetland soils.

7. Several U.S. Fish and Wildlife Service (USFWS)-mapped wetland features, and other potentially jurisdictional water bodies, are present within 0.25 miles of the Ormond Beach Alternative Site, including freshwater emergent wetland and canals/ditches

(USFWS 2016, USGS 2016). These features have the potential to be jurisdictional under U.S. Army Corps of Engineers (USAOCE), California Department of Fish and Wildlife (CDFW), and/or Regional Water Quality Control Board (RWQCB). Mapped Environmentally Sensitive Habitat Areas (ESHAs) within a 0.25 radius of the site include salt marsh/coastal salt water marsh, and flats, both of which are associated with the Ormond Beach wetlands southwest of the site (City 1982). Resource Protection Zones within 0.25 miles include wetland features to the west displayed in the National Wetland Inventory (NWI) dataset and agricultural areas immediately south of the site (City 2011). There is one California Natural Diversity Database (CNDDB) occurrence of a sensitive species within a 0.25 mile radius of the site, the state-listed endangered Belding's savannah sparrow (*Passerculus sandwichensis beldingi*). The Ormond Beach Area Off-Site Alternative is also adjacent to over 500 acres of property proposed for inclusion in the Ormond Beach Wetlands Restoration Project (Ormond Beach Wetland Restoration Project 2016).

8. In my opinion, the Ormond Beach Area Off-Site Alternative is not environmentally superior to the proposed Project site with respect to biological resources. Within the close vicinity of the alternative site there are several sensitive biological resources documented in the literature reviewed, including USFWS and USGS-mapped wetlands and other potentially jurisdictional water bodies, mapped ESHA, sensitive land uses, and sensitive species. Notably, the Ormond Beach Area Off-Site Alternative is adjacent to over 500 acres of property proposed for inclusion in the Ormond Beach Wetlands Restoration Project.

Del Norte/Fifth Street Off-Site Alternative

9. A USGS-mapped canal/ditch is present within the boundaries of the Del Norte/Fifth Street Off-Site Alternative site (USGS 2016), which is potentially jurisdictional under the RWQCB.

10. Mapped partially hydric soils are present within the boundaries of the Del Norte/Fifth Street Offsite Alternative site (USDA-NRCS 2016a). On-site soils are generally associated with tidal flat landforms (USDA-NRCS 2016b). Wetland soils are more likely to be present in soils of this type and with these hydric ratings, although the current use of the site may

impede their presence or persistence. Although very unlikely, there may be potential for wetland vegetation in the southern portion of the site. One justification for considering alternatives sites is avoidance of impacts to the 2.03-acre area of the Project site that the CCC defined as "wetlands" based on its one-parameter definition. If one were to apply the same wetland definition to the Del Norte/Fifth Street Off-Site Alternative, then one-parameter wetlands may be present due to the potential for wetland soils and hydrophytic vegetation.

11. Several USFWS-mapped wetland features and other potentially jurisdictional water bodies are present within 0.25 miles to the Del Norte/Fifth Street Off-Site Alternative site, including freshwater emergent wetland and canals/ditches (USFWS 2016, USGS 2016). These features have the potential to be jurisdictional under USACE, CDFW, and/or RWQCB. There is one CNDDB occurrence of a sensitive species within a 0.25 mile radius of the site, the CDFW Watch List California horned lark (*Eremophila alpestris actia*).

12. In my opinion, the Del Norte/Fifth Street Off-Site Alternative is not environmentally superior to the proposed Project site with respect to biological resources. Within the close vicinity of the alternative site there are several sensitive biological resources documented in the literature reviewed, including USFWS and USGS-mapped wetlands and other potentially jurisdictional water bodies, and sensitive species.

Conclusions

13. Based on the information and analysis described herein, it is my expert opinion that development of a power plant on the Ormond Beach Area Off-Site Alternative presents an equivalent or greater likelihood of adverse impacts to biological resources than development of the Project at its proposed location. Based on the information and analysis described herein, it is my expert opinion that development of a power plant on the Del Norte/Fifth Street Off-Site Alternative presents an equivalent likelihood of adverse impacts to biological resources than development of the Project at its proposed location.

14. Except where stated on information and belief, the facts set forth herein are true of my own personal knowledge, and the opinions set forth herein are true and correct articulations of my opinions. If called as a witness I could and would testify competently to the

facts and opinions set forth herein.

15. I hereby sponsor this declaration into evidence in these proceedings as Applicant's Exhibit No. 1126.

Executed on January 24, 2017, at Santa Barbara, CA.

I declare under penalty of perjury of the laws of the State of California that the foregoing is true and correct.

Julie Love

Julie Love

REFERENCES

U.S. Department of Agriculture, National Resources Conservation Service (USDA-NRCS). 2016a. Soil Survey Geographic (SSURGO) database for CA674, Ventura Area, California (09/21/2016); accessed 12/23/2016 from https://gdg.sc.egov.usda.gov/GDGOrder.aspx.

2016b. Web Soil Survey. https://websoilsurvey.nrcs.usda.gov/app/.

U.S. Fish and Wildlife Service (USFWS). 2016a. National Wetlands Inventory (NWI). V2, accessed 12/27/2016. https://www.fws.gov/wetlands/data/Mapper.html.

U.S. Geological Survey (USGS). 2016. National Hydrography Dataset (NHD). High Res. Pre-staged Subregion, accessed 12/27/2016 https://nhd.usgs.gov/data.html.

City of Oxnard Planning and Environmental Services (City). 2011. 2030 General Plan, Goals and Policies. Issued October 2011.

1982. Coastal Land Use Plan. Issued February 1982.

ATTACHMENT A

AECOM

Julie Love
Senior Restoration Ecologist and Biologist

Education

MESM/Environmental Science and Management/2003/Bren School of Environmental Science and Management, University of California, Santa Barbara
BS/Marine Biology/2000/University of California, Los Angeles

Permits

CDFW Scientific Collecting Permit
USFWS Recovery Permit for Tidewater goby
CDFW Collecting Permit for Plants

Years of Experience

With AECOM: 11
With Other Firms: 4

Training

Surface Water Ambient Monitoring Program (SWAMP), field procedures and bioassessment concepts, presented by California Waterboard, April 2016
California Rapid Assessment Method (CRAM) Estuarine Module, presented by UC Davis Extension, October 2012
California Rapid Assessment Method (CRAM) Practitioner Training and Riverine Module, presented by UC Davis Extension, March 2012
Basic Wetland Delineation Training (40-hour), presented by the Wetland Training Institute, August 2008Basic Wetland Delineation Training (40-hour), presented by the Wetland Training Institute, August 2008

Ms. Love's combined work experience and education provide a wide range of ecological training with over 15 years of experience working in the fields of habitat restoration, botany, marine biology, terrestrial and aquatic wildlife, and ecosystem inventory, assessment, and monitoring. Ms. Love's position at AECOM involves managing and coordinating habitat restoration planning and monitoring, wetland delineations and jurisdictional determinations, biological resource evaluations, botanical surveys and mapping, special-status wildlife surveys, stormwater monitoring, stream and algae monitoring, fish relocation, and database management.

Experience

Biological Resource Evaluation

Technical Lead, Puente Power Project Application for Certification, NRG Oxnard Energy Center LLC. Conducted field efforts for the biology section of the Application for Certification (CEQA-equivalent document) and prepared biological resources sections for the various exhibits prepared thereafter for the proposed 262 megawatt natural gas-fired generation facility in Oxnard, California. Responsibilities included identifying and mapping sensitive biological resources, determining the applicable laws, ordnances, regulations, and standards governing biological resources at the facility, and evaluating the potential impacts and mitigation measures to be implemented during construction and management activities.

Gaviota Marine Terminal, Gaviota Terminal Company, Gaviota, California, 2014-Present. Lead author for the Biological Resources Assessment Report and task leader for the associated biological surveys for the 28 acre remediation and restoration project. The BRAR provided a description of existing biological resources within the Project site and surrounding area, identified any significant impacts to these resources that may result from the proposed Project, and recommended feasible mitigation measures that would avoid or substantially lessen these impacts to biological resources, including monarch butterflies. Lead author of the Conceptual Restoration Plan to restore riparian and upland habitats after remediation is completed in phases, with specific emphasis on improving foraging habitat for the monarch butterfly.

Ekwill Street and Fowler Road Extensions Project, City of Goleta, Goleta, California, 2010 – Present. Lead author of Biological Mitigation and Monitoring Plan for a road construction and extension project crossing over Old San Jose Creek. Components of the Plan include implementation of all mitigation measures including the conceptual restoration plan, native tree inventory and protection plan, pre-construction biological surveys, and avoidance and minimization measures to be implemented during project construction. Co-author of the Biological Resources Report, and lead author of the wetland delineation/jurisdictional determination section.

Wetland Delineations/Assessments and Jurisdictional Determinations

Hyla Crossing, Freeport-McMoRan Oil & Gas, Arroyo Grande, California, 2013 – 2015. Field crew leader and lead author for the wetland delineation/jurisdictional determination of Pismo Creek at the Hyla crossing within the Arroyo Grande Oilfield.

Arroyo Grande Oilfield Phase V, Freeport-McMoRan Oil & Gas, Arroyo Grande, California, 2013. Field crew leader and lead author for the wetland delineation/jurisdictional determination of Pismo Creek and several unnamed drainages within the Arroyo Grande Oilfield. Lead author of off-site mitigation plan. Field crew leader and lead author for the wetland delineation/jurisdictional determination of Pismo Creek and several unnamed drainages within the Arroyo Grande Oilfield. Field crew leader for focused botanical surveys within the Arroyo Grande Oilfield. Technical reviewer for associated report.

Point Pedernales Repair Site, Freeport-McMoRan Oil & Gas, Vandenberg Air Force Base, California, 2013. Field crew leader and lead author for the wetland delineation/jurisdictional determination of three <1 acre sites along three drainages intersecting a pipeline repair site.

Gaviota Road Repair Site, Freeport-McMoRan Oil & Gas, Gaviota, California, February 2013. Field crew leader and lead author for the wetland delineation/jurisdictional determination of a <1-acre site along an unnamed tributary to Gaviota Creek intersecting a pipeline repair site.

Former Hercules Gas Plant, Shell Exploration and Production Company, Gaviota, California, 2009 and 2012. Field crew leader and lead author for the wetland delineation/jurisdictional determination for a 2-acre site along Cañada de la Huerta in 2009. Field crew leader and lead author for the wetland delineation/jurisdictional determination of a <1 acre site along Cañada de la Huerta in 2012.

Mission Village, Legacy, and Entrada Projects, Newhall Land and Farming Company, Santa Clarita Valley, California, 2012-2014. Field crew leader and lead author for the wetland delineation/jurisdictional determination of several canyons in the Santa Clara River watershed within the vicinity of the 12,000 acre Newhall Ranch site in the Santa Clarita Valley, California. Assessed the condition of the canyons using California Rapid Assessment Method (CRAM) and a methodology that was based on a combination of three established methods (CRAM, Hydrogeomorphic Approach [HGM], and Special Area Management Plan Landscape Level Functional Assessment [SAMP LLFA]). Conducted 36 riverine and 2 depresssional CRAMs.

Former Hercules Gas Plant, Shell Exploration and Production Company, Gaviota, California, July 2012. Field crew leader and lead author for the wetland delineation/jurisdictional determination of a <1 acre site along Cañada de la Huerta.

California High Speed Train Project, High Speed Rail Authority, Fresno to Bakersfield, California, September 2011. Assessed the condition of jurisdictional waters, including wetlands, along several alternative high-speed rail alignments between Fresno and Bakersfield in California's Central Valley using CRAM. The aquatic features assessed included

individual vernal pools, vernal pool complexes, and depressional wetlands located on the floor of the Central Valley, as well as riverine wetlands along the Kings River and Poso Creek. A certified CRAM instructor supervised the assessment.

Resource Management and Development Plan Environmental Impact Study/ Environmental Impact Report, Newhall Land and Farming Company, Santa Clarita Valley, California, July and August 2010. Assessed the condition of reference-quality sites, as well as a number of existing compensatory mitigation sites, in the Santa Clara River watershed within the vicinity of the 12,000-acre Newhall Ranch site in the Santa Clarita Valley, California. The assessment methodology was based on a combination of three established methods (CRAM, HGM, and SAMP LLFA).

California High Speed Train Project, High Speed Rail Authority, Bakersfield to Palmdale, California, April 2011. Performed wetland delineations/jurisdictional determinations, and GIS mapping for various segments along the High Speed Rail alignments from Bakersfield to Palmdale, California.

California High Speed Train Project, High Speed Rail Authority, Fresno to Bakersfield, California, 2010. Performed wetland delineations/ jurisdictional determinations, and GIS mapping for various segments along the High Speed Rail alignments from Fresno to Bakersfield.

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U.S. Fish and Wildlife Service Recovery Permit for Tidewater Goby (Eucyclogobius newberryi) #TE-217402-0, February 2010 – present.

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Basic Wetland Delineation Training (40-hour), presented by the Wetland Training Institute, August 2008

7. Julie Love
(Response to Statements of Lawrence E. Hunt and Ilene Anderson regarding Biological Resources)

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State of California

Energy Resources

Conservation and Development Commission

In the Matter of:
Application for Certification
for the PUENTE POWER PROJECT

Docket No. 15-AFC-01

EXPERT DECLARATION OF JULIE LOVE IN RESPONSE TO STATEMENTS OF LAWRENCE E. HUNT AND ILENE ANDERSON REGARDING BIOLOGICAL RESOURCES

I, Julie Love, declare as follows:

1. I am employed by AECOM, which has been retained by the Applicant to conduct certain analyses associated with the proposed Puente Power Project (Project), and am duly authorized to make this declaration.

2. I earned the degree of Master of Environmental Science and Management in Environmental Science and Management from the University of California, Santa Barbara in 2003. I earned the degree of Bachelor of Science in Marine Biology from the University of California, Los Angeles in 2000. I have over 15 years of experience regarding the evaluation of biological resources, including extensive experience conducting wetland delineations and jurisdictional determinations. A copy of my current curriculum vitae is attached to this declaration as Attachment A. Based on my education, training and experience, I am qualified to provide expert testimony as to the matters addressed herein.

3. Except where stated on information and belief, the facts set forth herein are true of my own personal knowledge, and the opinions set forth herein are true and correct

articulations of my opinions. If called as a witness I could and would testify competently to the facts and opinions set forth herein.

4. I hereby sponsor this declaration into evidence in these proceedings as Applicant's Exhibit No. 1127.

5. I prepared or participated in preparing, and am knowledgeable of the contents of, the following Applicant's Exhibits:

- Applicant's Exhibit No. 1008: Application for Certification Section 4.2, Biological Resources (CEC TN #204219-9); and
- Applicant's Exhibit No. 1028: Application for Certification, Appendix D Biological Resources (CEC TN #204220-4);
- Applicant's Exhibit No. 1064: Project Enhancement and Refinement - Demolition of Mandalay Generating Station Units 1 and 2 (Section 4.2) (CEC TN #206698);
- Applicant's Exhibit No. 1086: Response to Recommended Specific Provisions in August 26, 2016 Proposed Report (CEC TN # 213624);
- Applicant's Exhibit No. 1087: Comments on California Coastal Commission Report to California Energy Commission on AFC 15-AFC-01 - NRG Puente Power Project (CEC TN # 213625);
- Applicant's Exhibit No. 1088: Final NRG Comment Letter to California Coastal Commission re: Agenda Item F10a, September 9, 2016 (CEC TN # 213626); and
- Applicant's Exhibit No. 1090: Puente Power Project (P3), Project Enhancement – Outfall Removal and Beach Restoration (Section 3.2) (CEC TN #213802).

6. I have reviewed those portions of the "California Coastal Commission's 30413(d) Report for the Proposed NRG Energy Center Oxnard, LLC Puente Power Project – Application for Certification #15-AFC-01" (CEC TN #213667) ("Coastal Commission Report") pertaining to biological resources, including Attachment C – Wetlands Delineation Memorandum.

7. I have reviewed the statement of Lawrence E. Hunt submitted by intervener Environmental Defense Center/Environmental Coalition/Sierra Club Los Padres

Chapter (collectively, "EDC") (CEC TN # 215434) and identified as EDC Exhibit No. 4017 ("Hunt Statement").

8. I have reviewed the statement of Ilene Anderson submitted by intervener Center for Biological Diversity ("CBD") (CEC TN # 215431-1) and identified as CBD Exhibit No. 7022 ("Anderson Statement").

9. For purposes of this declaration, the term "Project Site" refers to the parcel of land within the existing Mandalay Generating Station property on which the main components of the Project are to be constructed, and does not necessarily include other areas where Project related work will take place (e.g., the location of the existing ocean outfall that will be removed as part of the Project).

Response to Hunt Statement

10. As explained in detail in Applicant's Exhibit No. 1125, I disagree with the conclusion in the Coastal Commission Report, which is incorporated into the CEC Final Staff Assessment, that a portion of the Project Site constitutes a "wetland." Although the Project Site exhibits a predominance of hydrophytic vegetation, this vegetation is a result of chronic disturbance and human intervention, and is not indicative of wetland conditions. No portion of the Project Site is "covered periodically or permanently with shallow water." The site contains no hydrologic features, receives no hydrologic inputs other than direct rainfall, and is not connected to freshwater or tidal habitats. The site has been used for a variety of functions over the life of the Mandalay Generating Station, including use as lay down area for construction equipment and materials, storage area for concrete rubble, gravel, other clean construction debris, and most recently for long-term storage of material dredged from the bottom of the Edison Canal. Throughout the history of the existing power station, and prior to its construction, the site has never been, nor has it functioned as a wetland.

11. Although valuable habitat for wildlife species is located in the immediate Project vicinity (i.e., McGrath Lake and coastal dunes), the Project Site itself has been graded and subjected to various human uses in the past, and the vegetation is significantly disturbed. The likelihood of these disturbed habitats to support sensitive wildlife species is low.

12. The on-site coyote bush scrub is an upland vegetation type dominated by coyote bush (*Baccharis pilularis*), an upland species that is not a wetland indicator. The on-site coyote bush scrub does not support wetlands, is highly disturbed, and invasive species are prevalent. Mulefat (*Baccharis salicifolia*) thickets are not located on-site, but are located off-site to the north within a relatively recently installed habitat restoration area.

13. I agree with the CEC Staff conclusions in the FSA that the Project will not cause significant impacts to sensitive habitats or sensitive species in the surrounding area. The Project will implement several avoidance and minimization measures that will substantially protect and reduce impacts to the biological resources present on-site and in the immediate Project vicinity, such as the presence of an on-site designated biologist, implementation of pre-construction surveys, implementation of a Worker Environmental Awareness Program, the preparation of a Biological Resources Mitigation Implementation and Monitoring Plan, etc.

Response to Anderson Statement

14. In the Application for Certification Section 4.2, Biological Resources (Applicant's Exhibit No. 1008) and Project Enhancement - Outfall Removal and Beach Restoration (Applicant's Exhibit No. 1090), it was conservatively described that there could be the potential for tidewater goby to be present in the Edison Canal as the species is known to occur within the 10-mile regional study area for biological resources evaluated for the Project. However, based on water quality and habitat requirements for tidewater goby outlined in U.S. Environmental Protection Agency (USEPA) and U.S. Fish and Wildlife Services (USFWS) documents and conditions observed during on-site surveys, the portion of Edison Canal near the proposed discharge point is not suitable habitat for the tidewater goby. While tidewater gobies may have the ability to tolerate salinities for a period of time as high as 42 parts per thousand (ppt), it is not favorable for long-term survival and reproduction. The USFWS Tidewater Goby Recovery Plan states, "the species is typically found in waters with salinities of less than 12 ppt". The salinity in the Edison Canal near the proposed discharge is typically very close to the salinity of the Pacific Ocean ($\geq$37 ppt), which is where Edison Canal originates. The amount of wastewater generated by the Project (approximately 6.5 acre-feet per year) would be intermittent

and small in comparison to the tidal prism of the canal and would not substantially change the turbidity, salinity, temperature, pH or other relevant chemical constituent in the canal. The Recovery Plan states that tidewater gobies spend all life stages in lagoons, estuaries, and river mouths. The Edison Canal does not qualify as a lagoon, estuary, or river mouth. Regarding life history, the Tidewater Goby Recovery Plan states that tidewater gobies move upstream in summer and fall, with reproduction occurring in these upstream tributaries. The Edison Canal has no "upstream" habitat consistent with that required for consistent tidewater goby reproduction. Therefore, I agree with the statement in the FSA that the tidewater goby is not expected in the canal due to high salinity levels.

15. California Least Tern (*Sterna antillarum browni*) is a federally-listed endangered, state-listed endangered, and state fully-protected species. Nesting birds, including California Least Tern, would not be significantly impacted by the demolition of the outfall because the demolition of the outfall structure will be conducted outside the nesting season (February 1 through August 31). The Project will employ several avoidance and minimization measures that will substantially protect and reduce impacts to the biological resources present on-site and in the immediate Project vicinity, such as the on-site designated biologist, pre-construction surveys, implementation of a worker environmental awareness program, the preparation of a Biological Resources Mitigation Implementation and Monitoring Plan, etc. With avoiding construction in the nesting season and the implementation of proposed Conditions of Certifications, no "take" of fully protected species is anticipated.

16. Ventura marsh milk-vetch (*Astragalus pycnostachyus* var. *lanosissimus*) is a federally and state-listed endangered plant, and a CNPS Rank 1B.1 species. Ventura marsh milk-vetch was not observed on the Project site. As documented in the Application for Certification Section 4.2, Biological Resources (Applicant's Exhibit No. 1008) and the Project Enhancement-Outfall Removal and Beach Restoration (Applicant's Exhibit No. 1090), there is low potential for Ventura marsh milk-vetch to occur on the Project site and along the beach near the outfall structure. Although the literature reviewed during the Application for Certification did not indicate a population located at the mitigation planting site for the North Shore at Mandalay

Bay development project, the Project will employ several avoidance and minimization measures that will substantially protect and reduce impacts to the biological resources present on-site and in the immediate Project vicinity, such as the presence of an on-site designated biologist, implementation of pre-construction surveys, implementation of a Worker Environmental Awareness Program, the preparation of a Biological Resources Mitigation Implementation and Monitoring Plan, etc.

Executed on January 24, 2017, at Santa Barbara, CA.

I declare under penalty of perjury of the laws of the State of California that the foregoing is true and correct.

Julie Love

Julie Love

ATTACHMENT A

Julie Love
Senior Restoration Ecologist and Biologist

Education

MESM/Environmental Science and Management/2003/Bren School of Environmental Science and Management, University of California, Santa Barbara
BS/Marine Biology/2000/University of California, Los Angeles

Permits

CDFW Scientific Collecting Permit
USFWS Recovery Permit for Tidewater goby
CDFW Collecting Permit for Plants

Years of Experience

With AECOM: 11
With Other Firms: 4

Training

Surface Water Ambient Monitoring Program (SWAMP), field procedures and bioassessment concepts, presented by California Waterboard, April 2016
California Rapid Assessment Method (CRAM) Estuarine Module, presented by UC Davis Extension, October 2012
California Rapid Assessment Method (CRAM) Practitioner Training and Riverine Module, presented by UC Davis Extension, March 2012
Basic Wetland Delineation Training (40-hour), presented by the Wetland Training Institute, August 2008Basic Wetland Delineation Training (40-hour), presented by the Wetland Training Institute, August 2008

Ms. Love's combined work experience and education provide a wide range of ecological training with over 15 years of experience working in the fields of habitat restoration, botany, marine biology, terrestrial and aquatic wildlife, and ecosystem inventory, assessment, and monitoring. Ms. Love's position at AECOM involves managing and coordinating habitat restoration planning and monitoring, wetland delineations and jurisdictional determinations, biological resource evaluations, botanical surveys and mapping, special-status wildlife surveys, stormwater monitoring, stream and algae monitoring, fish relocation, and database management.

Experience

Biological Resource Evaluation

Technical Lead, Puente Power Project Application for Certification, NRG Oxnard Energy Center LLC. Conducted field efforts for the biology section of the Application for Certification (CEQA-equivalent document) and prepared biological resources sections for the various exhibits prepared thereafter for the proposed 262 megawatt natural gas-fired generation facility in Oxnard, California. Responsibilities included identifying and mapping sensitive biological resources, determining the applicable laws, ordnances, regulations, and standards governing biological resources at the facility, and evaluating the potential impacts and mitigation measures to be implemented during construction and management activities.

Gaviota Marine Terminal, Gaviota Terminal Company, Gaviota, California, 2014-Present. Lead author for the Biological Resources Assessment Report and task leader for the associated biological surveys for the 28 acre remediation and restoration project. The BRAR provided a description of existing biological resources within the Project site and surrounding area, identified any significant impacts to these resources that may result from the proposed Project, and recommended feasible mitigation measures that would avoid or substantially lessen these impacts to biological resources, including monarch butterflies. Lead author of the Conceptual Restoration Plan to restore riparian and upland habitats after remediation is completed in phases, with specific emphasis on improving foraging habitat for the monarch butterfly.

Ekwill Street and Fowler Road Extensions Project, City of Goleta, Goleta, California, 2010 – Present. Lead author of Biological Mitigation and Monitoring Plan for a road construction and extension project crossing over Old San Jose Creek. Components of the Plan include implementation of all mitigation measures including the conceptual restoration plan, native tree inventory and protection plan, pre-construction biological surveys, and avoidance and minimization measures to be implemented during project construction. Co-author of the Biological Resources Report, and lead author of the wetland delineation/jurisdictional determination section.

Wetland Delineations/Assessments and Jurisdictional Determinations
Hyla Crossing, Freeport-McMoRan Oil & Gas, Arroyo Grande, California, 2013 – 2015. Field crew leader and lead author for the wetland delineation/jurisdictional determination of Pismo Creek at the Hyla crossing within the Arroyo Grande Oilfield.

Arroyo Grande Oilfield Phase V, Freeport-McMoRan Oil & Gas, Arroyo Grande, California, 2013. Field crew leader and lead author for the wetland delineation/jurisdictional determination of Pismo Creek and several unnamed drainages within the Arroyo Grande Oilfield. Lead author of off-site mitigation plan. Field crew leader and lead author for the wetland delineation/jurisdictional determination of Pismo Creek and several unnamed drainages within the Arroyo Grande Oilfield. Field crew leader for focused botanical surveys within the Arroyo Grande Oilfield. Technical reviewer for associated report.

Point Pedernales Repair Site, Freeport-McMoRan Oil & Gas, Vandenberg Air Force Base, California, 2013. Field crew leader and lead author for the wetland delineation/jurisdictional determination of three <1 acre sites along three drainages intersecting a pipeline repair site.

Gaviota Road Repair Site, Freeport-McMoRan Oil & Gas, Gaviota, California, February 2013. Field crew leader and lead author for the wetland delineation/jurisdictional determination of a <1-acre site along an unnamed tributary to Gaviota Creek intersecting a pipeline repair site.

Former Hercules Gas Plant, Shell Exploration and Production Company, Gaviota, California, 2009 and 2012. Field crew leader and lead author for the wetland delineation/jurisdictional determination for a 2-acre site along Cañada de la Huerta in 2009. Field crew leader and lead author for the wetland delineation/jurisdictional determination of a <1 acre site along Cañada de la Huerta in 2012.

Mission Village, Legacy, and Entrada Projects, Newhall Land and Farming Company, Santa Clarita Valley, California, 2012-2014. Field crew leader and lead author for the wetland delineation/jurisdictional determination of several canyons in the Santa Clara River watershed within the vicinity of the 12,000 acre Newhall Ranch site in the Santa Clarita Valley, California. Assessed the condition of the canyons using California Rapid Assessment Method (CRAM) and a methodology that was based on a combination of three established methods (CRAM, Hydrogeomorphic Approach [HGM], and Special Area Management Plan Landscape Level Functional Assessment [SAMP LLFA]). Conducted 36 riverine and 2 depresssional CRAMs.

Former Hercules Gas Plant, Shell Exploration and Production Company, Gaviota, California, July 2012. Field crew leader and lead author for the wetland delineation/jurisdictional determination of a <1 acre site along Cañada de la Huerta.

California High Speed Train Project, High Speed Rail Authority, Fresno to Bakersfield, California, September 2011. Assessed the condition of jurisdictional waters, including wetlands, along several alternative high-speed rail alignments between Fresno and Bakersfield in California's Central Valley using CRAM. The aquatic features assessed included

individual vernal pools, vernal pool complexes, and depressional wetlands located on the floor of the Central Valley, as well as riverine wetlands along the Kings River and Poso Creek. A certified CRAM instructor supervised the assessment.

Resource Management and Development Plan Environmental Impact Study/ Environmental Impact Report, Newhall Land and Farming Company, Santa Clarita Valley, California, July and August 2010. Assessed the condition of reference-quality sites, as well as a number of existing compensatory mitigation sites, in the Santa Clara River watershed within the vicinity of the 12,000-acre Newhall Ranch site in the Santa Clarita Valley, California. The assessment methodology was based on a combination of three established methods (CRAM, HGM, and SAMP LLFA).

California High Speed Train Project, High Speed Rail Authority, Bakersfield to Palmdale, California, April 2011. Performed wetland delineations/jurisdictional determinations, and GIS mapping for various segments along the High Speed Rail alignments from Bakersfield to Palmdale, California.

California High Speed Train Project, High Speed Rail Authority, Fresno to Bakersfield, California, 2010. Performed wetland delineations/ jurisdictional determinations, and GIS mapping for various segments along the High Speed Rail alignments from Fresno to Bakersfield.

San Jose Creek Bikeway, City of Goleta, Goleta, California, 2009. Field crew leader and lead author for the wetland delineation/jurisdictional determination for a 0.5-acre site in Goleta Slough.

Former Hercules Gas Plant, Shell Exploration and Production Company, Gaviota, California, 2009. Field crew leader and lead author for the wetland delineation/jurisdictional determination for a 2-acre site along Cañada de la Huerta for the project’s Streambed Alteration Agreement and Section 404 Permit.

Resource Management and Development Plan Environmental Impact Study/ Environmental Impact Report, Newhall Land and Farming Company, Santa Clarita Valley, California, 2008. Assisted with the wetland delineation and mapping of jurisdictional waters within the 12,000-acre Newhall Ranch site in the Santa Clarita Valley, California. Assisted with the wetland delineation report.

Botanical Surveys and Mapping

Point Arguello Pipeline Company Repair Site, Freeport-McMoRan Oil & Gas, Gaviota, California, Spring 2015. Performed focused Gaviota tarplant (Deinandra increscens ssp. villosa) surveys for the repair and reference site. Technical reviewer for associated report.

Point Pedernales Pipeline, Freeport-McMoRan Oil & Gas, Lompoc and Vandenberg Air Force Dates, California, Spring 2014. Performed focused Vandenberg monkey flower (Mimulus fremontii var. vandenbergensis) and beach layia (Layia carnosa) surveys along 10-mile pipeline and reference locations.

Special-status Wildlife Surveys

Tidewater Goby Presence/Absence Survey, Basin E/F Tidal Basin Restoration Project, City of Santa Barbara, Santa Barbara, California, October 2010 and 2011–2012. In 2010, performed presence/absence USFWS protocol surveys for tidewater goby in Tecolotito Creek, Foxtrot Drain, and an existing tidal basin adjacent to the creek prior to construction. Medium water body protocol. Installed and monitored block nets downstream of the work area. Co-author of final report. 8.5 hours. From 2011–2012, performed post-construction presence/absence USFWS protocol surveys for tidewater goby in Tecolotito Creek and a constructed tidal basin. Lead author of final report. 24 hours.

Tidewater Goby and Fish Relocation, Santa Barbara Airport Tecolotito and Carneros Creek Relocation Project, City of Santa Barbara, Santa Barbara, California, August 2006 – November 2008. Captured and relocated tidewater gobies and other fish species from Tecolotito and Carneros Creeks. Performed initial presence/absence USFWS protocol surveys for tidewater goby in all locations prior to construction. Performed presence/absence protocol surveys for tidewater goby in all locations after construction. Medium water body protocol. Managed data collection and compilation. Included as a permitted handler on USFWS Biological Opinion 1-8-06-F-42. Assisted in authoring the final report. 145 hours.

Western Snowy Plover and California Brown Pelican Construction Monitoring, Laguna Channel Tidal Gate Repair Project, City of Santa Barbara, Santa Barbara, California, October – December 2006. Performed clearance survey prior to moving sand from near the launch area at the Santa Barbara Harbor. Monitored for impacts to the birds during construction at the tidal gate.

Habitat Restoration

Santa Barbara Airport Tidal Basin Restoration Project, City of Santa Barbara, Santa Barbara, California, 2007 – Present. Project Manager. Assisted in planning and implementing restoration for the Tidal Basin consisting of 14 acres of newly created tidally influenced habitat. Organized monitoring program consisting of point-intercept transect data collection and maintenance monitoring. Managed and analyzed resulting data. Aided with benthic macroinvertebrate sampling. Created water quality monitoring program. Lead author for annual reports detailing restoration success. Co-author of Biological Assessment. Lead author of Storm Water Pollution Prevention Plan. Currently, the restoration site has met or exceeded permit issued performance criteria.

Santa Barbara Airport Airfield Safety Projects Restoration Project, City of Santa Barbara, Santa Barbara, California, 2007–2013. Project Manager. Assisted in planning and implementing restoration for 65 acres of wetland, coastal sage scrub, and riparian habitats. Organized and implemented monitoring program consisting of point-intercept transect data collection and maintenance monitoring. Managed and analyzed resulting data. Organized native seed collection. Lead author for annual and quarterly reports detailing restoration success. Three restoration sites have been completed and met or exceeded permit issued performance criteria.

Permits

California Department of Fish and Wildlife Scientific Collecting Permit for mammals, reptiles, amphibians, vernal pool/terrestrial invertebrates, freshwater and anadromous fishes, and freshwater invertebrates #SC-10045, December 2008 – Present.

U.S. Fish and Wildlife Service Recovery Permit for Tidewater Goby (Eucyclogobius newberryi) #TE-217402-0, February 2010 – present.

California Department of Fish and Wildlife Collecting Permit for State-Designated Endangered, Threatened, or Rare Plants #2081(a)-13-35-V, April 2010 – Present.

Specialized Training

Surface Water Ambient Monitoring Program (SWAMP), field procedures and bioassessment concepts, presented by California Waterboard, April 2016

California Rapid Assessment Method (CRAM) Estuarine Module, presented by UC Davis Extension, October 2012

California Rapid Assessment Method (CRAM) Practitioner Training and Riverine Module, presented by UC Davis Extension, March 2012

Basic Wetland Delineation Training (40-hour), presented by the Wetland Training Institute, August 2008

8. Phil Mineart

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Attorneys for Applicant

State of California

Energy Resources

Conservation and Development Commission

In the Matter of: Application for Certification for the PUENTE POWER PROJECT	Docket No. 15-AFC-01 EXPERT DECLARATION OF PHILLIP MINEART IN RESPONSE TO REPORT OF DR. REVELL

I, Phillip Mineart PE, declare as follows:

1. I am employed by AECOM, which has been retained by the Applicant to conduct certain analyses associated with the proposed Puente Power Project (Project) and am duly authorized to make this declaration.

2. I earned a Bachelor of Science degree in Environmental Engineering from Humboldt State University in 1979 and a Master of Science degree in Civil Engineering from Cornell University in 1983. I have over 30 years of experience in the fields of hydrologic, hydraulic and hydrodynamic analysis, coastal engineering, erosion and sediment transport modeling, environmental restoration, risk assessments, climate change and sea level rise. A copy of my current curriculum vitae is attached to this declaration as Attachment A. Based on my education, training and experience, I am qualified to provide expert testimony as to the matters addressed herein.

3. I prepared or participated in preparing, and am knowledgeable of the contents of, the following Applicant's Exhibits:

- Applicant’s Exhibit No. 1010: Application for Certification, 4.4 Geological Hazards and Resources (Tsunami) (CEC TN #204219-11);
- Applicant’s Exhibit No. 1021: Application for Certification (AFC) Section 4.15, Water Resources (CEC TN #204219-22);
- Applicant’s Exhibit No. 1042: AFC Appendix N, Water Resources (N-2) (CEC TN #204220-14);
- Applicant’s Exhibit No. 1043: Applicant’s Responses to CEC Data Requests Set 1 (DR 41) (CEC TN #205765);
- Applicant’s Exhibit No. 1059: Applicant’s Responses to City of Oxnard Data Requests Set 2 (DR 47 – 65, 67) (CEC TN #206310);
- Applicant’s Exhibit No. 1061: Applicant's Responses to City of Oxnard Data Requests Set 2, 30-Day Extension (59, 60, and 62) (CEC TN #206533);
- Applicant’s Exhibit No. 1070: Applicant's Responses to City of Oxnard Data Requests Set 4 (DR 83 – 90, 92 - 94) (CEC TN #207179);
- Applicant’s Exhibit No. 1077: Applicant's Responses to City of Oxnard Data Requests Set 5 (DR 95 – 99) (CEC TN #210971);
- Applicant’s Exhibit No. 1086: Response to Recommended Specific Provisions in August 26, 2016 Proposed Report (CEC TN # 213624);
- Applicant’s Exhibit No. 1087: Comments on California Coastal Commission Report to California Energy Commission on AFC 15-AFC-01 - NRG Puente Power Project (CEC TN # 213625);
- Applicant’s Exhibit No. 1088: Final NRG Comment Letter to California Coastal Commission re Agenda Item F10a; Sept. 9, 2016 (CEC TN # 213626);
- Applicant’s Exhibit No. 1089: Applicant's Comments on the Preliminary Staff Assessment (CEC Log No. TN #213683);
- Applicant’s Exhibit No. 1090: Puente Power Project (P3), Project Enhancement – Outfall Removal and Beach Restoration (Section 3.2) (CEC TN #213802); and

- Applicant's Exhibit No. 1093: Applicant's Responses to City of Oxnard Data Requests Set 6 (DR 104 - 108) (CEC TN #214330).

4. I have reviewed and am knowledgeable of the contents of the following documents:

- California Energy Commission (CEC) Staff Final Staff Assessment (FSA), Part 1, Section 4.11, Soil and Water Resources (portions pertaining to coastal and riverine flooding) (CEC TN #214712);
- CEC FSA, Part 1, Appendix SW-1, Soil and Water Resources, Effects of Climate Change and Coastal Flooding on Puente (CEC TN #214712);
- CEC FSA, Part 1, Appendix SW-3, Soil and Water Resources, Estimating Flushing Times (CEC TN #214712); and
- FSA, Part 2, Section 5.2, Geology and Paleontology (portions pertaining to flooding and tsunami) (CEC TN #214713).

5. I have reviewed the Report prepared by Dr. David Revell PhD and filed by intervener City of Oxnard on January 18, 2017 (CEC TN #215427), and various supporting documents filed concurrently therewith (CEC TN #215428-1 through #215428-7) ("Revell Report").

6. Except where stated on information and belief, the facts set forth hereinare true of my own personal knowledge, and the opinions set forth herein are true and correct articulations of my opinions. If called as a witness, I could and would testify competently to the facts and opinions set forth herein.

7. Intervenors in their submitted testimony have claimed that the proposed Project has a high risk of flooding due to coastal hazards and that the dunes fronting the Mandalay Generating Station (MGS) property, which includes the Project site, could be subject to significant erosion during large storm events and, therefore, cannot be relied upon to provide protection against flooding. I have reviewed data related to coastal hazards and flood protection and believe that the intervenors have overstated the risk of flooding and potential damage to the Project, and understated the stability of the dunes and therefore the protection they can provide.

Following is a summary of my analysis, which provides a more accurate assessment of the coastal hazards and dune stability. I have also provided specific rebuttals to the analysis provided in the Revell Report (CEC TN #215427).

Flood, Sea Level Rise and Tsunami Hazards

8. Intervenors oppose the location of the Project site because of the perceived vulnerability of the Project site to flood, sea level rise ("SLR") and tsunami hazards. For the reasons set forth below, I believe the testimony of the intervenors overstates these potential risks. In addition to extensive analysis of these issues in the CEC proceedings, as reflected in the FSA, these issues were the subject of expert testimony and briefing before the California Public Utilities Commission ("CPUC") in connection with the CPUC's consideration and approval of the resource adequacy purchase agreement between NRG and Southern California Edison for the Project. Expert testimony presented in the CPUC proceedings, and relevant to the issues raised in the Revell Report, is summarized in the Reply Brief of NRG Energy Center Oxnard LLC and NRG California South LP ("CPUC Reply Brief') attached hereto as Attachment B and incorporated herein by reference.

Flooding Risk

9. The MGS property, of which the Project site is a part, is located at an elevation of between 12 and 14 feet (NAVD88). Relative to the local tidal datums, the MGS property is approximately 7-9 feet above Mean Higher High Water (MHHW) and 11-13 feet above Mean Lower Low Water (MLLW). The Project site is on the higher portion of the MGS property (~14 feet) and is, therefore, approximately 9 feet above MHHW. Compared to the local active tide gages (Santa Barbara and Santa Monica), the Project site is over 5 feet higher than the highest observed water level (8.31 feet in November 1982)[1].

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[1] MHHW is 5.31 ft NAVD88 and the highest observed water level is 7.54 ft NAVD88 at Tide Station #9411340, Santa Barbara. MHHW is 5.24 ft NAVD88 and the highest observed water level is 8.31 ft NAVD88 at Tide Station #9410840, Santa Monica. See https://tidesandcurrents.noaa.gov/map/ for data.

10. Potential sources of flooding risk for the proposed Project site are the Santa Clara River (riverine flooding) if it overtops its banks, or coastal flooding if a large storm in the Pacific Ocean overwhelmed the beach and dunes fronting the site. The entire MGS property, including the proposed Project site, is outside the FEMA 100-year floodplain from either of these potential sources, riverine or coastal flooding.

11. The Project site is located about 1.5-2.0 miles south of the mouth of the Santa Clara River and over 2.5 miles from the Victoria Avenue Bridge over the Santa Clara River. If the Santa Clara River were to overtop its banks, flood waters would need to flow overland before reaching the MGS property, and would be expected to be shallow. As shown on FEMA's Flood Insurance Rate Map (FIRM) Community Panel Numbers, No. 06111C0885E and 06111C0905E (Effective Date of January 20, 2010), a portion of the MGS property, including a very small portion of the Project site on which nothing is planned for development, is shown in the FEMA "Zone X- Other Flood Areas" (areas protected by levees from 1 percent annual chance flood, areas of 0.2 percent annual chance flood; areas of 1 percent chance flood with average depths of less than 1 foot or with drainage areas less than 1 square mile). For the MGS property, including the Project site, this flood hazard zone would be best described as an area of 0.2 percent annual chance flood, which corresponds to the 500-year floodplain, or an area of 1 percent chance flood (i.e., 100-year flood event) with average depths of less than 1 foot. More detailed analysis of the 500-year floodplain is contained in Attachment C to this declaration and incorporated herein by reference.

12. The FEMA maps show flooding near the Project site from the Santa Clara River where it breaks out of its banks near its mouth. On the FEMA maps, the base flood elevation is 10-12 feet, which is below the elevation of the flood protection berm along the north MGS property line (which is at an elevation of 17-18 ft NAVD88). Furthermore, the Edison Canal would act as a drain limiting the amount of water that could flood the site from an upland source.

13. Coastal flooding is shown on the 2010 effective FEMA maps at the MGS property as a VE zone. VE zones are defined as "areas subject to inundation by the 1-percent-

annual-chance flood event with additional hazards due to storm-induced velocity wave action." Unlike the more common AE zones, which show the depth or elevation of flood water, VE zones show the elevation of wave run-up. The effective FIRM shows a VE zone with a value of 13 feet.

14. FEMA is in the process of updating FIRMs of Ventura County. FEMA's Draft Work Map, which was included in the FSA as Soil and Water Resources Figure 7, and is the precursor to preliminary maps, shows the VE zone has increased to 20 feet. This wave run-up level at 20 feet represents the ocean still water level (water level excluding waves) of approximately 8 feet in elevation plus the level of wave run-up on the beach, not the level of flooding. If FEMA determined that a dune would be overtopped by wave run-up (e.g., dune was lower in elevation than the VE zone), FEMA would include an estimate of the depth of flooding on the back side of the dune due to the water that overtopped the dune, typically shallow flooding of a few feet (not the elevation of the VE zone). The dunes directly in front of the Project site are over 100 feet in width, and thus any future overtopping of shallow water, if it were to occur, would have to travel a significant distance prior to reaching the Project site.

Coastal Erosion

15. I disagree with the contention of the intervenors that the dunes are at high risk of failure due to erosion and, therefore, do not provide the level of protection they historically have provided.

16. I agree with the CEC Staff conclusion that the sediment discharged from the Santa Clara River comprises the majority of the shoreline sediment supply in the Project vicinity, with sand bypassing from Ventura Harbor a secondary source. I also agree with the CEC Staff conclusion in the FSA that the lack of dredging at Ventura Harbor, assuming the Santa Clara River watershed remains unchanged, would not significantly reduce the volume of sand needed to maintain the beach width at the Project site. A more detailed analysis of this issue is provided below.

17. In fact, the FSA significantly understates the extent of historic beach accretion and protection it provides. Since 1947, the beach fronting the MGS property has increased in width by more than 300 feet (see AFC Figure 4.15-7, which shows the growth in

width based on aerial photos) (Applicant's Exhibit No. 1021; CEC TN #204219-22). This estimate of width is the distance from the outfall headwall to the water line at the time of each photo. The estimate is approximate because the water level changes with the tides and season; however, all the photos, taken at different times over the decades, are consistent in showing the continual increase in beach width. In the 1950s and 1960s, a paved road ran along the beach just above the outfall headwall. The road is currently buried about 3 to 4 feet beneath the sand (based on an exploratory excavation done in 2014). As can be seen by comparing historic photos provided in Applicant's Responses to City of Oxnard Data Requests Set 2 (DR 64) (Applicant's Exhibit No. 1059; CEC TN #206310), the dunes have expanded farther towards the beach and ocean, and the old beach road is now partially covered by new dunes, indicating an increase in beach volume as well as width. The dunes' growth would appear to have been limited primarily by the outflow from the MGS outfall, rather than by erosion caused by extreme water levels or storms. This is indicated by the larger width in the dune field farther north and south from the outfall, where the outfall discharge impacts the beach less.

Specific Responses to Revell Report

18. The Revell Report (CEC TN #215427) provides information that I believe overstates the risk the proposed Project site faces from coastal hazards. I have provided my rebuttals below in the order presented in the Report.

Beach Changes Between 2009 and End of 2016 (Revell Report, p. 5)

19. The Revell Report makes several statements about the use of the 2009 LiDAR data that was used in the analysis presented in the FSA, claiming it was from a period when the beach was exceptionally wide. The 2009 data were collected in November 2009, a time when the beach may have been wider than the narrowest beaches observed in the winter (sandy beaches on the coast of California tend to be wider in the summer and narrower in the winter). To test this, the City of Oxnard collected topographic data of the beach on December 20, 2016. These data were compared to the 2009 LiDAR data and several, I believe erroneous, conclusions were drawn from the comparison. Figure 1 below is an artistic rendering of Mandalay Beach after the existing outfall is removed. The original figure is from the FSA,

which was taken from Applicant's Project Enhancement – Outfall Removal and Beach Restoration (Applicant's Exhibit No. 1090; CEC TN #213802) but the version provided in Figure 2 below is from the Revell Report.

20. The black and green arrows in the figure purport to show areas of recent or substantial erosion. As discussed below, both arrows point to "crescent" shaped areas that are formed by the discharge from MGS. The accumulation of sand on the beach during periods when the MGS is not operating causes the discharge from the outfall to veer to the south and occasionally north and landward. These "crescent" shaped areas can be impacted by storms, but the topography within these areas changes regularly due to the different flow paths followed by the discharge each time the MGS is in operation. They are easily identified in the field and aerial photographs. The landward edge of the "crescents" tends to be scarped due to the MGS discharge creating a channel within the crescent area. These "crescent" shaped areas can be identified in Figure 2. The horizontal line in Figure 2 follows the edge of the dunes/vegetation. It can be seen from following the line that the edge of the dunes follows a fairly straight line along the beach except where disturbed by the outfall. Once the outfall is removed, it is expected that the portion of the beach impacted by the outfall will take on the appearance of the areas to the north and south. The blue arrow in Figure 1 appears to be misplaced, as it points to the existing location of the outfall, sand shown there is the artist's rendering of the beach after outfall removal.

***Claims of Changes in Topography Due to Large Storm Events (Revell Report, p. 5)*.**

21. The Revell Report claims changes in topography due to large storm events. The following is a quote from the testimony

> "*The most notable changes in topography occur at the dunes directly in front of the proposed location. These dunes were heavily impacted by recent storms--most likely during the energetic El Niño of 2015/2016 and possibly during the December 11, 2015 storm event, which destroyed portions of the Ventura pier and caused extensive flood damages around Ventura and Oxnard. The area of maximum dune erosion resulted in the vertical erosion of 12 feet of sand and reduced the buffering capacity of the dunes fronting the proposed site. The beach*

during the more recent time periods (2009 and 2016) shows substantial erosion of the dunes at the back of the beach (Upper transect) in the area fronting the proposed site."

22. Plant personnel at the MGS make daily inspections of the beach and dunes in front of the facility. Furthermore, areas of substantial erosion, especially an area with 12 feet of vertical erosion, which is over twice the height of the average person), would have taken a long time to heal, possibly years. None of the claims of erosion in the above quote were observed during any inspections (*See,* Applicant's Exhibit No. 1121, Declaration of Thomas Di Ciolli).

Figure 2. Photo from FSA showing view of Puente site with an artistic rendering to show a potential post-construction removal of the existing outfall structure. The black arrow indicates recent dune erosion and the blue arrow shows area of recent wave overtopping to the access road. The green arrow shows part of the area of substantial dune erosion depictedin Figure 3.

Figure 1 from Revell Report (CEC TN #215427, Figure 2) showing Puente site with artistic rendering to potential post-construction removal of the existing outfall structure. Explanation of the arrows is provided in the text

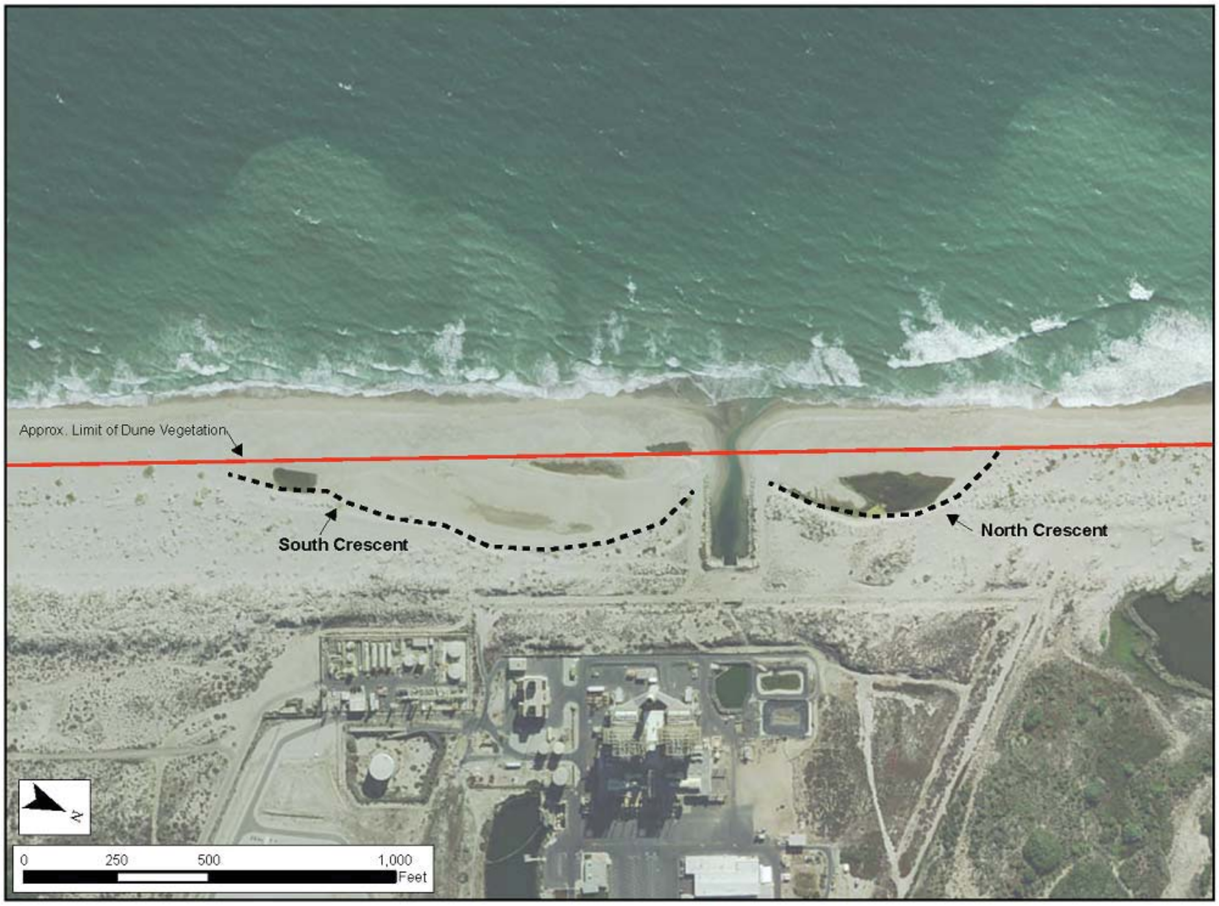

Figure 2 Aerial Photograph of Mandalay Beach Showing Edge of dune vegetation and Crescent Shaped areas Caused by MGS Discharge. North is to the right. The "Crescent" shaped areas due to the discharge are indicated by the arrows.

23. Figure 3 from the Revell Report compares the 2016 LiDAR collected by the City of Oxnard to the 2009 LiDAR used in the FSA. According to the Revell Report, *"Figure 3 in which the topographic surfaces were subtracted from each other (2016 – 2009). Areas in hot colors indicate erosion and areas of cool colors indicate accretion (Figure 3)."* It must be assumed the yellow represents areas of no change since areas inland and on the plant site are yellow and are not expected to change elevation. The major take-a-way from the comparison is that the beach fronting Mandalay between 2009 and 2016 either stayed the same (yellow color) or accreted (blue color). There is a small area on the edge of the northern crescent that shows erosion, likely due to failure of the scarp created by the MGS outflow or possibly

undercut by wave runup. Scarps on sandy beaches tend to be unstable, so it is not surprising to see some changes along them.

24. The conclusion in the Revell Report that the present beach condition is much less protective of the dunes fronting the proposed Project site than assumed in the 2009 data and relied upon for hazard modeling in the FSA is unsupported by the data presented in the Revell Report and observations of the dunes made on a regular basis by MGS plant personnel.

Historic Beach Variability (Revell Report, p. 8)

25. I agree that beach widths can be variable over seasons and years. Beacon Line 32 provided as Figure 5 in the Revell Report is located just south of the mouth of the Santa Clara River where the largest variability is expected given that it is closest to the sediment sources (Santa Clara River and Ventura Harbor). Beacon Line 33 appears to be located at McGrath Lake near the proposed Project site, and lines 34, 35 and 36 are located on Oxnard Shores beach. Results for Beacon Line 33 are similar to the results at Beacon Line 32 as described in the Revell Report in that the change between years is not continuously positive or negative and there are large changes between some years. This profile is likely influenced by McGrath Lake. However, lines 34-36, which are located on a sandy beach similar to Mandalay Beach, show an almost continuous increase in beach width from 1987 to 2007 (though not uniform in magnitude between measurements) of between 250 feet at line 34 (closest to Mandalay Beach) and 100 feet at lines 35 and 36. The locations of the Beacon Lines were estimated from Figure 3.1 in Barnard (2009)[2] and the shape of the profiles from figures in Appendix A of the same report.

26. The Revell Report states at page 8 that sand had been largely trapped on the beaches in front of the site due to the lack of dredging at the Channel Islands Harbor. Dredging records provided in Applicant's Responses to City of Oxnard Data Request Set 2 (DR 56) (Applicant's Exhibit No. 1059; CEC TN #206310), Applicant's Responses to City of Oxnard

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[2] Barnard et al 2009., Coastal processes study of Santa Barbara and Ventura Counties, CA: U.S. Geological

Survey Open-File Report 2009-1029, http://pubs.usgs.gov/of/2009/1029/

Data Request Set 4 (DR 83) (Applicant's Exhibit No. 1070; CEC TN #207179 and Applicant's Responses to City of Oxnard Data Request Set 5 (DR 95) (Applicant's Exhibit No. 1077; CEC TN #210971) show that Channel Islands Harbor was dredged 12 times between 1987 and 2007, or about every other year. The amount dredged was about equal to the long-term average rate of dredging. The contention that the beach growth was partially due to lack of dredging at Channel Islands Harbor is unsubstantiated by the data.

Topographic Variations in front of MGS and Project Site (Revell Report, p. 9)

27. The Revell Report developed three beach cross-sections from topographic data collected in 1997, 1998, 2009 and 2016 and compared them to each other to estimate beach erosion. The upper section is located near the northern boundary of the MGS property, the middle section along the northern edge of the outfall structure, and the lower section through the middle of the southern crescent described above (see Figure 2 for location of crescent).

28. Table 1 in the Revell Report provides a geomorphic summary of the beach profiles. The analysis shows that the beach grew from about 350 to 390 feet wide in 1997 to about 550 to 585 feet wide in 2009 at the upper and middle sections (about 200 feet increase in width). There was a small decrease of 25 to 50 feet between 2009 and 2016. This decrease is about 10% of the beach width. This is likely within measurement and analysis error though it is also possible that that the beach has narrowed slightly. Even on an accreting beach there will be years or seasons where the beach narrows. For the lower section, the Revell Report shows that the beach narrowed from 415 feet wide in 1997 to 200 feet wide in 2009 and 2016, a decrease of 200 feet. The results indicate that north of the outfall the beach is presently over 300 feet wider than it is south of the outfall. A review of aerial photographs or a visit to the site will show that the beach is fairly uniform in width along the entire length of the MGS property (see Figure 2). The 200 feet width calculated for 2009 and 2016 for the lower section is likely due to locating the section in the "crescent" area formed by the MGS discharge. When the outfall is removed, the "crescent" should fill in with sediment.

29. Table 1 in the Revell Report also lists beach slopes for each beach profile. For the upper and lower sections the slopes generally got shallower over time due to the growth

of the beach. The lower section got steeper with a predicted slope of 18% in 2016, which is very steep for a sandy beach. As with the width, the large slope calculated for the lower section is likely due to placing the section in the crescent area created by the MGS discharge, an area unrepresentative of beach morphology. The upper and middle sections may be more representative, and both indicate an accreting beach with shallow slopes.

30. Lastly, the Revell Report compares the outfall structure to the groin field at Pierpoint Bay (p. 11) and claims that the outfall acts as a groin capturing sediment in front of the MGS property. If this was true, removal of the outfall structure would result in the structure no longer retaining sediment, and the beach could narrow and the likelihood of dune erosion could increase. A groin is a structure placed perpendicular to a beach designed to intercept the long shore transport of sediment. It is often used to prevent the movement of sand down the beach to widen or prevent narrowing of a beach. To be effective, a groin needs to be placed in the surf zone and portions of the beach regularly exposed to wave run-up (i.e., wetted area of beach). This is where most of the longshore sediment transport occurs. A look at the Pierpont groin field on Google Earth will show that the groins are low on the beach (below MHHW and within the area subject to the tides). The MGS outfall is out of the surf zone and rarely subject to wave run-up and, therefore, too high up on the beach to act as an effective groin (the outfall is above MHHW). I disagree with the Revell Report that removal the outfall would have a significant negative effect on the movement of sand along the beach.

Sediment Supply

31. The Revell Report contends that the FSA overestimates the sediment contribution of the Santa Clara River, and underestimates the importance of dredging Ventura and Channel islands Harbors. The Revell Report also disagrees with the FSA assessment regarding the particle size of sediment that should be included in the analysis. Regarding the selection of correct particle size for calculating sediment load that can remain on the beach, it is clear from the fact that Mandalay Beach has increased in size over the decades that the supply of sediment is more than sufficient to maintain the beach irrespective of which particle size is

responsible. In general I agree with the staff assessment of sediment supply; however, I would like to point out the following additional information.

32. The Revell Report appears to acknowledge the history of beach accretion fronting the MGS property, and I agree that sand bypassing from the Ventura Harbor contributes to such accretion, however, I believe the Report gives undue weight to concerns regarding possible future variability of dredging and sand bypassing. If Ventura Harbor dredging ceased, a bypass bar would likely form and sand transport past the harbor would eventually return to near pre-harbor construction conditions. The sand trap updrift of Ventura Harbor usually fills within a year or two, after which sand bypasses the trap and deposits in the channel and harbor requiring annual dredging to keep the harbor open (if the sand didn't bypass the trap, the channel would not need to be dredged). Last year (2015-2016) resulted in a large amount of sediment bypassing the sand trap updrift of the Ventura Harbor and depositing into the Ventura Harbor inlet. The January 21, 2016 Ventura County Star newspaper reported that about 900,000 cubic yards of material was deposited at Ventura Harbor, filling the sand trap and overflowing into the inlet channel to the harbor. The newspaper reported that the harbor entrance normally has a depth of 40 feet but was down to 14 feet last year, and that the harbor entrance normally has a navigable area about 300 feet wide but was down to about 40 feet last winter. The harbor was dredged last winter, but if dredging did not occur, the harbor would likely become completely blocked within a few years. After that, most of the sediment that normally collected in the harbor and was dredged and bypassed to the down drift beaches would naturally bypass the harbor and continue south as it did before harbor construction. Thus, if dredging was completely and permanently discontinued at Ventura Harbor, which is unlikely, there would be only a short-term impact on the transport of sand down drift. Implicit in Revell's assumption on the importance of dredging Ventura Harbor is that if the Harbor is not dredged the sand disappears from the system and is not available to the down drift beaches. I disagree with this implicit assumption for the reasons discussed above. Whether the harbor is dredged or not, eventually most of the sand transported towards Ventura Harbor would be transport towards Mandalay Beach either naturally or by dredging. In addition, though the Corps of Engineers' budget for dredging commercial harbors

in the future is unknown, the implied assumption that Ventura City and County would abandon Ventura Harbor, and all its economic activity and hundreds of million dollar plus homes, is a remote possibility and I disagree that it needs to be considered as a reasonable possibility as implied by the Revell Report.

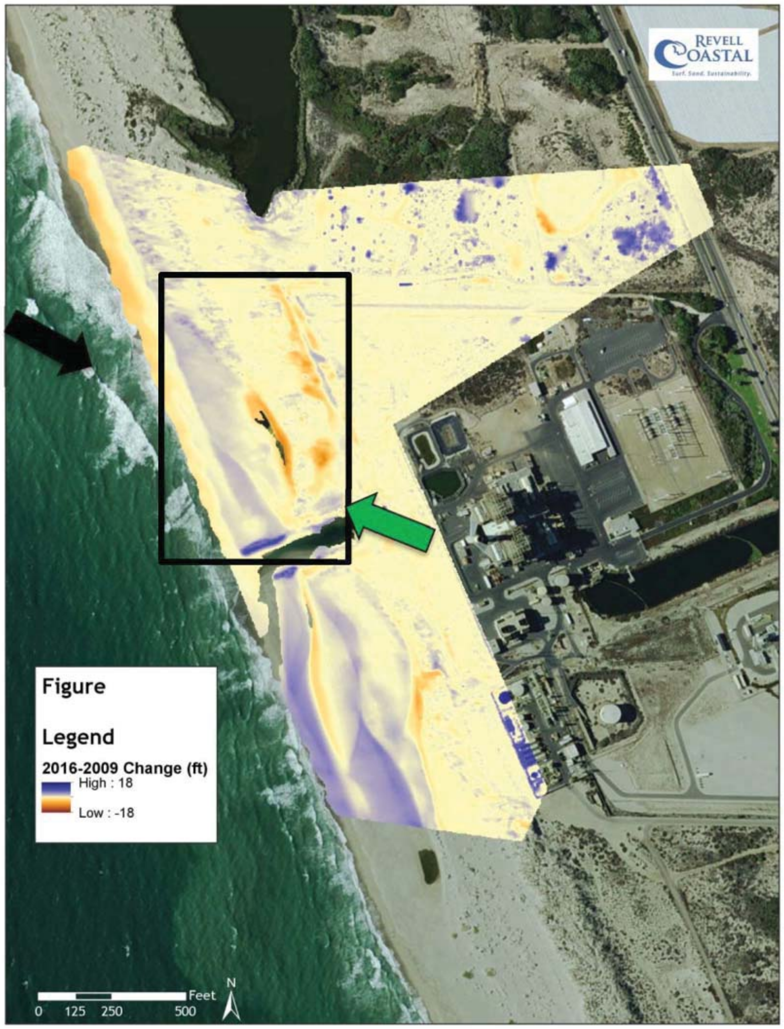

Figure 3. Topographic changes between 2016 and the 2009 LIDAR. The hot colors indicate erosion and the cool colors indicate accretion. The black arrow is the approximate view angle for the FSA cover image and the black box highlights the area of greatest change in front of the proposed Puente project. The green arrow approximates the dune identified with the same arrow in Figure 2.

Figure 3. Comparison between 2009 LiDAR used in the FSA and the 2016 LiDAR collected by the City of Oxnard. The hot colors indicate erosion and the cool colors indicate accretion. Significance of the arrows and box are provided in the Revell Report. (Figure is Figure 3 from Revell Report).

33. The Revell Report states that the FSA was deficient in not discussing the dredging at Channel Island Harbor. It claims that the observed beach widening is at least partially explained by the "substantially less frequent dredging at Channel Island Harbor in the last decade". Channel Island Harbor was dredged every other year since 1974 except for 1997-1999, during which three years in a row were dredged (See Applicant's Responses to City of Oxnard Data Request Set 2 (DR 56) (TN #206310), Applicant's Responses to City of Oxnard Data Request Set 4 (DR 83) (Applicant's Exhibit No. 1070; CEC TN #207179) and Applicant's Responses to City of Oxnard Data Request Set 5 (DR 95) (Applicant's Exhibit No. 1077; CEC TN #210971)). Except for 2013, dredging over the last decade at Channel Island Harbor has not been very different from historic dredging rates. In fact 2015 and 2009 were two of the highest rates of dredging since 1972.

34. The Revell Report claims that rising seas and increased coastal hazards will cause the dunes to migrate inland onto the Project site (p. 13). The dunes fronting the MGS property are vegetated and not as mobile as "sand" dunes which migrate due to wind blowing sand off the dune in the inland direction. Vegetation tends to stabilize dunes and prevent their migration. As long as the dunes remain vegetated they should remain stable and not migrate.

Implications of Topographic Changes on FEMA Preliminary Coastal Flood Maps

35. The Revell Report claims that the preliminary FEMA flood maps underestimate the coastal hazards at the MGS property. Table 2 in the Revell Report, provides alternative calculations for wave run-up elevations that he claims are representative of the VE zone fronting MGS. The FEMA value shown on the preliminary map is 20 feet. The calculation of wave run-up is very sensitive to the beach slope used in the calculation. FEMA used a value of 5%. Based on the 2009 Lidar data, slopes of 3% to 5% were measured and provided in Applicant's Responses to City of Oxnard Data Request Set 4 (DR 87) (Applicant's Exhibit No. 1070; CEC TN #207179). These are consistent with FEMA's analysis and typical for sandy beaches. The Revell Report presents results for slopes up to18%. He observed the 18%slope on his lower section from his 2016 data. As discussed above under *Beach Changes between 2009*

and End of 2016 this section was placed in the area that receives discharge from MGS and so has channels cut into the beach from the discharge and is not representative of beach slopes. The beach slopes measured at the other two sections are 5% to 6% more similar to what I measured from the 2009 LiDAR and what was used by FEMA. In this same section, he reports that substantive dune erosion occurred during the January 1983 event (the largest event on record) based on his review of a 1984 aerial photograph (Figure 7 in his report). The aerial photograph is low resolution and does not contain sufficient detail to identify areas of dune erosion. It appears from his statement that he may have interpreted the white areas on the dune face as areas of erosion rather than areas of no vegetation or vegetation too sparse to show up on the photograph.

FEMA and Sea Level Rise

36. The Revell Report calculated the transgression[3] of the beach and dune profile based on different levels of SLR from present to the year 2100. Although he did not specify his method it appears from the results that he used the "Bruun" rule for calculating shoreline retreat. The Bruun rule is a simple method for calculating shoreline retreat. According to the Bruun rule the amount of shoreline retreat is simply the amount of sea level rise divided by the beach slope. For example if SLR was 1 foot and the beach slope was 1% (1/100) the shoreline is predicted to retreat 100 feet. Note that the amount of shoreline retreat is completely dependent upon the selected slope of the beach. In the above example, if the beach slope was 10%, instead of 1%, the shoreline would be predicted to retreat only 10 feet. In Table 3 of the Revell Report, Dr. Revell provides estimates of the amount of transgression assuming a beach slope of 1/75 or 1.33%. With 2 feet of SLR this results in a transgression of 150 feet. Note that in Table 1 of the Revell Report the smallest slope he reports for Mandalay beach is 4% and the highest 18%. With 2 feet of SLR and a 4% slope the transgression of the profile would be 50 ft not 150 ft, as he reports in his Table 3, and using 18% , the highest value in Revell

[3] The transgression of the dune is the migration of the dune inland, usually in the direction of the prevailing wind, that buries the existing topography with sand. It is driven by aeolian sand transport. Beach transgression is the movement of the beach profile inland.

Report Table 1, the transgression would only be 18 feet. The slope Dr Revell uses in his calculations for transgression do not represent the slopes on Mandalay Beach even according to the data in his Report (See his Table 1).

37. The Bruun rule has been used for decades to estimate shoreline retreat due to SLR. However, it suffers from several deficiencies that make it unreliable as a method for shoreline retreat (see Copper and Pilkey 2004 for example)[4]. Three important assumptions required to use the Bruun Rule that invalidate its use on Mandalay Beach are:

- **No net longshore transport** – Mandalay Beach has grown by several hundred feet in the last few decades. In Table 1 in the Revell Report, he shows a growth of 300 feet in beach width between 1997 and 2009 on two of his transects, and then a small decrease in width by 2016. This indicates a system that has a significant amount of net longshore transport. The Bruun rule only allows cross-shore transport since it makes the simple assumpion that sand on the upper part of the beach is transported to the lower part keeping the same profile.
- **SLR can only cause shoreline retreat** – Using the Bruun rule, shorelines can only retreat. This is obviously not true on Mandalay Beach, which has grown in size since construction of the MGS.
- **Implied by the rule - the slope and characteristics of the upland area or back shore doesn't affect the retreat –** Whether the dunes exist or not, are vegetated or not, the Bruun rule gives the same amount of shoreline retreat.

38. For these reasons, and others, using the Bruun rule for shoreline retreat at Mandalay Beach is incorrect. Figure 9 in the Revell Report shows that the VE zone for the MGS facility will be located at the eastern edge of the detention basins with 2 feet of SLR, yet 2 feet of SLR does not even bring MHHW near the toe of the dunes and barely brings it to the edge of the outfall structure.

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[4] Cooper, J, Andres and Orrin H. Pilkey. 2004. Sea-level rise and shoreline retreat: time to abandon the Bruun Rule. Global and Planetary Change. Vol. 43. PP 157-171.

Coastal Hazard and Sea Level Rise Modeling

39. The Revell Report provided comments on the use of the USGS COSMOS 3.0 model for hazards analysis (starting on page 22). He objected to the use of the USGS model and described why he believes The Nature Conservancy Model is preferable. In general, I agree with the CEC Staff's discussion in the FSA, but have some additional comments.

40. The Coastal Resilience Ventura Coastal Hazard Mapping report (The Nature Conservancy Model or TNC model) is a planning level analysis. From the reports introduction "The Nature Conservancy is leading Coastal Resilience Ventura – a partnership to provide science and decision-support tools to aid conservation and planning projects and policymaking to address conditions brought about by climate change. The primary goals of Coastal Resilience Ventura are assessing the vulnerabilities of human and natural resources, and identifying solutions that help nature help people." The report is a planning level document. Though the report uses reasonable scientific methods to derive its estimates of coastal hazards its mapping isn't detailed enough for site studies and its scenario selection is designed to identify areas that could be impacted by climate change coastal hazards not areas that are necessarily impacted. In fact on page 8 of the document states: "This information is intended to be used for planning purposes only. Site-specific evaluations may be needed to confirm/verify information presented in these data."

41. The model is inaccurate and flawed as applied to the Project site. The model predicted that an El Nino-type storm event, such as the one that occurred in January 1983, would flood the entire Project site under current conditions, but that prediction is contrary to what actually happened. The January 1983 El Nino storm and other large storm events have occurred in the past, and the resulting waves and storm surges have had no impact on the MGS site- there was no flooding and no impact to MGS operations. Since the 1983 event, the beach fronting the MGS property has accreted and is now wider than it was in 1983. In addition, foredunes have formed and stabilized farther out towards the ocean. Thus, under "current conditions," the Project site is not more vulnerable to coastal hazards than it was in 1983, but is actually less vulnerable. Under current conditions, the Project site is protected by a beach that is

300 feet wide, with dunes that are 20 to 30 feet high. If the same event occurred today, the waves would break onto a wider beach and would need to erode the newly formed foredunes before impacting the main dunes protecting the Project site. Given that no damage occurred in 1983, it is unlikely that any damage would occur under current conditions. (See, CPUC Reply Brief, pp. 10-13). In regard to SLR, for historical perspective, during the period of 1947-2016, SLR has been 0.004 foot per year (1.34 millimeters per year (mm/yr)), as measured at the Santa Monica gage. This amounts to about 3 inches since construction of the original MGS power plant approximately 60 years ago. Although the historical rate of SLR is less than the predicted future rate, the fact that the beach has grown in width notwithstanding SLR indicates a very stable beach. The 2013 Coastal Resilience Study (specifically, Figure 16 in that report) shows that the sediment yield from the Santa Clara and Ventura Rivers should remain about the same as the historical yield until about 2050. Thus, the existing data indicate that loss of beach is unlikely to occur over the life of the Project, and even under the most conservatives analysis, the width of the beach fronting the MGS property would continue to be over 200 feet wide.

Tsunami Flooding on the MGS Beach

42. Studies of distant earthquakes (teletsunamis) indicate that the Project site is unlikely to be in the inundation zone for any reasonable return period event. Studies of tsunamis generated by local earthquakes indicate that the site is unlikely to be in an inundation zone for "frequent" events (events with return periods of 1,000 to 1,500 years or less). Studies that used conservative assumptions indicate that the Project site might be in an inundation zone for less frequent events, e.g., 2,500-year return period; however, the predicted water level is lower than the top of the dunes. Analysis of return periods for various tsunami sources indicate return periods of between 800 and 10,000 years. In all cases, the maximum projected wave height is well below the top of the existing dunes that protect the Project site.

Regarding the Goleta Landslide Scenario (p. 25 in Revell Report)

43. With recurrence times that are at least an order of magnitude longer (30,000-50,000 yr vs. 2500 yr) than those used in performance based engineering, the probability for Goleta landslides is well beyond the probability levels used in engineering practice (including

seismic hazard assessments), and it would therefore be wholly inconsistent to use these numbers for planning/design purposes. This scenario was included in the CGS tsunami inundation maps, but these are only used for evacuation planning purposes, and not for building purposes: "These maps were prepared to assist cities and counties in identifying their tsunami hazard. They are intended for local jurisdictional, coastal evacuation planning uses only (CGS)"

44. In addition, using worst-case sea-level variations on top of what is already a very low probability scenario only leads to an unacceptable compounding of conservatism.

Regarding Earthquake Activity on the Ventura Pitas-Point Fault(p 26 in Revell Report)

45. This fault is included in the standard seismic model for California (UCERF3) and the shaking hazard is presumably considered in the appropriate section, albeit at smaller maximum magnitudes than proposed in the Ryan paper. For seismic shaking purposes, that increase in magnitude may not be as significant since ground motions tend to saturate at higher magnitude levels.

46. In any case, the activity rate of the Ventura Pitas-Point is very much a subject of scientific discussion, and Ryan et al's model is currently not consistent with the seismic hazard models in current use by the USGS or the State of California.

47. Their tsunami models are not meant for quantitative hazard analysis, as stated in their conclusions. Also, the Ryan distribution of amplitudes along the Oxnard coasts are strongly governed by local bathymetric circumstances, and at the site they only reach 14ft. They write: "The more unexpected large amplitudes to the east result from two main effects: strong eastward refraction of the south- ward directed tsunami wavetrain as the waves encounter deeper water to the south in the Santa Barbara Channel (Ryan Figure 1), and focusing of the waves guided by bathymetry (e.g., intersection of slower nearshore waves with faster deepwater waves in the channel)."

48. This means that observed amplitude patterns are not random, but determined by local bathymetry. It is therefore not correct to use the maximum amplitudes along the entire Oxnard coastline as a representative measure of the tsunami amplitudes at the site. The

largest amplitudes that the Revell Report is referring to occur located more than 5 km to the south of the site.

49. I hereby sponsor this declaration into evidence in these proceedings as Applicant's Exhibit No. 1128.

Executed on January 24, 2017, at San Francisco.

I declare under penalty of perjury of the laws of the State of California that the foregoing is true and correct.

Phillip Mineart

ATTACHMENT C

500-year Flood Analysis

The P3 project site (site) is located within the existing Mandalay Generating Station (MGS) property west of Harbor Blvd and north of Mandalay County Park in Oxnard, CA (see Figure Error! No text of specified style in document.**-1**). The site is located near the upstream end of the Edison Canal, which drains south to Channel Islands Harbor. The site is approximately 9,000 feet south-southeast of the mouth of the Santa Clara River and 1,000 feet south of the overflow to the Pacific Ocean of the Santa Clara River breakout (the southern end of McGrath Lake). A small levee separates the site from the McGrath Lake area, dunes separate the site from the ocean, and no levee separates the site from Edison Canal.

Current FEMA Flood Insurance Rate Maps (FIRMs) show that a portion of the site is within a shaded Zone X. This study is being performed, in part, to support a request for a Letter of Map Revision (LOMR) from FEMA based on correcting the existing map. No changes are being proposed to the existing hydrology or hydraulic models. Hydraulic modeling described in this study was only performed to provide information on the extent of 500-year flooding from potential sources in the vicinity of the P3 project site.

1.1 Existing Topography of the Site

Topographic data covering the MGS property were obtained from a survey performed in March 2011 (Saddleback Surveys, 2011). Topographic data covering areas beyond the limits of the MGS property were obtained from the California Coastal Conservancy Coastal LiDAR Project: Hydro-flattened Bare Earth DEM[5]. This LiDAR, with 1 meter grid spacing, is a survey of coastal California extending approximately 3 miles inland in the vicinity of the site, and the survey data was collected between October 2009 and August 2011. Elevations from the LiDAR were spot-checked in the vicinity of the MGS property and were found to be in agreement within a few tenths of a foot of survey data obtained for the site (Saddleback Surveys, 2011).

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[5] Available at: https://coast.noaa.gov/dataviewer

Typical elevations within the P3 site are approximately 14.8 feet. Elevations within the overall MGS property range from approximately 11.5 to 13.5 feet (excluding the P3 site, ponds, and berms). The berm along the northern MGS property boundary, which protects the site from flooding around McGrath Lake, ranges from approximately 17.5 to 18.7 feet. The dune along the western boundary, which protects the site from coastal flooding and wave run-up, ranges from approximately 22.3 to 33.5 feet. Elevations along the top of bank of Edison Canal range from approximately 11.5 to 13.0 feet, similar to the elevations of the MGS property.

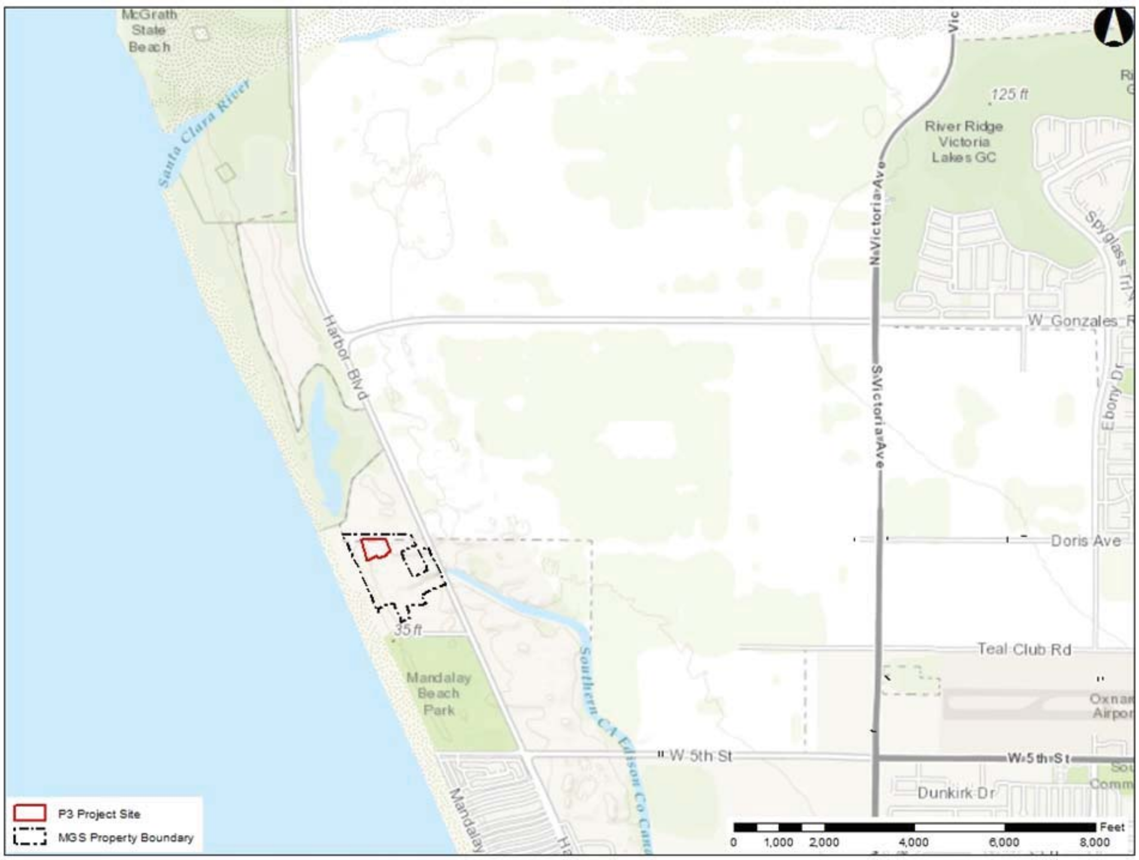

Figure Error! No text of specified style in document.**-1 Vicinity Map**

1.2 Existing FEMA Models and Studies

The current Flood Insurance Study (FIS) prepared by FEMA for Ventura County was revised January 7, 2015. The current FEMA FIRMs covering the site are dated January 20, 2010.

The 36-acre MGS property is situated in both the shaded and unshaded "Zone X" areas, as shown on FIRM Community Panel Numbers, No. 06111C0885E and 06111C0905E (Effective Date of January 20, 2010). The southern portions of both the MGS property and the site are in “Zone X – Other Flood Areas” (shaded; areas protected by levees from 1 percent annual chance flood, areas of 0.2 percent annual chance flood; areas of 1 percent chance flood with average depths of less than 1 foot or with drainage areas less than 1 square mile). The remaining portions of the MGS property and the site are in “Zone X - Other Areas” (unshaded; areas determined to be outside the 0.2 percent annual chance floodplain) (FEMA, 2010). GIS layers of the zones shown on the 2010 effective FIRMs were obtained from FEMA. See **Figure** Error! No text of specified style in document.**-2**.

Figure Error! No text of specified style in document.**-2 FEMA Flood Zones**

The available FEMA documentation for the mapping shown on the two FEMA panels was reviewed; however, detailed information to support the mapping is not available. The floodplain boundaries were compared to 2011 LiDAR, a USGS topographic map from the 1970s and the topography from 1956, pre-project construction. The floodplain boundary does not correspond to any contours on any of the maps, i.e., the floodplain boundaries do not correspond to existing or possibly historic topography. After reviewing the floodplain topography, it is not clear from the FEMA map why the flood zones are shown as they are. The Zone X (shaded) area appears to start upgradient in a residential area of Oxnard and extends southwest to the Edison Canal; it then continues along portions of the Edison Canal, including at the MGS property, with no obvious source of the flooding.

Potential sources could include the Santa Clara River overflowing its banks and flowing south to the MGS site via the Santa Clara River Breakout, but that is not what the FEMA map appears to show. If the mapped 0.2% annual chance (500-year) flooding was coming from the Santa Clara River Breakout, it would have to flow south and then east past the dune system, which does not seem likely due to the high elevations of the dunes. Other potential sources could include the Edison Canal backwatering in the upstream direction onto the MGS property due to flood flows entering downstream or from coastal flooding. However, still water flood levels in the coastal study are not high enough to overtop the banks of the Edison Canal. Inflows to the Edison Canal in the vicinity include the Doris Avenue Drain and West 5th Street Drain. The FEMA FIS states that the Doris Avenue Drain has sufficient capacity for the 1%-annual-chance flood but is subject to shallow flooding during a 0.2%-annual-chance flood. It seems likely that the shaded Zone X is mapped at the project site based on shallow 500-year flooding from the drains. The drain flows were analyzed to determine if they were possible sources of the flooding (see Section 2).

1.2.1 Older FEMA Work Maps

After submitting a data request to FEMA, AECOM obtained PDF files containing scans of various FIRM Work Maps relating to the FEMA floodplains for the City of Oxnard, CA. They were undated. These are the maps presumably used to develop the prior FEMA floodplain maps.

The existing FIRM panels generally follow the floodplain designations found on the older Work Maps with some slight variations. On the older Work Maps, the entire P3 site is identified as being in Zone C[6], an area outside of the 500-year floodplain. **Figure** Error! No text of specified style in document.**-3** shows an old FIRM Work Map (with the P3 site in Zone C) and **Figure** Error! No text of specified style in document.**-4** shows the old Work Map for the Flood Boundary and Floodway Map (FBFM) compared with the effective FEMA flood zones. The old FBFM has the 500-year floodplain boundaries labeled, which implies that the current shaded Zone X is for 500-year flooding. The zone boundaries have been modified on the newer maps putting the southern part of the P3 site into Zone X (shaded), which is a slight extension of the neighboring Zone B found on the older map. It appears that the area was revised to include the end of the Edison Canal with the boundary extending to the north of the end of the canal. It is possible that the flood-carrying capacity of the Edison Canal was not included since the maps show flooding going over the canal from east to west to connect the floodplain to the ocean.

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[6] Note on FEMA floodplain designations: FEMA has simplified its floodplain designations over the decades. On the existing maps FEMA uses an "A" designation to show areas that are within a 100-year floodplain. There are various types of "A" zones. V zones are areas of coastal flooding. X zones are areas of low hazard flooding. Shaded X zones are areas between the 100-year and 500-year floodplains, and unshaded areas are outside the 500-year floodplain. On older maps, B zones and C zones are also shown. B zones are similar to shaded X zones and C zones are similar to unshaded X zones, generally outside the 500-year floodplain but may have ponding or local drainage issues.

The old FEMA maps indicate that the flooding is likely from the Oxnard West Drain and the Doris Avenue Drain. The extent to which these drains would still cause the same flooding is unknown. The Doris Avenue Drain is the closest to the MGS property. It empties into the Edison Canal about 3,500 feet downstream of the MGS property.

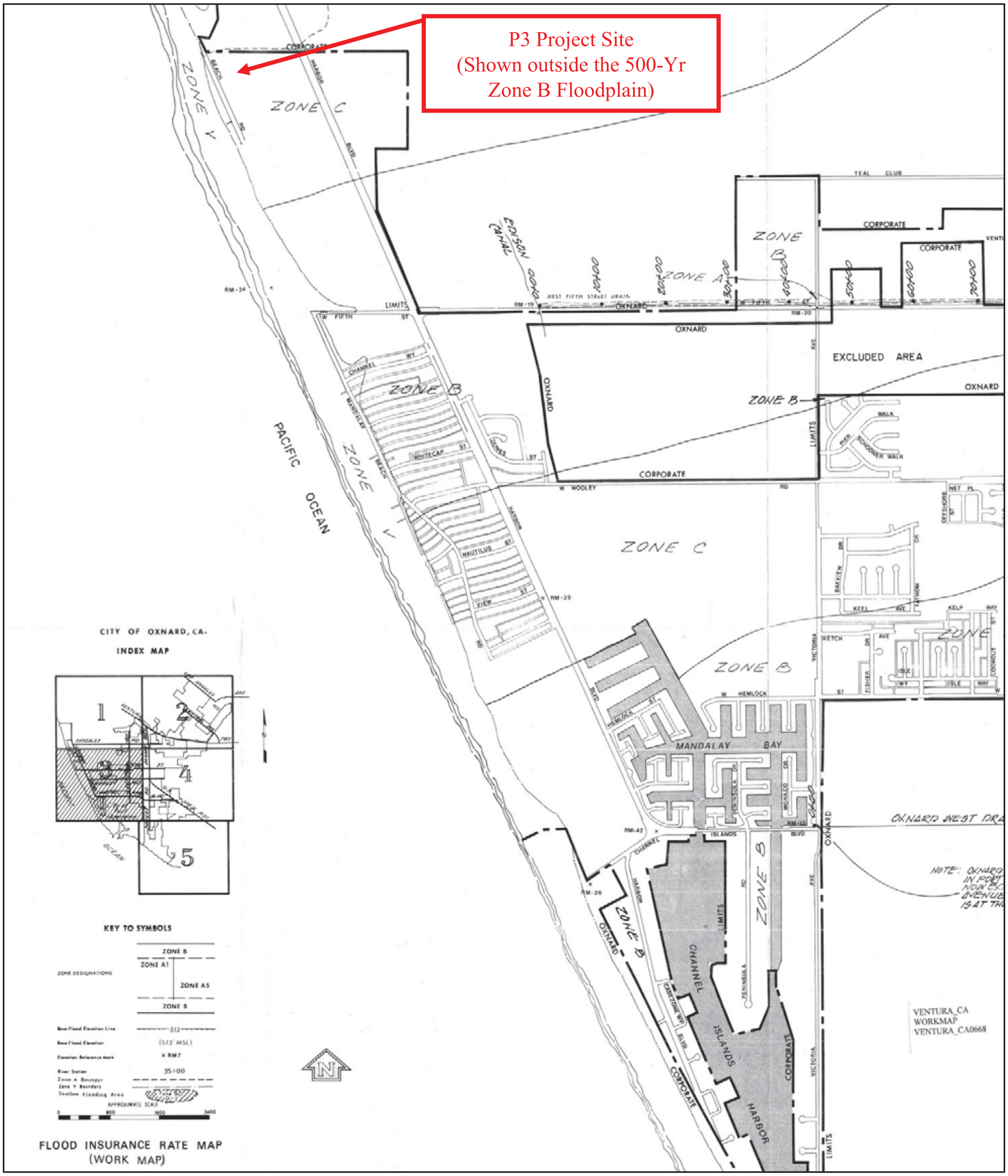
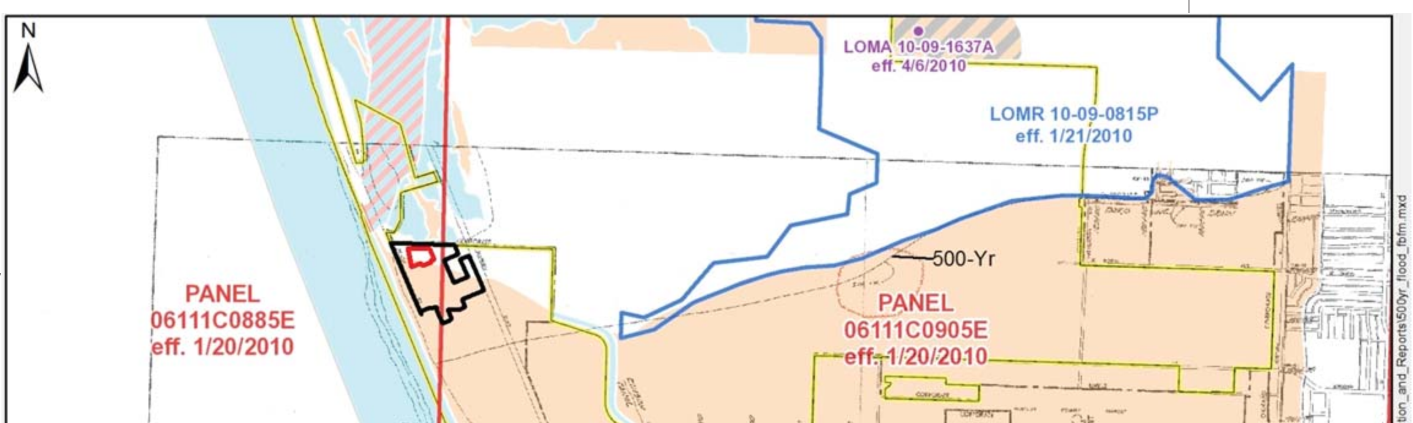


Figure Error! No text of specified style in document.**-3 Old FIRM Work Map (provided by FEMA, undated)**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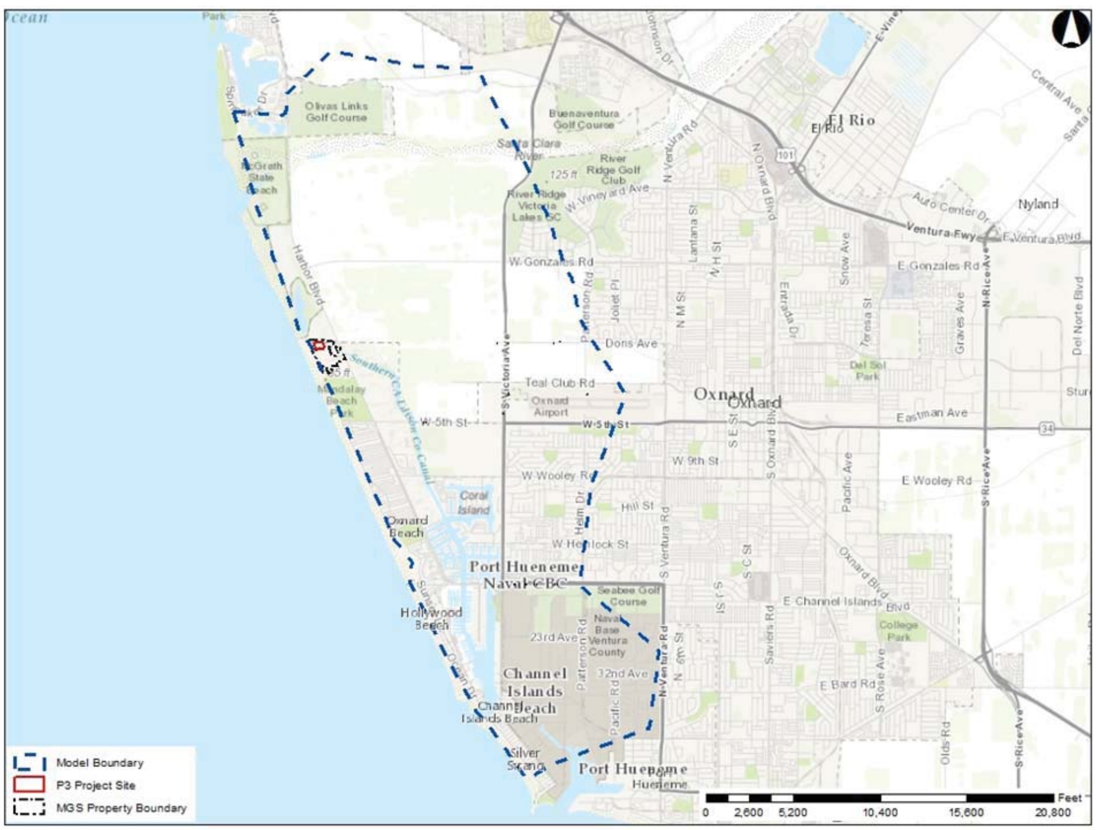
Zones Shown

2. Hydrodynamic Modeling of 500-Year Flood

To further understand the potential flooding on the P3 site caused by the 0.2% chance annual flood, a two-dimensional (2D) hydrodynamic model of the site and surrounding drainages was developed in HEC-RAS (version 5.0.3).

2.1 Model Study Area and Setup

Since flooding at the site could potentially be caused by one or more sources, the model study area was set up to capture the drainages in the surrounding vicinity of the site. The model extends from north of right bank of the Santa Clara River to south of the mouth of Channel Islands Harbor, west to the dune line along the coast, and inland approximately 2-3 miles (see **Figure** Error! No text of specified style in document.**-5**). This area captures the lower Santa Clara River, Edison Canal, Doris Avenue Drain, West 5th Street Drain, and lower Oxnard West Drain. The effective FIRM and the preliminary maps show that the site is not within a coastal



flood zone.

Figure Error! No text of specified style in document.**-5 Model Study Area**

Using the NOAA Coastal LiDAR merged with bathymetry data for the Edison Canal and Channel Islands Harbor, a model mesh was generated for the study area on a 30-meter spacing. Grid faces were enforced along breaklines such as canal inverts and tops of bank. Cell sizes were adjusted to 10-meter spacing along breaklines. Additional grid cells were added on a manual basis for specific areas of interest.

Road crossings over the three drains that showed in the LiDAR data were edited out using canal cross-sections upstream and downstream of the crossings to provide a continuous flow path in the modeling surface. Numerous other road crossings exist in the LiDAR data over tributary ditches to the three drains. These other crossings were not edited out of the model.

2.2 Hydrology and Boundary Conditions

Boundary conditions for the model describe the flows that drain into the study area and the controls that govern how they are released from the study area. Upstream boundary conditions are represented by flow hydrographs, and downstream boundary conditions are represented by the tailwater conditions, or stage hydrographs.

2.2.1 Upstream Boundary Conditions

Flows in the lower Santa Clara River, Doris Avenue Drain, West 5th Street Drain, and lower Oxnard West Drain were input to the model as hydrographs as upstream boundary conditions (see **Table** Error! No text of specified style in document.**-1**). The flows for the Santa Clara River are the flows used in the FIS for "Santa Clara R at Mouth."

The FIS provides flows for the Doris Avenue Drain and the Oxnard West Drain. Flows in the drains are based on flows used in the FIS for "Doris Avenue Drain." The flows in the drains were calculated based on watershed area and the runoff density calculated using the information in the FIS. In the FIS, Doris Avenue Drain has a 500-year flow of 750 cfs and a drainage area of 0.4 square miles; this equates to a runoff density of approximately 3 cfs/acre. The 500-year flow in the FIS for the Oxnard West Drain at the Edison Canal is 5,850 cfs for a corresponding drainage area of 4.9 square miles, which equates to approximately 2 cfs/acre. The runoff density is approximately the same for upstream locations on the Oxnard West Drain. Since the runoff density for the Doris Avenue Drain was higher than the Oxnard West Drain, it was applied to all areas draining to the Edison Canal. Watersheds for the drains were delineated in GIS based on topography and the locations of ditches and drains.

The watershed size for the entire Doris Avenue Drain is approximately 3.3 square-miles. Presumably, the 750 cfs flow is entering the very upstream end of Doris Drain because it only corresponds to a 0.4 square-mile drainage. The land use in the upper watershed of Doris Avenue Drain is mostly Developed, Medium Density according to the National Land Cover Database 2011. This level of development is consistent with the upper watershed of West 5th Street Drain and the entire Oxnard West Drain watershed. Large areas of the lower Doris Avenue Drain and lower West 5th Street Drain watersheds are agricultural land uses. However, aerial photography shows that almost all of the agricultural areas have been used for strawberry production with plastic covering much of the area. It is assumed, therefore, that the runoff density for the upper

Doris Avenue Drain watershed is applicable to the entire watersheds for all the drains. This should provide an upper bound on the flow rates.

Since HEC-RAS only allows hydrograph flows to enter the model area at the boundary, the entire watershed for each drain extending to the confluence with the Edison Canal was used for calculating input flows at the boundary. In addition, there is direct runoff contributing to the Edison Canal that does not flow through one of the three drains. To understand all the flows that could contribute to flooding along the Edison Canal, the direct runoff was divided based on the location of the drain confluences and added to the flows for each canal. For example, the flow entering the upstream end of Doris Avenue Drain in the model includes the runoff for the entire Doris Avenue Drain Watershed and the direct runoff to Edison Canal for the portion of the canal upstream of Doris Avenue Drain.

The flows thus calculated were used as the peak flow in the hydrographs. To simplify the shape of the hydrograph, peak flow was reached linearly over 24 hours and then held steady for 24 hours in the model.

Table Error! No text of specified style in document.**-1 500-year Flows for Model Upstream Boundary Conditions**

Model Upstream Boundary Location	FIS Location	FIS Flow	Watershed Area (mi²)	Model Flow
Santa Clara River	Santa Clara R at Mouth	270,000 cfs	na	270,000 cfs 7,646 cms
Doris Avenue Drain	Doris Avenue Drain	750 cfs for 0.4 mi^2	3.6	6,912 cfs 196 cms
West 5th Street Drain	Doris Avenue Drain		2.4	4,588 cfs 130 cms
Oxnard West Drain	Doris Avenue Drain		7.9	15,181 cfs 430 cms

2.2.2 Downstream Boundary Conditions

A stage hydrograph was used as the downstream boundary condition at the mouths of the Santa Clara River and Channel Islands Harbor and for the overflow of the Santa Clara River Breakout. The stage used was a constant elevation of mean higher high water (MHHW) or 5.27 feet for the entire model run time.

2.3 Other Model Input Data

Other model input includes the Manning's n to describe the roughness of each grid cell. A uniform Manning's n of 0.024 was applied to the entire study area. A computational time step of 3 seconds was used.

3. Results Discussion

Results of the 500-year 2D hydrodynamic model show that there is no flooding of the P3 site or the MGS property from the lower Santa Clara River, Santa Clara River Breakout, Edison Canal, Doris Avenue Drain, West 5th Street Drain, or Oxnard West Drain. The only ponding within the MGS property is in the Edison Canal and north of the berm along the northern property boundary. No ponding occurs on the P3 site. **Figure** Error! No text of specified style in document.**-6** shows the maximum ponding depth resulting from 500-year flows for the model study area, **Figure** Error! No text of specified style in document.**-7** shows the maximum ponding depths zoomed to the MGS property, and **Figure** Error! No text of specified style in document.**-8** provides a comparison of the model results and the FIRM flood zones.

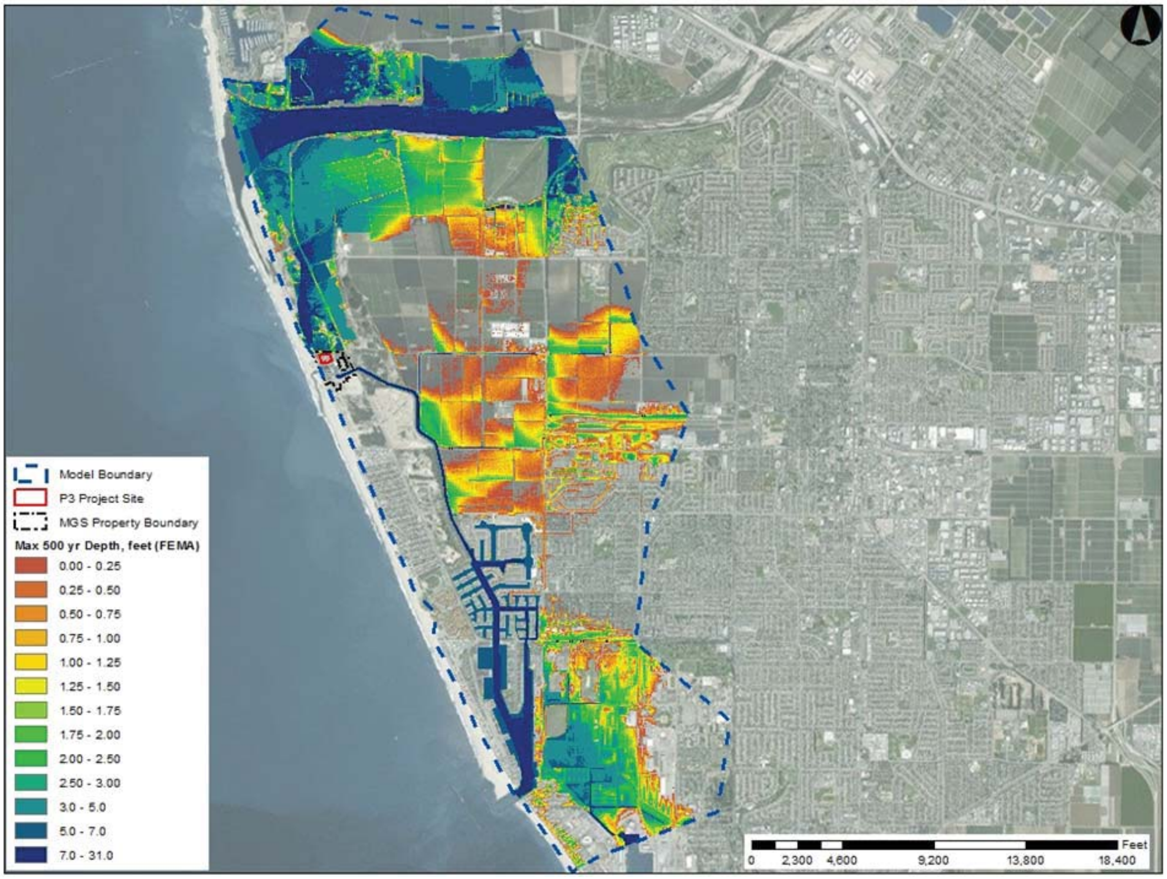


Figure Error! No text of specified style in document.**-6 500-year Maximum Flood Depth for Model Study Area**

The results shown in **Figure** Error! No text of specified style in document.**-6** are fairly consistent with the FEMA FIRM (see Figure 1-4) and indicate that the drains appear to be the source of the 500-year flooding shown on the effective FIRM at the P3 site, rather than the Santa Clara River. Since the Edison Canal can contain the 0.2% annual chance flow within its banks, flooding from the drains would not reach the P3 site.

Based on the 500-year inundation area determined from the 2D model, it is apparent that the P3 site should not be included in the area of shaded Zone X. **Figure** Error! No text of specified style in document.**-9** shows the proposed alteration of the shaded Zone X so that the 500-year floodplain is extended around the end of the Edison Canal and would not include the P3 site.

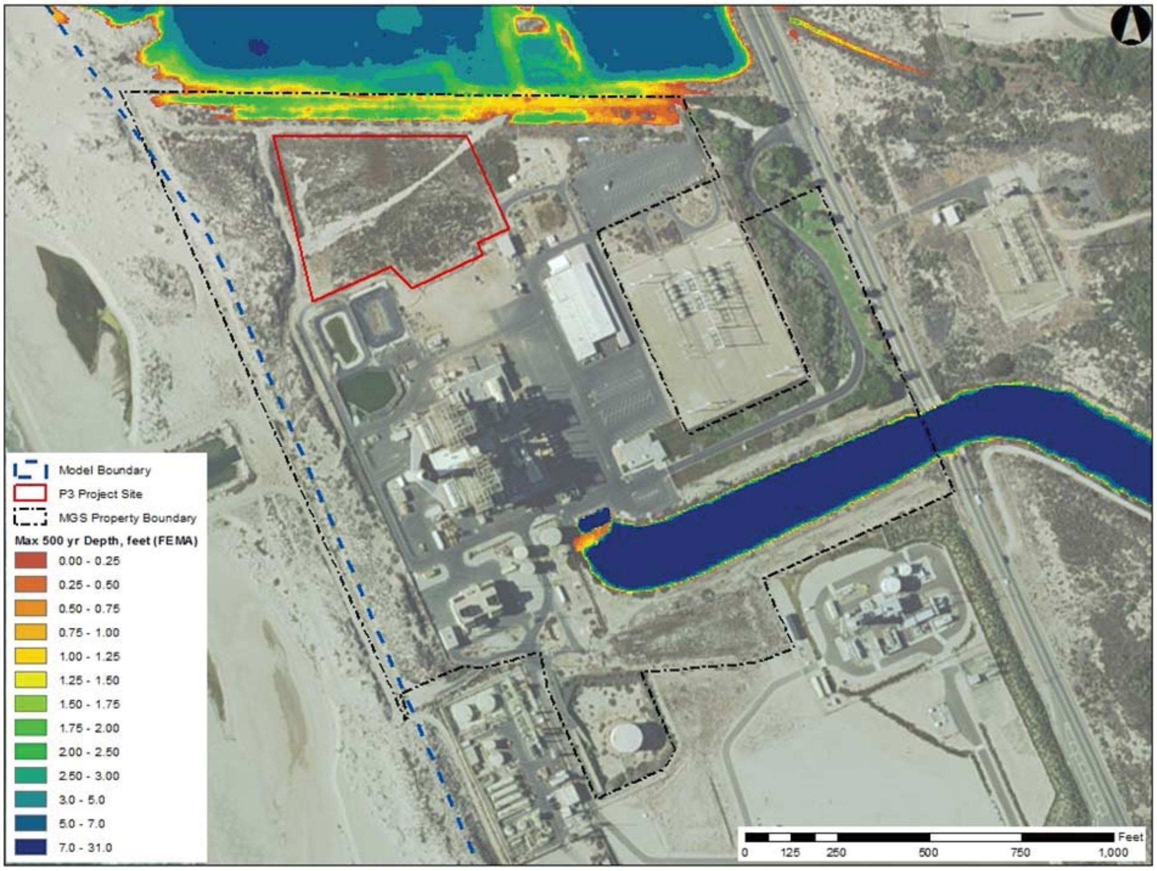


Figure Error! No text of specified style in document.**-7 500-year Maximum Flood Depth for MGS Property**

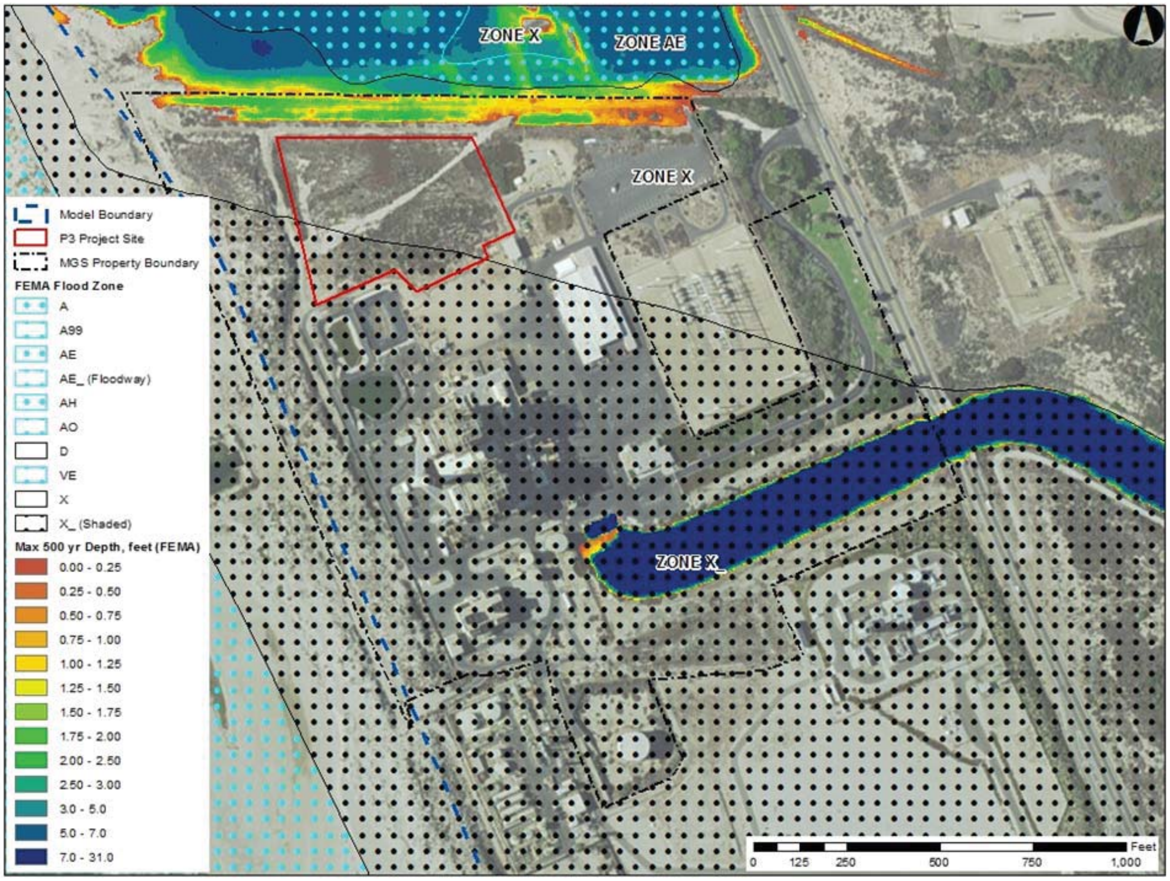


Figure Error! No text of specified style in document.**-8 500-year Maximum Flood Depth for MGS Property with Current FIRM Flood Zones**

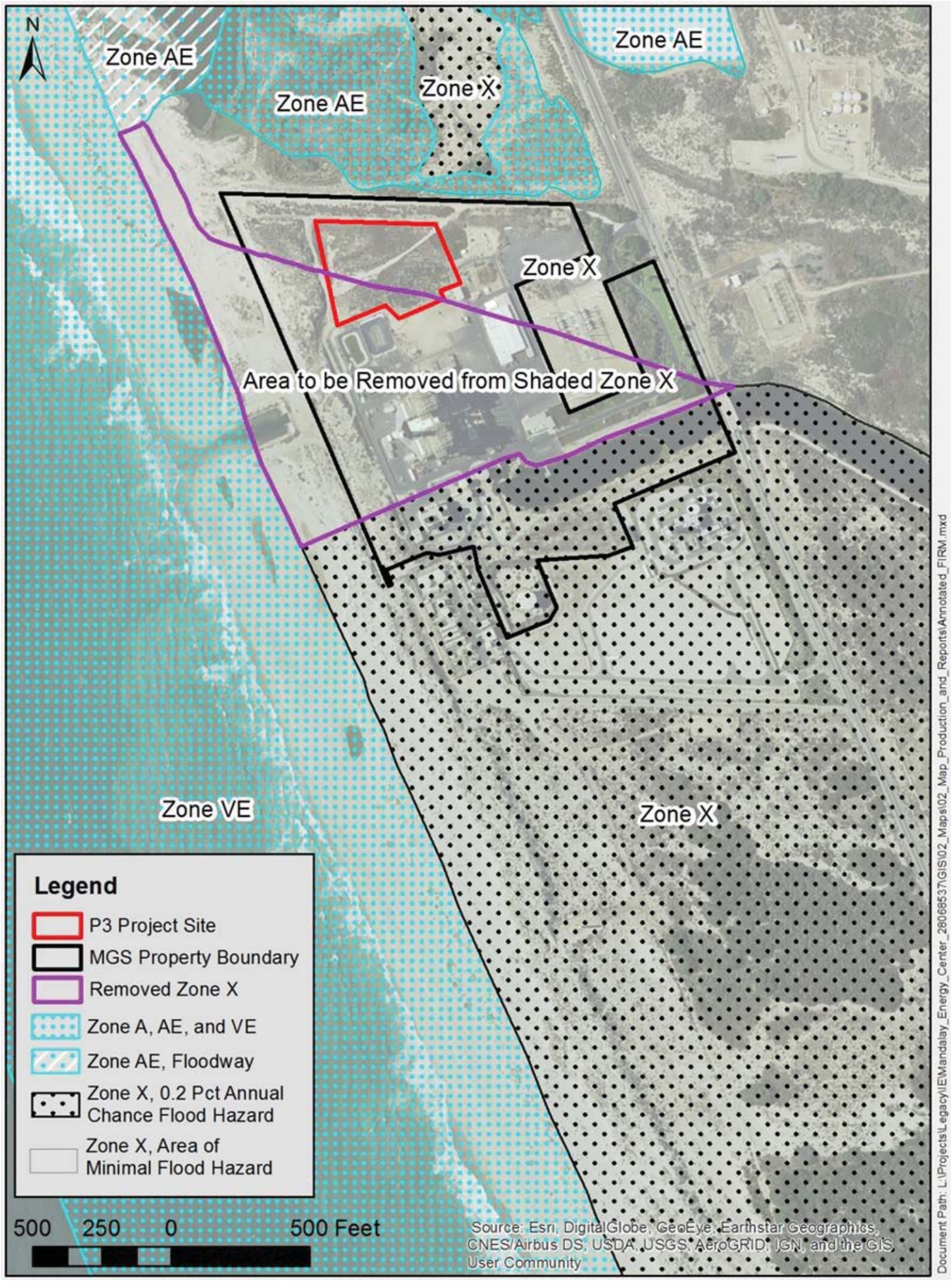


Figure Error! No text of specified style in document.**-9 Annotated FIRM**

4. References

FEMA Undated. Flood Insurance Rate Map (Work Map), City of Oxnard, CA. Maps 1 and 3. Undated.

FEMA 2010. Flood Insurance Rate Map, Ventura County, California and Incorporated Areas. Panels 885 and 905. Map Numbers 06111C0885E and 06111C0905E. Effective January 20, 2010.

FEMA 2015. Flood Insurance Study, Ventura County, California. Volumes 1, 2, and 3. Flood Insurance Study Number 06111CV001C. Revised January 7, 2015.

NOAA 2011. 2009 - 2011 CA Coastal Conservancy Coastal Lidar Project: Hydro-flattened Bare Earth DEM. Downloaded November 7, 2016. https://coast.noaa.gov/dataviewer

Saddleback Surveys, Inc. 2011. Topographic Survey Being a Control and Topographic Survey for Mandalay Generating Station.

ATTACHMENT A

AECOM

Phillip Mineart, P.E.
Hydrology, Hydraulics, Environmental Restoration and Water Quality

Areas of Expertise

Water Resources
Mathematical Modeling
Hydrology and Hydraulics

Education

MS/Civil Engineering/1983/Cornell University
BS/Environmental Resources Engineering/1979/Humboldt State University, Arcata, CA

Licenses/Registrations

Professional Engineer/CA/ #C44087/6/30/2017

Years of Experience

With AECOM (Formerly URS) 32
With Other Firms 2

Professional Associations

American Geophysical Union
American Society of Civil Engineers
American Water Resources Association

Mr. Mineart is a registered Professional Engineer in California. He has over 30 years of experience in the fields of hydrologic, hydraulic and hydrodynamic analysis, erosion and sediment transport modeling, environmental restoration, risk assessments, climate change and sea level rise. Below is a summary of his experience.

Experience

Coastal and Hydrodynamics

Technical Lead, Puente Power Project Application for Certification, NRG Oxnard Energy Center LLC. Managed the data collection and preparation of the Water Resources section of the Application for Certification (CEQA-equivalent document) for the proposed 262 megawatt natural gas-fired generation facility in Oxnard, California. Responsibilities included analyzing impacts of flooding due to sea level rise, tsunamis, and riverine sources. Analysis also included coastal hazards such as impacts from beach and dune erosion and/or accretion.

Sediment Transport and Tidal Flow Study for Facility Improvements to the Ammunition Pier and Turning Basin, Project Manager, Seal Beach Ca., 2016. The study purpose was to determine if proposed improvements at the Seal Beach Naval Weapons Station could alter the hydrodynamic regime and sediment dynamics as changes in the tidal currents, waves, or sedimentation patterns and impact coastal resources and/or the Seal Beach National Wildlife Refuge (SBNWR). Hydrodynamic models for tidal flow and sediment transport were developed. In addition, a wave model was developed to determine potential Surfside and Sunset Beach impacts. This study is intended to support the Environmental Assessment currently underway.

Port of San Francisco, Sea Level Rise Study, Coastal Engineer, San Francisco, CA, 2011. Determined the 100-year design water levels (Still Water Level and Wave Runup) along the Port of San Francisco shoreline, under various scenarios of Sea Level Rise. The DHI-MIKE21 Nearshore Wave model was used for wind-wave generation, and the Delft SWAN wave model was used for breakwater analysis. The DHI-MIKE21 hydrodynamics model was used for still water level analysis. Flood inundation maps of the estimated 100-year flood at present day, in year 2050, and year 2100 were developed. The maps were used to identify locations along the shoreline that could be subject to flooding or wave damage under future sea levels. Boundary conditions were obtained from NOAA tidal gauges and wave buoys, NWS wind data, and DWR Delta outflow data.

Port of Oakland, Oakland Airport Perimeter Dike Wave and Water Level Analysis in San Francisco Bay, Hydrodynamic Task Leader, Oakland, California, 2008. This Project involved modeling with DHI-MIKE21 Near-Shore Waves model, data analysis of water level and wave runup return frequency, and analysis of levees for sufficient crest height and riprap armor stability. Analysis was conducted for existing conditions and projected future conditions including sea level rise.

State Coastal Conservancy, South Bay Salt Ponds Restoration Project – Phase II, Senior Hydraulic Engineer, Southern San Francisco Bay, CA, 2012 – Ongoing. Responsible for hydrodynamic and sediment transport analysis for development of conceptual (10%) designs for restoration of former Cargill salt ponds in three pond complexes around southern San Francisco Bay. One and 2-dimentsional hydrodynamic modeling was conducted to develop optimal breach and channel sizes. Preliminary sediment transport analysis was conducted to aid in the decision on whether to use dredge material raise the level of subsided ponds or if natural sedimentation would be able to raise the level of the ponds in the presence of sea level rise.

Chevron, Kitmat LNG Project, Senior Hydraulic Engineer, 2014. URS developed a 3-dimensional hydrodynamic and sediment transport model of Clio Bay in British Columbia, Canada. In additional to the numerical modeling the project also included field data collection and laboratory analysis. The modeling and data were used to predict the behavior of soils excavated from the Kitimat LNG site, if the excavated materials were released from split-hull barges into Clio Bay with the objective of benthic habitat restoration. The computer modeling was used to predict the behavior of material single and multiple releases from barges and bottom mounding (STFATE and MDFATE models) and the dispersion of the suspended portion throughout Clio Bay (EFDC model).

San Francisco Public Utilities Commission (SFPUC), Tidal Power Feasibility Study, Technical Lead, San Francisco, CA, 2007. Technical lead for the hydrodynamic modeling of the San Francisco Bay to determine total extractable energy and percent of energy that can be extracted from tidal currents without adverse impacts to the Bay's tidal prism and overall ecosystem. The MIKE 21 model was used for two-dimensional modeling; the TRIM model was used for three-dimensional modeling.

Chevron, Castro Cove Sediment Remediation Project, Hydrodynamic Modeling Lead Engineer, Richmond, CA, 2012. Castro Cove is a small cove along the northern shore of San Francisco Bay. URS developed a remediation design for a contaminated mud flat. The mud flat was isolated from the tides during construction by a sheet pile wall. After remediation was complete URS developed a two-dimensional hydrodynamic model of Castro Cove including the sheet pile wall to determine the best approach to remove the sheet pile to minimize erosion of the remedial cap as each sheet pile was removed. The suggested approach was used in the removal of the sheet pile and remedial cap remained intact as the tide was gradually allowed to return to the construction site.

Knik Arm Bridge and Toll Authority, Knik Arm Crossing Hydrodynamic Study for EIS, Technical Leader, Anchorage, AK, 2005 – 2008. Developed two-dimensional hydrodynamic and sediment transport models for Knik Arm near Anchorage, Alaska. Knik Arm experiences 30-foot tides and has extremely large sediment inputs making modeling challenging. Model was calibrated to both historic and data collected specifically for this project. State-of –the-art sediment shear stress data were collected to aid in calibration. Modeling was conducted using the MIKE21 model.

Federal Aviation Administration (FAA), San Francisco Airport Reconfiguration EIR/EIS, Technical Leader, San Francisco, CA, 1999 – 2003. Technical leader for the hydrodynamic and sediment transport analysis for the San Francisco Airport Reconfiguration EIR/EIS. Two-and three-dimensional hydrodynamic models were developed using MIKE21 and TRIM. The models were calibrated/validated to over 30 current stations with a least 29 days of record, 7 suspended sediment stations with 5 months or longer records and 18 tide stations. The model study was used to predict changes to currents, sediment transport and morphology of the Bay due to the project. Mr. Mineart provided technical review for the concurrent water quality analysis of PCBs, Mercury, and trace metals. PCBs and Mercury were modeled using the MIKE two-dimensional sediment transport model, trace metals were simulated using the MIKE21 heavy metals model.

U.S. Department of the Interior (DOI), Bureau of Reclamation (USBR), San Joaquin River Restoration Program Reach 2B and Mendota Pool Bypass Project, Task Leader Water Resources and Climate Change Sections, Fresno and Madera Counties, CA, 2009 – Est. 2015. This project primarily involves developing project alternatives, preparing an Environmental Impact Statement/Environmental Impact Report (EIS/EIR), and providing permitting support for the project. Components of the project include increasing channel capacity, incorporating riparian habitat, and providing fish passage through the reach via the modification of existing structures, installing fish screens and diversions, and constructing a new channel. Mr. Mineart is responsible for the completion of the water resources section of the EIR/S (hydrology, geomorphology and water quality) and the climate change sections.

Elkhorn Slough Foundation, Parsons Slough Sill Project, Senior Hydraulic Engineer, Monterey County, CA, 2009– 2010. Provided senior technical review and over site for hydraulic modeling and scour analysis of Elkhorn Slough and Parsons Slough near Monterey CA. The analysis was used to aid in the design of an adjustable sill structure at the mouth of Parsons Slough to limit erosive tidal energy in Parsons Slough while allowing for sufficient flushing to maintain water quality. Results from the HEC-RAS model were analyzed to evaluate whether design alternatives would meet specified design criteria. The scour analysis was conducted to determine if the project would result in increased erosion at the proposed structure or at a nearby by railroad bridge.

Bremerton Naval Complex Erosion Protection Study, Technical Lead, Bremerton, WA, 2009 – 2012. A riprapped embankment was replaced with a soft bank sloped beach covered with approximately a 3-foot layer of a sand-gravel mix. Subsequent to the action, erosion was observed and a 3-foot layer of the sand-gravel mix was mostly gone. The objectives of the project are to provide an engineering study, develop alternatives and a construction design, specification, and cost estimate that will provide long-term protection of the area. A field program was conducted to collect wave, current and tidal data. A beach erosion model was developed to predict erosion of the beach under historic conditions and to model alternative solutions.

US Navy, Site 10 Shoreline Erosion Study and Five-Year Review, Lead Coastal Engineer, Indian Island, WA, 2009– 2010. The objective of this study was to develop and evaluate alternatives for preventing future shoreline erosion at the remediated and capped Northend landfill on Indian

Island on Port Townsend Bay, WA. Previous methods used on the "high energy" portion of the beach had failed. The technical approach for meeting the objectives included performing a records and literature review to obtain data, performing field reconnaissance of the site, developing shoreline erosion protection alternatives, and performing a comparative analysis of the alternatives. A conceptual design and cost estimate for the recommended alternative was developed.

ARCO, Army Creek Marsh Remediation Project, Senior Hydraulic Engineer, New Castle, DE, 2009– 2010. Oversaw the development of a two-dimensional hydrodynamic model of a muted tidal wetland located on Army Creek, near Delaware Bay, in Delaware. Water levels in Army Creek Marsh were simulated using the two-dimensional MIKE 21 flow model. The digital terrain input consisted of a flexible mesh. Existing conditions were modeled with a tide gate structure that only allowed flow out of the marsh. Water levels computed for existing conditions were used to evaluate the proposed restoration plan, which consists of the excavation of contaminated material and re-grading as necessary to allow for a range of marsh habitat. Potential future water levels at the restoration site were also evaluated with the tide gate operating to allow tidal flows into the marsh.

California Department of Fish & Game, Napa Plant Site Saltpond Restoration Project, Senior Technical Reviewer for Hydraulics and Hydrology, Napa County, CA, 2005-2010. Provided technical review and oversite for hydrodynamic and salinity modeling and sediment transport studies for approximately 1,400 acre restoration of former saltwater evaporation ponds along the Napa River, near Napa, CA. The project area contained three separate units. Models were developed for each unit. Salinity modeling was conducted as part of permit compliance to insure that there would be no adverse impacts to the surround water bodies after breaching the former salt ponds.

Mt. View Sanitary District and Shell Oil Spill Litigation Trustees, Peyton Slough Studies, Task Leader, Martinez, CA, 1986-87 and 1994-95, 2008. Directed hydraulic and hydrologic study of Peyton Slough and surrounding wetlands, which receives wastewater wetland effluent. Modeled hydrologic scenarios to predict plant community response and evaluate restoration options. Developed MIKE11 model to analyze hydraulic capacity of the channels and develop specifications for hydraulic control facilities.

U.S. Steel, U.S. Steel Shearwater Remediation Project, Technical Lead, South San Francisco, CA, 1999 – 2002. Analyzed potential for erosion at the U.S. Steel Shearwater Remediation Project site at Oyster Cove in the San Francisco Bay. Determined hydraulic parameters used to calculate erosion of remediation cap in the sub-tidal zone from RMA2, a two-dimensional finite element hydrodynamic model. Evaluated potential for erosion in the intertidal zone based on the stability of the sandy slope.

Public Service Enterprise Group (PSEG), Dennis Township Wetland Restoration Project, Hydrodynamic Modeler, Delmont, NJ, 1994-95. Developed two-dimensional RMA2 model for abandoned hay farm along Delaware Bay. The model was used to analyze and design new channels and levee breaches that would optimize chances for successful restoration.

Public Service Enterprise Group (PSEG), Thompson's Beach – Maurice River Township Wetland Restoration Project, Hydrodynamic Modeler, Delmont, NJ, 1995-96. Developed two-dimensional RMA2 model for abandoned and flooded hay farm along Delaware Bay. The existing levees has breached in several locations resulting in a severely muted tidal condition. The model was used to analyze and design new channels and levee breaches that would optimize chances for successful restoration.

Hayward Area Recreation and Park District, Hydraulic Analysis, Oliver Brothers Wetland Enhancement Project, Task Leader, Hayward, CA, 1996-2003. Evaluated existing hydrologic conditions and developed hydraulic design (e.g., culverts, channels) for adjacent wetlands. Plan integrated endangered species habitat enhancement with protection and interpretation of cultural resource values and public access.

Flooding and Hydrodynamics

State Coastal Conservancy, Bay Area Extreme Storm, Project Manager, 2014. AECOM developed a definition for an extreme storm event for the Bay Area. Hydrologic and hydraulic models were developed for major streams in the Bay Area including most streams in Santa Clara County; Lower Walnut Creek in Contra Costa County, San Francisquito Creek in San Mateo County, San Anselmo Creek in Marin County and San Francisco Bay. Results from these analyses were supplemented with a review a FEMA and local hydrologic flood studies to develop inundation depths and durations for major urban areas around the Bay Area. These were used by economists to estimate the potential damage from an extreme storm event.

Santa Clara Valley Water District, Almaden-Calero Canal Hydrology Study. Ongoing. The Almaden-Calero Canal is used to transport water from Almaden Reservoir to Calero Reservoir. Both reservoirs are used for water supply. A continuous simulation HEC-HMS model is being developed to estimate the inflow into the canal from storm water runoff. A long period of rainfall will be simulated and then used to generate a frequency curve for runoff into the canal.

State Coastal Conservancy and California American Water, Carmel River Reroute and San Clemente Dam Removal Project, Senior Review, Monterey County, California, 2008 – present. This project includes design and geotechnical exploration services for the San Clemente Dam Removal Project. The project will meet the steelhead passage and dam seismic safety goals through the removal of the dam, relocation of accumulated sediment in San Clemente Creek, and restoration of San Clemente Creek to pre-dam conditions. A portion of Carmel River will be permanently bypassed by cutting a 450-foot-long channel between Carmel River and San Clemente Creek, approximately 2,500 feet upstream from the dam. Mr. Mineart provided senior oversight for the hydraulic, flood inundation and sediment transport analyses. The sediment transport analysis included estimating the changes in morphology of the Carmel River with and without the project and how those changes could affect flooding. Analysis included the implementation of the HEC-HMS, HEC-RAS and SRH-1D models.

City of Daly City, Mussel Rock Landfill Stormwater Evaluation, Task Leader, 2015. Mussel Rock Landfill is a closed landfill located on the Pacific Ocean coastline in Daly City. The goal of the project was to evaluate the adequacy of the existing storm drain system under existing and future climate change conditions, recommend upgrades if needed and evaluate the adequacy of the adjacent seawall with sea level rise. An XPSWMM model was developed for the drainage system based on as-built drawings and a field inspection. A range of design storms were simulated from a 2-year event to a 100-year event for existing climate conditions and accounting for climate change to the year 2050. Wave runup calculations were conducted for the seawall with and without sea level rise.

California Coastal Conservancy, Santa Clara River Restoration, Project Manager, Ventura County CA, 2003-2005. Technical Leader for hydrology and hydraulic analysis of the restoration of the Santa Clara River in Ventura County. He developed a water balance model for the river to identify all major sources and sinks of flow into and out of the river. A HEC-RAS hydraulic model of about 20 miles of the river was developed. A continuous simulation HEC-HMS hydrology model for the 1000+ square mile watershed was also developed.

Bay Area Rapid Transit (BART). Letter of Map Revision (LOMR). Alameda County. Hydraulic engineer responsible for completing and submitting LOMR application to FEMA. LOMR application was submitted as part of the Warm Springs Extension Project. A section of the project passed through a FEMA mapped floodplain that had been modified by previous projects, completed by others, but never remapped. LOMR was accepted by FEMA and the BART project area was removed from the floodplain.

City of San Jose. CLOMR and LOMR Application. San Jose, CA.
A Conditional Letter of Map Revision (CLOMR) was submitted to and accepted by FEMA for a project undertaken by the City at a location adjacent to Coyote Creek in San Jose. After construction of the project was complete a Letter of Map Revision application was submitted to FEMA for review. The LOMR is still under review by FEMA.

Pacific Gas and Electric Company (PG&E), L400/402 Cache Creek Erosion Study, Project Manager, Yolo County, CA. Since the original installation of natural gas pipelines in the 1960s Cache Creek has incised almost 20 feet endangering the safety of the pipelines. URS conducted an assessment of the geomorphology, geologic and geotechnical conditions in the vicinity of the gas pipeline crossings. The study included an evaluation of the channel dynamics, stream hydraulics and erosion and sediment transport potential in the vicinity of the pipeline crossing. The study was updated in 2014 prior to repair of the pipeline crossing.

Pacific Gas and Electric Company (PG&E), Hydrologic Services Pipelines Crossing L400/401, L-400 MP 141.7, Project Manager, Tehama County, CA, 2014. In 2012 during an inspection of its natural gas pipelines the clearing crew discovered that about 50 feet of the pipeline was exposed in Salt Creek. The purpose of the project was to evaluate the causes of the exposed pipeline and determine possible repairs to protect the exposed pipeline. A field inspection with a hydrologist and geomorphologist was conducted; historic data including aerial photographs and historic surveys were analyzed; and hydrology and hydraulic modeling and sediment transport capacity was calculated. Based on the analysis possible protection measures were provided.

Rhodia, Inc., Rhodia-Peyton Slough Remediation and Restoration, Technical Leader, Martinez, CA, 2000 – ongoing. Technical lead for the design and analysis of a tidal channel, tide gates, groundwater water balance, and wetland design as part of a large remediation project in Martinez, CA. The tidal channel feeds over 100 acres of wetlands and ponds. Unsteady HEC-RAS, RMA2 and MIKE21 models were used in the analysis of the channels, ponds and wetland. For the water balance analysis three double ring infiltrometers were installed to estimate infiltration rates. Two underwater seepage meters were installed to estimate seepage to groundwater from pond bottoms. Conducted screening level fate and transport groundwater modeling and participated in the review of higher level fate and transport modeling. Since construction was completed adaptive management activities have been conducted include shoreline repairs, data collection and erosion control.

Department of Water Resources (DWR), Delta Risk Management Strategy (DRMS), Hydrologic Engineer, Sacramento – San Joaquin Delta, CA, 2005 – 2009. This project was a comprehensive risk analysis of the Sacramento-San Joaquin Delta and Suisan March including the development of risk management strategies. The hazards included earthquakes, flooding, subsidence, normal operating conditions "sunny weather", and climate changes. The consequences of levee failures in the Delta include impacts to: the levee integrity, the water quality, the water reliability for export, the ecosystem, and the direct and indirect economic impacts. As a participant on the flood hazards working group Mr. Mineart helped develop innovative methods based on probabilistic models to identify flood risks to levees from storms and waves. The study assessed the risk due to the above stressing events for 50-year, 100-year and 200-year time horizons. Since the hydraulics in the Delta is strongly influenced by tidal conditions, sea level rise was incorporated into the future predictions of tides in the Delta. For stormwater runoff into the Delta, estimates from global climate models for future rainfall volumes and patterns were used to adjust flood frequency curves to account for changes that may occur by the year 2050 and 2100.

Kinder-Morgan, Inc., Rodeo Creek Stream Restoration, Project Leader, Contra Costa County, CA, 2003-2004. Project leader for stream restoration project on Rodeo Creek in Contra Costa County, CA. Rodeo Creek is deeply incised and URS developed environmentally friendly restoration techniques. Mr. Mineart directed the HEC-RAS and HEC6 analysis to estimate the long term erosion of the channel with and without mitigation. He conducted rainfall frequency analysis and HEC-HMS analysis. He analyzed the sediment transport capacity of the creek for major rainfall events in last 15 years. He oversaw development of alternative restoration measures.

Granite Rock, Wilson Quarry Inundation Study, Senior Engineer, Aromas, CA, 2011. Provided senior review of flood inundation study for the Pajaro River in San Benito County, Ca. GIS was used to develop cross-sections for a HEC-RAS model. A flood frequency analysis was performed using peak flows measured at a near-by USGS gage to obtain peak flow rates associated with the 100-year, 500-year, and 1,000-year floods.

U.S. Army Corps of Engineers (USACE), Natomas Levee Risk Assessment Methodology, Hydraulic Engineer, Nationwide, 2007 – 2008. As part of the USACE’s efforts to inventory and evaluate flood protection systems throughout the United States, URS developed probabilistic based tools to assess risk of failure due to wave or river erosion of levees. Mr. Mineart was Technical Leader for developing the methods to incorporate into the model for current and wave erosion rates.

City of Santa Barbara, Santa Barbara Airport Runway Safety Project, Task Leader, Santa Barbara, CA, 2003-2008. The Santa Barbara Airport is in the floodplain of five creeks and is immediately adjacent to extensive wetlands. Mr. Mineart developed sediment transport and hydrodynamic models of the streams and wetlands around Santa Barbara Airport to analyze alternative options for lengthening the safety area of the airport's main runway. A storm drain model using SWMM was developed to produce a storm drainage master plan for the airport property. A HEC-RAS model was developed to estimate flooding of the airport property and to complete a CLOMR and LOMR process for FEMA.

Calpine Energy, Flood Inundation Study for Pastoria Energy Facility, Task Leader, Grapevine CA, 1998 – 2000. Task leader for water resources section of the Pastoria Energy Facility AFC. Mr. Mineart's responsibilities included hydrology, flood analysis, water quality and development of mitigation measures. The hydrology and flood study included analysis of existing rainfall and flow data, development of design storm hydrographs, and implementation of the HEC-RAS model for flood plain delineation. Mitigation measures were developed to reduce the potential for flooding at the proposed facility site.

Roseville Energy LLP, Roseville Energy Facility AFC, Water Resources Task Lead, Roseville, CA, 2000 – 2002. Evaluated the potential for impacts as a result of construction and operation of the Roseville Energy Facility to assist in preparation of the Application for Certification. Proposed mitigation measures to minimize impacts to receiving waters from stormwater runoff. Measures included the implementation of Best Management Practices to control erosion, sediment, and other pollutants, as specified for compliance with the Stormwater Pollution Prevention Plan.

Sunrise Power Company, Sunrise II Power Project, Water Resources Task Lead, Bakersfield, CA, 2001 – 2004. Completed the Water Resources section of the Application for Certification of the Sunrise II Power Project. Compiled application for Underground Injection Control Program permit for deep well injection of wastewater.

City of Albany, Curtis-Neilson Storm Drain Analysis Project, Project Manager, Albany, CA, 2006 – 2007. Oversaw the development of an XPSWMM model for portion of the City of Albany's storm drain system. The model was used to identify local bottlenecks and to aid in the design of a 1,300-foot-long storm drain pipe to reduce local flooding. The proposed design replaced existing storm drains under private property with minimal disruption to the neighborhood.

U.S. Department of Energy (DOE), Yucca Mountain Nuclear Repository Flood Study, Task Leader, Yucca Mountain, NV, 1999 – 2003, 2007 – 2008. Managed hydraulic/hydrology study for the Yucca Mountain Nuclear Repository in Nevada. The project involved a flood risk assessment and preliminary design for mitigation measures. The analysis involved predicting rainfall and flood inundation in an alluvial fan with uncertain flow paths and high sediment transport. Channel geometry and substrate were used to predict water surface elevations, velocities, and bed shear stress. The effects of sediment transport on flow resistance were assessed. Directed HEC-1 and HEC-RAS analysis.

Dam Design and Analysis

San Francisco Public Utilities Commission (SFPUC), San Andreas Dam Inundation Mapping, Project Manager, San Mateo County, CA, 2015. Project Manager and engineer responsible for the analysis of the dam breach of the San Andreas Dam. Estimated breach characteristics and routed flood wave downstream to San Francisco Bay and mapped resulting inundated area. Project also included the analysis and mapping of the inundation area due to emergency releases from the dam. Inundation was primarily in urban areas. Analysis used the MIKE21 two-dimensional hydrodynamic model.

Contra Costa Water District (CCWD), CALFED Los Vaqueros Reservoir Expansion Studies, Hydraulic Engineer, Contra Costa County, CA, 2001 – 2007, 2011 – 2012. Responsible for the analysis of the dam breach and flood inundation modeling of Los Vaqueros Dam. Mr. Mineart modeled the failure of the earthen embankment dam using the BREACH model and routed the resulting flood wave downstream into the Sacramento-San Joaquin River Delta using the FLDWAV model. Mr. Mineart conducted the breach analysis and provided technical review for the flood routing and inundation mapping of the expansion of Los Vaqueros Reservoir. The flood routing was conducted using the MIKE21 two dimensional model.

San Francisco Public Utilities Commission (SFPUC), Lower Crystal Springs Dam Inundation Mapping, Independent Technical Review, San Mateo County, CA, 2010 – 2011. Provided technical review for dam breach and flood inundation mapping for the Lower Crystal Springs Reservoir and floodplain maps on San Mateo Creek. Analysis was conducted using the two-dimensional MIKE21 model. Inundation maps were developed in ArcGIS.

Empire Land, Pelona Vista Detention Basin Preliminary Design, Hydraulic Engineer, City of Palmdale, CA, 2004 – 2005. This 1000 acre-feet stormwater detention basin reduces the Los Angeles County 50-year flood event runoff from a maximum discharge of 6,400 cfs to 750 cfs to prevent downstream flooding. Mr. Mineart conducted hydrologic studies for various return period storm events including PMP as part of spillway design.

California American Water Company, San Clemente Dam, Hydraulic Engineer, Monterey County, CA, 1997 – 1999. San Clemente Dam is a concrete arch dam on the Carmel River that is almost completely full of sediment. Mr. Mineart conducted a dam breach and inundation study using the NWS DAMBRK model.

Outfall/Dilution/Intake Studies

City of Benicia, Benicia WWTP Effluent Initial Dilution at Long-Term Average, Design, and Peak Daily Flow Rates, Project Manager, San Francisco Bay, CA, 2012-2013. The City of Benicia operates a diffuser that discharges 500 feet offshore of its WWTP into the Carquinez Straits. The City's NPDES permit required the City to perform a dilution modeling study to justify the continued use of dilution credits for the determination of water quality based effluent limits. A dilution analysis was conducted using different effluent flow rates, seasonal conditions, and a year of current speed, direction and depth data to capture variability in dilution due to tidal conditions. The results of the dilution modeling confirmed that the original design and installation of the diffuser results in an initial dilution considerably greater than 10:1 in the receiving water under a variety of conditions and under critical ambient conditions

Crockett Cogeneration, Dye Study and Near-Field Dilution Modeling for Crockett Cogeneration and C&H Sugar Outfall, Project Manager, San Francisco Bay, CA, 2010-2011. Crockett Cogeneration and C&H Sugar share an industrial discharge to San Francisco Bay. The dilution study was necessary to determine the initial dilution that can be obtained in the Carquinez Strait near slack tide. Dye studies were conducted on two days to determine the effluent dilution during periods with low current speeds and to validate the dilution model. The dilution modeling study was used to evaluate the expected dilution at slack tide for periods with average and maximum effluent flow rates. The US EPA's Visual Plumes model (Frick et. al, 2003) was used to simulate the dilution of the discharge.

Chevron, Plume Modeling of Hydrotest Water Discharge, MTOE Pipeline Project, Task Leader, Angola, 2008. An analysis of a proposed discharge of hydrotest water into coastal waters off the coast of Angola was conducted in response to a request from Chevron. The purpose of the analysis was to estimate the near-field dilution of hydrotest water with the surrounding ocean water. Data on ambient conditions were obtained from the National Oceanographic Data Center for the area offshore of Angola. Based on the modeling and toxicity data for Bactron B1150, the biocide used in the test, the extent of impact to fish and plankton was estimated.

EBMUD, Near-Field Dilution Study for East Bay Municipal Utility District (EBMUD) Outfall, Project Manager, San Francisco Bay, CA, 2008. East Bay Municipal Utility District (EBMUD) provides treatment of wastewater for several communities East of San Francisco Bay. The treated wastewater is discharged to the San Francisco Bay through an outfall diffuser. EBMUD retained URS Corporation to model the expected near-field dilution of the effluent and determine the ammonia concentration at the edge of the zone of initial dilution. The Monte Carlo method was used to generate a distribution of dilution values. The use of a probabilistic analysis provides a better understanding of the water quality impacts of a discharge then the more traditional “worst case” and sensitivity analysis.

New York, Dye Study and Modeling of Wastewater Outfall, SI Group, Project Engineer, Schenectady, 2009. Project engineer responsible for dilution study on the Mohawk River in New York for permit compliance. A winter and summer dye study was conducted to validate dilution model. The near-field and far-field dilution of a wastewater plume discharged into the Mohawk River was calculated using the Visual Plumes model and in-house analysis methods.

Larry Walker Associates, EBDA Anti-Degradation Analysis, Project Manager, San Francisco Bay, CA, 2004 – 2005. The MIKE 21 hydrodynamic model of the San Francisco Bay developed by URS was used to analyze the potential for changes in copper and nickel concentrations in San Francisco Bay due to increased discharge from the East Bay Dischargers Authority outfall offshore from Alameda, CA. Impacts to Bay water quality were analyzed for a large portion of the Bay. Discharges under current and projected future conditions (including numerous other discharges) were analyzed.

City West Water, Technical Oversight, Altoona Wastewater Treatment Plant Outfall Dilution Modeling Study, Peer Review, Altoona, Australia,

2008. City West Water is considering using a Recycled Water plant to purify and reuse Altona Treatment Plant (ATP) effluent for industrial and irrigation use. CWW hired URS to conduct a modelling study of the outfall under both existing conditions and future conditions (with the recycled water plant concentrate). To conduct the modelling study, URS utilized the Visual Plumes (VP) model. As input to the model, URS collected a full range of ambient and effluent data, so that a total of 17,472 independent cases were evaluated. Concentrations of Ammonia, BOD, TDS, E Coli, TN, TP, and TSS at the edge of the mixing zone were analyzed, and statistics were generated.

Marin Municipal Water District (MMWD), EIR for Desalinization Plant, Task Leader, Marin County, CA, 1991, 2003 – 2004. In 1991 Conducted diffuser dilution analysis for the Marin Municipal Water District (MMWD) as part environmental study of planned desalination plant for water supply. MMWD planned to use an underutilized existing wastewater treatment plant diffuser for disposal of desalination reject water. Because of the daily variation in the flow rates of the wastewater treatment plant, the discharge density fluctuated between positive and negative buoyancy. Used EPA's CORMIX II model to estimate dilution and mixing zone size. To verify model a dye study was undertaken to estimate dilution under existing operating conditions. In 2003-2004 conducted probabilistic study of the proposed discharge using EPA's Visual Plumes model. Calculated the probability that NPDES permit conditions would be violated under varying flow and ambient conditions. Determined that adding brine to wastewater discharge would result in an extremely small probably of exceeding NPDES permit conditions.

Potlatch Corp., Outfall Dilution Study, Project Manager, Clearwater, ID, 1998. Conducted mixing zone analysis, using EPA's Plumes model, of industrial discharge in the Snake River in Idaho. Mixing zone was calculated for temperature and water quality parameters. Detailed in-situ temperature and conductivity measurements were made to validate the model and estimate model error. A statistical event tree analysis was conducted to determine the uncertainty in model results based on variability in ambient conditions.

Dow Chemical Company, Brazos River Dilution Study, Modeling Lead, Freeport, TX, 2000. Based on a recommendation from the TNRCC, developed a quasi-three dimensional WASP5 model of the Brazos River. The model was used to calculate the transport of pollutants discharging into the Brazos River from groundwater. Three dimensional velocity and salinity data were collected to aid in model setup. Typical dilution factors were calculated for ebb and flood tides.

Kvaerner Metals, Outfall Dilution Study, Task Leader, Philippines, 1998. Conducted probabilistic modeling for negatively buoyant discharge from mining operation. Use a lattin-hyper cube technique to efficiently generate probably distribution of dilution from outfall. The results were used to determine uncertainty in model results to aid in design and permit compliance.

DuPont De Nemours & Company, NPDES Permit Renewal, Outfall Dilution Study, Project Manager, 1993. Conducted thermal discharge studies in the Niagara River in New York for chemical plant discharge. Surface discharge was modeled using empirical relationships since EPA models were not capable of modeling buoyant surface discharge in a cross flow. Observed temperature data was used to calibrate empirical model.

Outfall Dilution Studies, Task Leader, Various Locations and Clients. Designed outfall diffusers for use in disposing of desalination reject water in San Diego Bay and off Santa Barbara, California. Used EPA PLUMES models for dilution estimation and in-house hydraulic model for diffuser design.

Echo Bay Mines, Near-field and Far-field Dilution Study, Task Leader, Juneau, AK, 1993. Conducted both near and far field dilution study and diffuser design study for tailings pond discharge into Gastineau Channel in Alaska. Two models were developed for the study, a dilution model to estimate near-field dilution and because of the low flushing rates in Gastineau Channel a far field pollutant build-up model. Estimated long- term build- up of pollutants in Channel due to long term continuous discharge.

Intake Studies, Task Leader, Various Locations and Clients. Developed and implemented two-dimensional hydrodynamic model of the lower end of Klamath Lake to determine the impacts to lake circulation of an industrial discharge and intake. Developed a two-dimensional CE-QUAL-W2 model for Lake Travis near Austin, Texas to simulate the transport of contaminants in the lake including the effects of the intake configuration. Analyzed different intake configurations for hydro-power intake on Lake Almanor in Northern California to determine how to best manage cold water resource. Analyzed potential recirculation between intake and outfall for proposed desalination project in San Francisco Bay.

Water Quality Studies

U.S. Bureau of Reclamation (USBR), Delta-Mendota Canal Recirculation Feasibility Study, Hydraulic and Water Quality Engineer, Sacramento, CA, 2006 – 2011. Worked on water quality and sediment portion of U.S. Bureau of Reclamation (USBR) study to determine the feasibility of re-circulation of Delta water to the San Joaquin River to meet water quality and flow standards. Reviewed and analyzed TSS and erosion data collected to aid in determining impacts of increased flow releases on water quality in the San Joaquin River. Reviewed DSM2 modeling results to determine impacts to salinity levels in the Delta from modified operations.

City of San Jose, South Bay Copper Nickel TMDL Source Identification Project, San Jose, CA, 1997 – 1999. Assisted in the development of watershed and sediment loads to the South Bay for the South Bay Copper and Nickel TMDL. Developed data and analysis methodologies for estimating the contribution of in-bay sediment to the total Bay load. Identified data gaps and methods for improving estimates.

Bay Area Stormwater Management Agencies Association, BASMAA Long-Term Data Analysis Project, Oakland, CA, 1995 – 1996. Developed land use based water quality load estimates for Bay Area Association of Stormwater Management Agencies. Compiled data from three counties in San Francisco Bay Area. Developed multiple linear regression model between measured concentrations, land use and runoff coefficients.

Lower Colorado River Authority, MTBE Pipeline Spill, TX. Developed CE-QUAL-W2 model for Lake Travis near Austin, Texas. The model was used to simulate a MTBE and benzene spill into the Lake. Model results were used to determine the maximum spill that would not exceed water quality criteria at different intake points in the Lake. Volatilization was estimated by calibrating separate volatilization model to lake model results.

Alameda County Public Works Agency, Storm Inlet cleaning BMP Study, Task Leader, Alameda Countywide Clean Water Program, Hayward, CA. Conducted storm inlet cleaning study in Alameda County. The study involved the cleaning of 60 storm inlets at annual, semi-annual, quarterly and monthly frequencies to determine optimal cleaning frequency. Both the mass and volume of sediment removed were measured as well as the chemical quality of sediments to determine pollutant load removal.

City of San Jose, Street Sweep Effectiveness Study, Project Manager, CA. Conducted comparative study of the effectiveness of five different street sweepers for San Jose, California. A statistical model of the study was developed prior to initiation of the study to determine the minimum number of samples necessary to arrive at a statistically valid result. The volume and mass of sediment from the five sweepers were measured from eight randomly selected sweeping routes. For each sweeper and route the chemical quality of the sediment collected was analyzed. An ANOVA analysis was conducted on the results to determine which sweeper(s) was most effective at picking up selected pollutants.

Groundwater

U.S. Environmental Protection Agency (USEPA), Development of EPA MULTIMED Model, Model Developer, Nationwide. Participated in the development of the EPA's Multimed and EPACML groundwater/surface water contaminant transport models. Mr. Mineart's responsibilities included linking an unsaturated zone flow and transport model with a saturated zone transport model, designing and implementing a Monte Carlo pre- and post-processor for the linked model and conducting testing of model.

East Bay Municipal Utility District (EBMUD), Camanche Hills Hunting Preserve, Project Manager, Land Applications Data Report, 2006. Developed a water balance model to estimate maximum loading rate for land application of wastewater that was protective of groundwater for EBMUD’s Camanche Hills Hunting Preserve. Calculated maximum hydraulic and nutrient loading rates and amount of land required to prevent degradation.

American Petroleum Institute, SESOIL Development for API Risk Assessment Decision Support System, Model Developer, 1992. Modified the SESOIL unsaturated zone transport model for inclusion into decision support system. Modifications included simplifications to data input files and the addition of new volatile emissions routine. The new addition included the volatilization routine described in EPA’s Superfund Exposure Assessment Manual.

Western Farms Services, Contaminate Fate and Transport Modeling, Technical Lead, 1992 – 1994. Implemented SESOIL groundwater transport model to determine clean up levels for several pesticide/fertilizer distribution centers. The model was used to back calculate the allowable mass/concentrations of contaminants that could be left in the soil and meet water quality criteria at property boundaries.

Granite Rock Company, Geotechnical and Hydrological Study of Overburden Embankment Expansion, Hydraulic Engineer, San Benito County CA, 2000 – 2005. Engineer responsible for hydrological studies of proposed overburden placement from long term operation of large gravel mine. Hydrologic studies consisted of infiltration studies, rainfall-runoff analysis and preliminary design of several retention and infiltration basins to limit volume and rate of runoff to pre-project conditions.

EIR/EIS Experience

Sonoma County Permit and Resource Management Department, Sutter Medical Center of Santa Rosa/Luther Burbank Center for the Arts Joint Master Plan Initial Study and Environmental Impact Report, Hydrology and Water Quality Task Leader, Santa Rosa, CA, 2006 – 2010. Sutter proposed to build new hospital facilities on a 79 acre parcel to replace two medical facility campuses which were not in compliance with the Hospital Seismic Safety Act (SB1953). The project scope includes preparing a CEQA Initial Study and Environmental Impact Report (EIR). Major issues addressed included water supply and storm water runoff from the site. Water supply issues were addressed through mitigation measures that reduced off-site water use. Storm water runoff issuers were addressed through Best Management Practices (BMPs) that included detention ponds incorporated into site design.

Federal Rail Administration, (FRA), California High-Speed Rail Authority, (CHSRA), California High Speed Rail Environmental Impact Analysis – Fresno and Palmdale, CA Sections, Hydrology and Water Quality Task Leader, 2008 – Present. Responsible for completing the hydrology and water quality sections of the EIR and EIS for the Fresno to Bakersfield and the Bakersfield to Palmdale sections of the CA high speed train project. Analysis included the impacts to floodplains, local drainage and storm water runoff. Streams on the 303(d) list or with active or proposed TMDLs were identified and potential impacts estimated.

San Luis and Delta-Mendota Water Authority in cooperation with U.S. Department of the Interior, Bureau of Reclamation (USBR), NEPA/CEQA Compliance for Grassland Bypass Project, Water Resources Task Leader, Los Banos, CA, 1999- 2001. Task leader for the water resources section of the EIR/EIS on use of a portion of the federal San Luis Drain to convey agricultural drainage water around wetland habitat areas for the Grasslands Bypass Project. Developed a water balance model for the approximately 100,000-acre Grassland drainage area used to estimate impacts.

San Joaquin River Exchange Contractors Water Authority, San Joaquin River Water Transfers, Task Leader, San Joaquin Valley, CA, 1999 – 2000. Task leader for water resources section for NEPA/CEQA Compliance for Water Transfers and Conveyance for San Joaquin River Exchange Contractors Water Authority. Participated in preparation of EA/IS on water transfer and conveyance project for wetland habitat enhancement and for agricultural use on the westside of the San Joaquin Valley. Developed water balance model that included infiltration, evaporation, crop use and deep percolation.

San Joaquin River Group Authority, Water Acquisition Supplemental EIS/EIR, Task Leader, San Joaquin Valley, CA, 2000 – 2001. Task leader for water resource section for Supplemental EIS/EIR on acquisition of up to

47,000 acre-feet of additional water (above the 110,000 acre-feet already approved) to provide additional stream flows for anadomous fish in the San Joaquin River for a 31-day spring pulse flow. The project was conducted for the San Joaquin River Group Authority in cooperation with U.S. Department of the Interior, Bureau of Reclamation

Publications

Thermal behavior of a multi-reservoir hydroelectric system (with R. Cross, K. Voos, and W. Lifton). Paper presented at ASCE/Waterpower '87 International Conference on Hydropower, August 19-21, 1987. Portland, Oregon.

Feasibility of cold water releases from Lake Britton (with R. Cross, W. Lifton, and D. Gilbert). Paper presented at 14th Annual Conference on Water Resources Planning and Management Modeling, Monitoring, and Managing Water Resources Systems, March 16-18, 1987. Kansas City, Missouri

Observations of upwelling near breakwaters (with P. Mangarella and J. Colonell). AWRA 1988 Symposium on Coastal Water Resources, May 1988. Wilmington, North Carolina.

A subsurface contaminant transport model for exposure assessment from landfills (with A. Salhotra). Proceedings of 12th Annual Madison Waste Conference at University of Wisconsin at Madison, September 20-21, 1989

Natural and Anthropogenic Sources of Specific Metals and PAH Pollutants in Storm Water (with C.-C. Lee and T.D. Cooke). Poster presented at the 66th Annual Conference of the Water Environment Federation, October 3-7, 1993, Anaheim, CA.

Sensitivity Analysis of Non-Point Source Loads Assessment Using Monte Carlo Simulation (with Marco Lobascio). Paper presented at the 1993 Runoff Quantity and Quality Model Group Conference. November 8-9, 1993, Reno, Nevada.

Two Options for Disposal of Desalination Reject Water (with Louis Armstrong and Ralph Cross). Paper presented at the 1993 National Conference on Hydraulic Engineering. ASCE.

Developing and Implementing Municipal Stormwater Monitoring Plans to Meet Multiple Objectives (with T.D. Cooke and C-C. Lee). Paper presented at WEFTEC'94, the 67th Annual Conference of the Water Environment Federation. October 15-19, 1994, Chicago, Illinois.

The Value of More Frequent Cleanout of Storm Drain Inlets (with Sujatha Singh). In Watershed Protection Techniques. Vol. 1, No. 3. 1994. Ellicott City. MD.

Hydraulic and Water Quality Modeling for Saigon South Project (with Stephane Asselin and Thomas McDonald). Paper in The Built Environment Volume 10. Transactions of the Wessex Institute. 1995.

Watershed Based Source Screening Model An Analytical Tool for Watershed Management in Urban Environments (with Terrance Cooke, Sujatha Singh and Jim Scanlin). Paper presented at the Watershed '96 Conference. MOVING AHEAD TOGETHER. Technical Conference and Exposition. June 8 - 12, 1996. Baltimore, Maryland (US EPA).

Hydraulic Studies for a Large Wetland (with Stephane Asselin and Pierre-Yves Saugy). In proceeding of ASCE North American Water and Environment Congress 1996. Anaheim, California, June 22-28, 1996

Parameters for Dam Breach Analyses (with Ken Susilo and Thomas C. MacDonald). 1997, "Considerations When Selecting Parameters for Dam Breach Analysis," Dam Safety '97, Proceedings of the 1997 ASDSO Conference (CD-ROM), Pittsburgh, Pennsylvania, September 7-10, 1997.

Integrated Hydrodynamic, Sediment Transport and Water Quality Modeling of San Francisco Bay (with Vivian Lee). Presentation at 8th International Conference on Estuarine Modeling. Monterey California. November 2003.

Sediment Transport Modeling for San Francisco Bay under a Range of Hydrologic Conditions (with Vivian Lee). Paper presented at 8th International Conference on Estuarine Modeling. Monterey California. November 2003.

Peyton Slough Remediation Removes it from the Bay Area list of Toxic Hot Spots (with Francesca Demgen and Lois Autie). Poster presented at the 7th Biennial State of San Francisco Estuary Conference, Oakland,CA. October 2005.

A Kinetic Model Of Copper Cycling In San Francisco Bay. (with Brad Bessinger, Terry Cooke, Barton Forman, Vivian Lee and Louis Armstrong) In San Francisco Estuary and Watershed Science. In press.

Sensitivity And Spin Up Times Of Cohesive Sediment Transport Models Used To Simulate Bathymetric Change (with David H. Schoellhamer, Neil K. Ganju, and Megan A.Lionberger). Proceedings The 8th International Conference on Cohesive Sediment Transport. Institute of Lowland Technology, Saga University, Saga, Japan. September 2005.

Hydrodynamic Effects of Proposed Knik Arm Crossing (with J. Colonell, PE, PhD., F.ASCE, and J. Gambino, PE). Hydrologic Analysis Used in the Delta Risk Management Strategy.

Mineart, P. and Thomas MacDonald

Salt Pond Restoration: North San Francisco Bay Salt Pond Project – Salt Removal (with Seth Gentzler, PE) Presented at 2012 Headwaters to Oceans (H2O) Conference to be held May 29-31, 2012 at the Catamaran Resort Hotel, San Diego, CA.

Probabilistic Analysis of Delta Hydrology and Water Levels (with Thomas Macdonald, PhD, PE, Ram Kulkarni, PhD). Poster presented at California Water and Environmental Modeling Forum, February 23-25, 2009 Asilomar Conference Grounds, Carmel,, CA.

9. Tim Murphy

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State of California

Energy Resources

Conservation and Development Commission

In the Matter of: Application for Certification for the PUENTE POWER PROJECT	Docket No. 15-AFC-01 EXPERT DECLARATION OF TIM MURPHY REGARDING ALTERNATIVE SITES - LAND USE

I, Tim Murphy, declare as follows:

1. I am employed by AECOM, which has been retained by the Applicant to conduct certain analyses associated with the proposed Puente Power Project (Project) and am duly authorized to make this declaration.

2. I earned a Bachelor's degree in Environmental Studies from University of California at Santa Barbara in 1984. I have over 20 years of experience regarding land use planning. A copy of my current curriculum vitae is attached to this declaration as Attachment A. Based on my education, training and experience, I am qualified to provide expert testimony as to the matters addressed herein.

3. Except where stated on information and belief, the facts set forth herein are true of my own personal knowledge, and the opinions set forth herein are true and correct articulations of my opinions. If called as a witness I could and would testify competently to the facts and opinions set forth herein.

4. I prepared or participated in preparing, and am knowledgeable of the contents of Applicant's Exhibit No. 1012: Application for Certification Section 4.6, Land Use

and Agriculture (CEC TN #204219-13).

5. I have reviewed and am knowledgeable of the contents of the following documents:

- California Energy Commission (CEC) Staff Final Staff Assessment (FSA), Part 1, Section 4.2, Alternatives (portions pertaining to Land Use); and
- The statement of Ashley Golden regarding City of Oxnard land use policies filed by the City of Oxnard on January 18, 2017 (CEC TN #215421).

6. I evaluated the Ormond Beach Area Off-Site Alternative ("Ormond Beach Site") identified in the FSA (*see* FSA, p. 4.2-76) to determine the potential for development on this site to result in significant land use impacts. I specifically evaluated whether existing General Plan designations, zoning, and other land use designations were consistent with development of a power plant at the Ormond Beach Site.

7. The Ormond Beach Site address is 5980 and 6000 Arcturus Avenue. The Ormond Beach Site is composed of two parcels (APNs 2310093155 and 2310093135). The Ormond Beach Site is an approximately 13.5 to 14.5-acre undeveloped industrial site in the southeast portion of Oxnard at the intersection of Arcturus Avenue and E. McWane Boulevard.[1] The Ormond Beach Site is located approximately one-half mile inland from Ormond Beach and just east of (outside) the Coastal Zone boundary. The existing Ormond Beach Generating Station is located approximately three-quarter mile southwest of the Ormond Beach Site.

8. The General Plan designates the Ormond Beach Site as "Light Industrial." This designation is defined to include:

> "Manufacturing uses where the principal activity occurs within a building, but also permits outdoor assembly, fabrication, work/live, public services, and storage. Uses must follow high development and performance standards. Wholesale and retail sales and

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[1] The FSA identifies the total acreage as 14.5 acres; however, Ventura County Assessor records identify two parcels of 6.15 acres and 7.49 acres for a total of 13.64 acres.

services related to the principal uses permitted." (City of Oxnard 2030 General Plan at p. 3-16.)

9. The General Plan also provides that the FAR for light manufacturing designations is 0.45:1 for manufacturing, and 0.60:1 for "warehousing." (*Id*.)

10. This Light Industrial land use designation does not allow electrical generating facilities by right. Rather, this land use designation appears to be intended to apply to uses that are predominantly indoor.

11. At the same time, the General Plan does provide for a separate, special designation that specifically permits power plants: "Public Utility/Energy Facility." The Public Utility/Energy Facility land use designation is defined to include:

> [L]arge electrical generating and transmission facilities. Due to the uniqueness of these types of facilities, the development intensity is established on an individual basis. Renewable energy production facilities do not require this land use designation if they are considered accessory to an underlying use. (2030 General Plan at 3-16.)

12. Because there is a separate category that specifically allows electrical generating facilities, it is my professional opinion as an expert in land use and planning that an electrical generating facility would not be an appropriate use in the Light Industrial designation. An electrical generating facility would be a much more intensive use than the uses contemplated for the Light Industrial designation. Accordingly, it is my expert opinion that the siting of an electrical generating facility on the Ormond Beach Site, which is designated Light Industrial, would be inconsistent with the General Plan.

13. In addition, the Project would be inconsistent with the height limit for the applicable Heavy Manufacturing Planned Development (M2-PD) zone, which has a height limit of 100 feet. (Oxnard Zoning Code § 16-247.) The Project would have an approximately 188-foot tall stack, which would exceed the 100-foot height limit on the Ormond Beach Site. Accordingly, it is my expert opinion that siting the Project as currently designed on the Ormond

Beach Site, would be inconsistent with the height restrictions of the current zoning of Heavy Manufacturing Planned Development (M2-PD).

14. Based on the information and analysis described herein, it is my expert opinion that development of a power plant, such as the Project, on the Ormond Beach Site presents adverse land use impacts in the form of inconsistencies with the City of Oxnard General Plan and Zoning Code.

15. I hereby sponsor this declaration into evidence in these proceedings as Applicant's Exhibit No. 1129.

Executed on January 24, 2017, at Santa Barbara, California.

I declare under penalty of perjury of the laws of the State of California that the foregoing is true and correct.

Tim Murphy

Tim Murphy

ATTACHMENT A

AECOM

Timothy J. Murphy, AICP
Senior Environmental Planner

Technical Specialties

Environmental planning, permitting and compliance
CEQA/NEPA Document Preparation
Energy facility Proponent's Environmental Assessments
Construction compliance
Land Use project management and scheduling
NPDES water quality planning

Education

MBA, Graduate School of Management, 1991, Boston University
BA, Environmental Studies, 1984, University of California, Santa Barbara

Years of Experience

With AECOM: 8
With Other Firms: 16

Professional Affiliations

Certified Planner, American Institute of Certified Planners (AICP #147300)
Western States Petroleum Association

Mr. Murphy is a Senior Environmental Planner and environmental planning group manager with 24 years of combined private and public sector regulatory permitting and planning experience in California. He manages multidisciplinary environmental study teams, serving as Program Manager and Project Manager on major land use, energy, and infrastructure projects. Mr. Murphy is a strong asset to environmental planning and development project teams because of his extensive working knowledge of major project siting, assessment, licensing, development, and construction processes. He also is an expert on the necessary permitting steps, agency interactions, industry cultures, and project team dynamics required for successful development across several industries.

Experience

Technical Lead, Puente Power Project Application for Certification, NRG Oxnard Energy Center LLC. Managed the data collection and preparation of the Land Use section of the Application for Certification (CEQA-equivalent document) for the proposed 262 megawatt natural gas-fired generation facility in Oxnard, California. Responsibilities included identifying land uses in the vicinity of the project, determining the applicable laws, ordnances, regulations, and standards governing land use in the study area, and evaluating the potential impacts of the project.

CEQA Project Manager – Santa Barbara Ranch EIR and Transfer of Development Rights Study, Gaviota, California. Preparation of two parallel CEQA EIRs for alternative development scenarios for residential development on 1,200 acres of contiguous coastal ranch land and open space in rural Gaviota, at the historic Naples Townsite. Task lead for preparation of project descriptions, land use, recreation, policy consistency analyses, hydrology and water quality assessments, and other disciplines.

CEQA Land Use and Water Resources Task Leader - Ellwood-Devereux Open Space Management Plan and Residential Development Projects, Goleta, California. Preparation of three parallel CEQA EIRs and an Open Space and Habitat Management Plan for over 650 acres of contiguous coastal open space spanning three local jurisdictions (City of Goleta, County of Santa Barbara and University of California Santa Barbara), and associated residential home developments on sensitive coastal resource areas. Task lead for preparation of project descriptions, land use and policy consistency analyses, hydrology and water quality assessments and other disciplines.

Proponent's Environmental Assessment, Environmental Permitting and Compliance Project Manager – Gill Ranch Storage, LLC and Pacific Gas & Electric Company's Gill Ranch Gas Storage Project, Fresno and Madera Counties, California: Permitting and regulatory compliance coordinator for the successful permitting and construction of 5,000-acre gas storage field with new injection/withdrawal wells;

compression facilities; 9-mile power line; and 27-mile gas transmission pipeline through various aquatic and upland habitat and agricultural areas in the San Joaquin Valley, California. Services included siting constraints assessment; compressor permitting and design configuration feasibility study (electrical interconnection vs. onsite gas turbine); preparation of Proponent's Environmental Assessment (PEA) to the California Public Utilities Commission; Army Corps Section 404 and 401 permitting, and related surveys, technical studies and agency consultations (federal ESA through USFWS; Section 106 cultural); and California Dept. of Fish and Game Streambed Alteration Agreement and endangered species consultations.

Proponent's Environmental Assessment Project Manager – Pacific Gas & Electric Company's Sanger Substation Expansion Project: Project Manager for preparation of a PEA for submittal to the CPUC for expansion of PG&E's Sanger Substation and related transmission line upgrades and reconductoring, located near Sanger, California, southeast of Fresno. This existing substation is located in an agricultural area between the urban areas of Sanger and Fresno, and is adjacent to a major arterial road that is planned for widening. Key issues are visual resources, traffic, cultural/historic resources, and biological resources.

DOE NEPA Project Manager and Lead Author – Environmental Impact Statement for Presidential Permit – Sempra Generation's Energia Sierra Juarez Wind Project: Directed the preparation of NEPA documentation and facilitated the NEPA process for a Presidential permit under the direction of the U.S. Department of Energy (DOE). Energia Sierra Juarez U.S. Transmission, LLC (ESJ), a subsidiary of Sempra U.S. Gas and Power (Sempra), applied to the DOE for a Presidential permit for the U.S. portion of 230-kV or 500-kV electrical transmission facilities (generation-tie lines) between Sempra's proposed 1,200-MW wind turbine project in the Sierra Juarez mountains in northern Baja California and a transmission grid interconnection in southeastern San Diego County, California. NEPA key issues included desert biological resources; cultural resources; visual resource impacts of wind turbines and transmission towers; cross-border impacts to the U.S.; and cumulative impacts from other independent and interconnected electrical transmission and renewable energy projects in southeast San Diego County and Imperial County, California. The Final EIS was published in June 2012; a Record of Decision was published in July 2012; and the Presidential permit was granted in August 2012. Another critical success factor was facilitation of DOE's consultation with USFWS, as well as its cooperating agency relationships with BLM, the County of San Diego, and the California PUC.

AFC Licensing Project Manager – NRG Energy, Inc. El Segundo Power Redevelopment (ESPR) Project: Supervised all activities supporting an Application for Certification to the California Energy Commission for a 630-MW redevelopment of an existing power generating station in coastal Los Angeles County, California. Technical services included development of environmental design criteria; management of the project team through AFC preparation; presentation and defense of technical studies; project scheduling and compliance planning; offsite transmission, pipeline, and staging siting and local agency permitting; water quality management plans; and project management and services in support of AFC through the Discovery, Evidentiary and Decision phases. Included coordination and liaison with California Coastal Commission, Energy Commission, and other local, state and federal agencies.

Permitting Project Manager – Lodi Energy Center, Lodi, California: Directed the land use plans and related technical studies in support of a 47 MW gas-fired peaker plant in central California. Coordination with US Army Corps, National Marine Fisheries Service, and other resource agencies for approval of plant and associated cross-country gas pipeline through sensitive wetlands. Preparation of site-specific water quality management plans for construction and operations.

Permitting and Compliance Project Manager -- Kinder Morgan Energy Partners, LLC Liquid Fuels Bulk Terminal Expansion Project, Carson California: Managed the preparation of proponent's application materials in support of CEQA documentation and related project permitting and coordination for expansion of a refined product bulk terminal in the Long Beach/Port of Los Angeles area, Southern California.

Oil and Gas Production and Transportation Permitting Project Manager – Freeport McMoRan Oil and Gas Santa Barbara County Onshore and Offshore Permitting, Santa Barbara County, California: Responsible for comprehensive oil field permitting support including the preparation of land use plans, pipeline alignment analyses, CEQA baseline information, and U.S. Air Force environmental analysis and permitting. Program management tasks include oversight of a wide range of services, environmental documentation, and technical support at various Freeport McMoRan Oil & Gas' Central California oil fields, including assets at the Lompoc Field in Santa Barbara County, and Arroyo Grande Oil Field in San Luis Obispo County. A team of project planners and engineers support small and large repair and maintenance projects and oil field improvements, such as pipeline anomaly repairs, well workovers and drilling programs, gathering line replacements, and equipment upgrades, as well as larger capital projects and complex geotechnical and hydrogeologic evaluations.

Permitting Project Manager – Aera Energy LLC Shell Road Bridge Abutment Maintenance Project, Ventura County, California: Responsible for the preparation of applications to Ventura County, US Army Corps, CDFW, and other agencies for permitting related the Shell Road Bridge Abutment Maintenance Project. The Shell Road Bridge crosses the Ventura River and is a critical link between the east and west portions of the field. Based on the bridge structure's location in the active river channel, and sensitive biological resources in the project area, URS is assisting Aera with permit strategy and agency permitting and coordination, covering several local, state and federal agencies, with an overall strategy to enable bridge repairs in 2015.

Permitting Project Manager – ExxonMobil Exploration and Sunset Exploration, Inc. Vahevala Oil and Gas Project, Santa Barbara County, California: Responsible for the preparation of land use plans, pipeline siting analyses, CEQA baseline information, NEPA Environmental Assessment, Air Force "bed-down" analysis, and related technical studies in support of a proposed onshore-to-offshore oil and gas production facility and associated onshore processing and pipelines in northern Santa Barbara County, California. Lead coordinator with U.S. Air Force, Santa Barbara County, and California State Lands Commission. Project challenges included facility and pipeline siting within sensitive coastal habitats, and conformance with U.S. Air Force environmental and mission compatibility criteria.

Permitting and Compliance Coordinator – Venoco, Inc. South Ellwood Field Facilities Full Field Development and Line 96 Modification Projects, Coastal Santa Barbara County: Directed the preparation of offshore and onshore permit materials in support of Venoco's Full Field Development project, and subsequent planning documents and services for the Line 96 Modification project. Permitting services included project description, technical studies, and compliance plans in support of a 9-mile onshore crude oil pipeline, expansion of Platform Holly production, associated Ellwood Onshore Facility improvements, and abandonment of the existing Line 96 crude oil line in coastal Santa Barbara County, California. Coordination with California State Lands Commission, California Coastal Commission and local land use agencies during application review and CEQA process. Development and implementation of pre-construction and construction-phase permit compliance program through successful construction and operation start-up in early 2012.

NPDES Storm Water Pollution Prevention Plans, and Storm Water Management Plans, various clients: Preparation of NPDES Storm Water Pollution Prevention Plans for construction and operation of various commercial and industrial sites.

Preparation of NPDES Phase II Storm Water Management Plans for various Municipal Separate Storm Sewer Systems (MS4s) in Southern and Central California: Storm Water Management Planning tasks include review of existing information, programs, and activities; development of municipal non-point source storm water quality controls; monitoring implementation and effectiveness of compliance activities; and coordination between the lead agencies and co-permittees.

10. George Piantka

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Attorneys for Applicant

State of California

Energy Resources

Conservation and Development Commission

In the Matter of: Application for Certification for the PUENTE POWER PROJECT	Docket No. 15-AFC-01 EXPERT DECLARATION OF GEORGE PIANTKA REGARDING PROJECT ALTERNATIVES

I, George Piantka, declare as follows:

1. I am employed by NRG Energy, Inc. as Senior Director, Regulatory Environmental Services, and am duly authorized to make this declaration.

2. I earned a Master of Science in Civil/Environmental Engineering from University of Southern California in 1993 and Bachelor of Science in Chemistry from University of California, Berkeley in 1987. I have over 28 years of experience conducting permitting and environmental review for development projects. A copy of my current curriculum vitae is attached to this declaration as Attachment A. Based on my education, training and experience, I am qualified to provide expert testimony as to the matters addressed herein.

3. Except where stated on information and belief, the facts set forth herein are true of my own personal knowledge, and the opinions set forth herein are true and correct articulations of my opinions. If called as a witness, I could and would testify competently to the facts and opinions set forth herein.

4. I hereby sponsor this declaration (Applicant's Exhibit No. 1130) into evidence in these proceedings.

5. I prepared or participated in preparing, and am knowledgeable of the contents of, the following Applicant's Exhibits:

- Applicant's Exhibit No. 1004: AFC Section 2.0 Project Description (CEC TN #204219-5);
- Applicant's Exhibit No. 1023: AFC Section 5.0, Alternatives (CEC TN #204219-24);
- Applicant's Exhibit No. 1064: Project Enhancement and Refinement - Demolition of Mandalay Generating Station Units 1 and 2 (CEC TN #206698);
- Applicant's Exhibit No. 1068: Applicant's Alternative Sites Summary (CEC TN #207096); and
- Applicant's Exhibit No. 1090: Puente Power Project, Project Enhancement – Outfall Removal and Beach Restoration (CEC TN #213802).

6. The City of Oxnard analyzed five alternatives to the Project site, including the Del Norte/Fifth Street Off-Site Alternative as documented in the City's Comments Responding to CEC Issues Identification of August 10, 2015 (TN #207930).

7. The Applicant prepared an Alternatives Site Summary in December 2015 (TN #207096) that analyzed eight alternative sites and compared those sites to the Project site, including potential modifications of the Project layout.

8. The Alternatives Section of the California Energy Commission Staff's Final Staff Assessment (TN #214712) ("FSA") analyzes in detail two alternative sites for development of the Project. The two alternatives sites are referred in to in the FSA as the Ormond Beach Area Off-Site Alternative (FSA, p. 4.2-76) and the Del Norte/Fifth Street Off-Site Alternative (FSA, p. 4.2-46) and were selected for full analysis from the suite of alternative sites considered. The FSA identifies the Ormond Beach Area Off-Site Alternative as environmentally superior to the proposed Project Site (FSA, p.1-4).

9. I evaluated the alternatives analyses prepared by the City, the Applicant and CEC Staff and focused further on the Ormond Beach Area Off-Site and the Del Norte Site Alternatives to determine the potential for power plant development on these sites and to assess the potential for significant impacts associated with respective power plant development at these

sites. As summarized below, I have concluded that neither of these sites is economically feasible or environmentally superior as compared to the proposed Project site.

<u>Ormond Beach Area Off-Site Alternative</u>

10. The Ormond Beach Area Off-Site Alternative is located at 5980 and 6000 Arcturus Avenue. The site is comprised of two parcels (APNs 2310093155 and 2310093135). This alternative site presents the following environmental concerns and practical impediments to development not identified or fully analyzed in the FSA.

Biological Resources

11. Development at the Ormond Beach Off-Site Alternative may result in impacts to wetlands and other sensitive habitats, as there is a potential for hydric soils to occur at this site. Within the close vicinity of the alternative site there are several sensitive biological resources documented in the literature reviewed, including USFWS and USGS-mapped wetlands and other potentially jurisdictional water bodies, mapped ESHA, sensitive land uses, and sensitive species. The several mapped wetland features (and/or other jurisdictional water bodies) are present within 0.25-mile of the site. City of Oxnard designated Resource Protection areas are present within 0.25-mile of the site, and ESHA may also be present within 0.25-mile of the site. In addition, the site is adjacent to over 500 acres of property proposed for inclusion in the Ormond Beach Wetlands Restoration Project. These issues are addressed in more detail in the Expert Declaration of Julie Love Regarding Alternative Sites - Biological Resources, incorporated herein by reference.

Cultural Resources

12. Development at the Ormond Beach Area Off-Site Alternative may result in significant impacts to a built environment historic resource, the Ventura County Railway (VCRR). The VCRR is listed as a landmark on the Ventura County Historical Landmarks and Points of Interest, is listed on the California Register of Historical Resources, and was found to be eligible for listing on the National Register of Historic Places. The Ormond Beach Area Off-Site Alternative site contains portions of a railroad spur line connected to the VCRR, which is a contributing element to the listed historical resource. These issues are addressed in more detail

in the Expert Declaration of Jeremy Hollins Regarding Alternative Sites – Historic Resources, incorporated herein by reference.

Land Use

13. As indicated in the FSA (page 4.2-78), to approve a power generation facility at the Ormond Beach Area Off-Site Alternative, the Energy Commission would have to determine that the proposed use is in conformance with the General Plan designation, zoning and other adopted land use designations. Due to ambiguities between the City of Oxnard's General Plan and zoning designations, it cannot be concluded that development of a power generation facility at the Ormond Beach Area Off-Site Alternative would be consistent with the General Plan designation and zoning. These issues are addressed in more detail in the Expert Declaration of Tim Murphy Regarding Alternative Sites – Land Use, incorporated herein by reference.

Hazards to Aircraft Navigation

14. Naval Base Ventura County (NBVC) Point Mugu, the nearest airport, is approximately 3 miles southeast of the Ormond Beach Area Off-site Alternative. The FSA (page 4.2-110) concluded: "*It is unlikely that military aircraft would fly directly over the site. Aircraft from NBVC Point Mugu would likely fly west to the "Sea Range," a military training and testing area over the Pacific Ocean off the coast of California that stretches approximately from the United States/Mexico border at its southern end to the Cambria and San Simeon area at its northern end.* However, at the FSA Workshop held on January 10, 2017, the Naval Base expressed its concerns with impacts to aircraft stating that the Ormond Beach Area Off-site Alternative is in the direct flight path of naval aircraft. In addition, written comments submitted by Amanda Fagan, Community Planning Liaison Officer, Naval Base Ventura County (TN #213650) noted the following:

> The Ormond Beach Alternative site is located within the Approach-Departure Clearance Surface area for Runway 09/27 and within the Conical Surface area for Runway 03/21 at NBVC Point Mugu. Depending on the specific location and height of the stack, the alternative may impact the Imaginary Surfaces of the NBVC Point Mugu airfield.

15. Since aircraft tracks would be directly over the Ormond Beach Area Off-

site Alternative, potential thermal plumes from a stack located at this site could have significant impacts to aircraft. These issues are addressed in more detail in the Expert Declaration of Gary Rubenstein Regarding Alternative Sites – Aviation Hazards, incorporated herein by reference.

Water Quality and Soil Conditions

16. The FSA (page 4.2-2) states that "*The Ormond Beach Area Off-site Alternative is undeveloped, and compared to the proposed project, no temporary, demolition-related water quality impacts would occur at the alternative site.*" While there would be no demolition required at the Ormond Beach Area Off-site Alternative site, development at this site would involve excavation and grading activities that could encounter groundwater and soils that may be contaminated from historical operations at the site. In 2002, the site was investigated and showed evidence of contamination in the soil and groundwater. Contaminants included ethylbenzene, chlorinated solvents, and xylenes. The site was remediated, a No Further Action letter was issued in 2008, and as a result of the presence of hazardous substances/materials at the property (as defined in Health and Saf. Code, § 25260), the DTSC issued a Land Use Covenant to restrict use of the property and protect present or future human health. As a consequence of the Land Use Covenant, soil management activities at the site are subject to the following requirements:

- No activities that will disturb the soil at or below 5 feet below grade shall be allowed at the Property without a Soil Management Plan pre-approved by the DTSC in writing.
- Any soil brought to the surface shall be managed in accordance with all applicable provision of state and federal law.

Similar to development at the Project site, development at the Ormond Beach Area Off-Site Alternative would require development of a Soil and Groundwater Management Plan to be approved by the DTSC prior to any subsurface earthwork on the property. The Soil and Groundwater Management Plan would include a land use history of the property, including description and locations of known contamination, the nature and extent of previous investigations and remediation at the site, and procedures to be followed during earthwork to identify potentially impacted soil and groundwater and dispose of impacted material according to applicable regulations. Hence, development of a power plant on the Ormond Beach Area Off-Site Alternative site poses potential risks similar to those posed by development of the Project at the proposed site, as well as the demolition of Mandalay Units 1 and 2, which is intended to be limited to above ground removal (i.e., entail minimal ground surface). While development on the alternative site would not involve demolition activities, construction activities at the alternative site would pose risks similar to demolition and construction activities at the proposed Project site, and there is no reasonable basis for distinguishing between the two sites with respect to this issue. These issues are addressed in more detail in the Expert Declaration of Tricia Winterbauer Regarding Alternative Sites – Wastes, incorporated herein by reference.

Transmission Interconnection

17. The principal benefit of the Puente location is that it is interconnected via the Santa Clara Substation while Ormond Beach is interconnected via the Moorpark Substation. While Puente satisfies both the Santa Clara Subarea and Moorpark subarea requirements, a project at the Ormond Beach Area Off-Site Alternative can meet only Moorpark subarea requirements. Therefore, development at the proposed Project site is superior to development at the Ormond Beach Area Off-site Alternative. These issues are addressed in more detail in the Expert Declaration of Brian Theaker Regarding Alternative Sites – Transmission, incorporated herein by reference.

<u>Del Norte/Fifth Street Off-site Alternative</u>

18. The Del Norte/Fifth Street Off-site Alternative site is located in Oxnard at the intersection of S. Del Norte Boulevard and E. Fifth Street (State Highway 34). The site address is 390 S. Del Norte Boulevard near the intersection with E. Fifth Street. The site is comprised of one parcel (APN 2160160295).

Biological Resources

19. Development at the Del Norte/Fifth Street Alternative may impact potential waters of the state and wetland soils and vegetation. As stated on page 4.2-59 of the Final Staff Assessment, it is not possible to conclude whether a project at the Del Norte/Fifth Street Alternative site could be designed to avoid on-site potential waters of the state. In

addition, there is a potential for hydric soils and wetland vegetation species to occur at this site. These issues are addressed in more detail in the Expert Declaration of Julie Love Regarding Alternative Sites - Biological Resources, incorporated herein by reference).

Cultural Resources

20. Development at the Del Norte/Fifth Street Alternative site has a higher potential to impact known cultural resources than the proposed Project site. There are numerous cultural resources, both archaeological and built environment, in the vicinity of the Del Norte/Fifth Alternative that could be impacted by linear facilities that would be required for development of a power plant at this location. These issues are addressed in more detail in the Expert Declaration of Jeremy Hollins Regarding Alternative Sites – Historic Resources, incorporated herein by reference, and the Expert Declaration of Mark Hale Regarding Alternatives – Archaeological Resources, incorporated herein by reference.

Transmission Interconnection

21. Connecting to the SCE 220 kV transmission system from the Del Norte/Fifth Street Alternative site would require approximately 4 to 5 miles of newly constructed 220 kV structures and double circuit overhead transmission lines. The lines would require new right-of-way (ROW) easements based on ROW width for 220kV lines. A new 220 kV, 3 breaker ring-bus interconnection switchyard would be required at the Del Norte/Fifth Street Alternative site, which would make the project economically infeasible.

22. Similar to the Ormond Beach Area Off-site Alternative site, a project at the Del Norte/Fifth Street Alternative site would interconnect via the Moorpark Substation. While Puente satisfies both the Santa Clara Subarea and Moorpark subarea requirements, a project at the Del Norte/Fifth Street Alternative site could meet the Moorpark subarea requirements.

23. Generation interconnected at Mandalay, as would be the case for Puente at the proposed site, differs from generation interconnected at Ormond Beach, as would be the case for the Ormond Beach Area Off-Site Alternative and perhaps for the Fifth Street/Del Norte Off-Site Alternative also, in the extent to which it meets these local sub-area generation

requirements. This makes the proposed Project site preferable to the alternative sites from a reliability standpoint. Generation interconnected at Ormond Beach feeds the Moorpark substation through the transmission between Ormond Beach and Moorpark. As a result, and as shown in the CAISO's report, this generation meets only the Moorpark sub-area requirements, but not the Santa Clara sub-area requirements.[1] Generation interconnected at Mandalay feeds the Santa Clara substation through the transmission connecting Mandalay Generating Station and the Santa Clara substation and meets both the Santa Clara and Moorpark sub-area generation requirements.[2] These issues are addressed in more detail in the Expert Declaration of Brian Theaker Regarding Alternative Sites – Transmission, incorporated herein by reference.

Project Design

24. The Project would be built on a previously disturbed site within the boundaries of an existing power plant—the Mandalay Generating Station (MGS), which allows for re-purposing and re-use of existing infrastructure, including water and gas supply pipelines and transmission lines, further reducing the impacts of development on the environment. Development at the Ormond Beach Area Off-Site Alternative site and the Del Norte/Fifth Street Alternative site would require additional infrastructure and off-site linears (including natural gas line, water pipeline, storage tanks, etc.) that would make development at this site economically infeasible compared to development at the Project site. Furthermore, based on the environmental analysis of these Alternative Sites, including the biological, cultural, land use, soil, water, transmission, and aircraft hazards analysis, the Ormond Beach Area Off-Site Alternative site and the Del Norte/Fifth Street Alternative site pose significant environmental impacts that are otherwise avoided by the Project site. Finally, the evaluation, preliminary design and development of an Alternative site is a multi-year process; for example, the evaluation of the Puente site for which the Applicant has site control was substantially conducted during a 2-year period prior to the filing of the AFC in April 2015. There is not ample time to consider such an

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[1] CAISO 2017 Local Capacity Technical Analysis at page 95.
[2] *Id.*

alternative site where the Applicant does not have site control and meet the project online date in 2020.

Conclusions

25. There have been extensive alternatives analyses undertaken by the Applicant, City of Oxnard, and CEC Staff. The Applicant and the CEC conducted detailed comparisons of the Project to the respective alternatives. As outlined in this testimony and the referenced testimonies, power plant development at either the Ormond Beach Area Alternative site or the Del Norte/Fifth Street Alternative site would have significant environmental impacts. Therefore, based on the environmental analysis and the evaluation of technical and economic feasibility outlined in this and the referenced testimonies, as well as consideration of the project objectives, the Project site is clearly superior than each of the alternatives. While I disagree with CEC Staff that the Ormond Beach Area Alternative site is environmentally superior to the Project site, I do agree with CEC Staff‘s conclusion that the proposed Puente Power Project would have no significant impacts to the environment after the implementation of all feasible mitigation.

Executed on January 24, 2017, at Houston, Texas.

I declare under penalty of perjury of the laws of the State of California that the foregoing is true and correct.

George L. Piantka

ATTACHMENT A

GEORGE L. PIANTKA, PE

SR. DIRECTOR, REGULATORY ENVIRONMENTAL SERVICES – NRG ENERGY

AREAS OF EXPERTISE

- CAA: Title V/ NSR/PSD Permitting and Compliance
- CWA: NPDES Permitting and 316(b) Implementation
- Corporate Environmental Compliance/EMIS
- Corporate Financial Obligations – ARO/CapEx
- RCRA: Assessment, Remediation/Site Closure
- TSCA: PCB Assessment, Remediation
- Due Diligence, Phase I and II Site Assessments
- Water/Wastewater Management and Treatment
- Environmental/Regulatory Policy Strategy/Advocacy
- Community Outreach
- Customer Solutions

REGISTRATION

Registered Civil Engineer: California, No. C59171
1999

PROFESSIONAL HISTORY

NRG Energy, Inc., West Region, Director, 2009-Present; Regional Manager, 2007-2008

EXPERIENCE OVERVIEW

Mr. George Piantka is Senior Director of Regulatory Environmental Services for NRG Energy's West Region. Mr. Piantka has 28 years of extensive experience in multi-media permitting, compliance, remediation engineering, and water/wastewater management and treatment in the western United States, primarily in southern and northern California, for the energy, oil & gas, commercial & industrial, Port, and transportation sectors. He has focused extensively on the energy sector since 1997, serving as consultant to independent power producers and publicly owned utility, namely NRG Energy, AES, and Los Angeles Department of Water and Power. In 2007, Mr. Piantka joined NRG Energy as in-house Regional Environmental Manager before his promotion to Regional Director in 2009.

Professional Highlights at NRG:

DEVELOPMENT

Mr. Piantka has led the permitting of new generation in NRG's West Region since 2007. Among the Region's accomplishments:

- El Segundo Energy Center Project (ESEC) – project manager for the 2010 approval of the major Petition to Amend whereby NRG modified the 2005 CA Energy Commission (CEC) license by converting the project to a 560 MW, two 1x1 fast-start, air cooled, combined cycle plant. Navigated the West through the SCAQMD permitting moratorium and led, with Governmental Affairs, regulatory and legislative fixes to the permit moratorium that enabled the air district to issue the ESEC Permit to Construct and Operate.
- Carlsbad Energy Center Project (CECP) – project manager for the 2015 approval of the Application for Certification and the amendment of that was filed with the CA Energy Commission for the permitting of a 632 MW plant consisting of six LMS 100 simple cycle units. The project was successfully permitted while faced with intensive intervention and an extensive evidentiary record.
- Long Beach Emergency Repowering – permit manager for the 2007 approval of the refurbishment of the Long Beach Generating Station into a 260 MW simple cycle peaker plant, permitting through the Port of Long Beach and the local air district. This repowering project was permitted and constructed in less than 9 months.
- Puente Power Project (P3) – permit project manager for the development of a 262 MW peaking unit that is proposed to replace the Mandalay Generating Station's once through cooled steam boilers in Oxnard, CA. The application was filed in 2015. A decision is anticipated in 2017.
- Ellwood Generating Station Battery Storage – permit project manager for the development of 2 MWh battery storage project proposed at the existing Ellwood Generating Station in Santa Barbara County, CA. The project will be permitted by the City of Goleta. A decision is anticipated by end of 2016.

GEORGE L. PIANTKA, PE

SR. DIRECTOR, REGULATORY ENVIRONMENTAL SERVICES – NRG ENERGY

Essentia Management Services LLC, Long Beach, CA. Partner, 2002–2006

URS Corporation, Santa Ana and Santa Barbara, CA. Division Manager to Project Engineer/Manager, 1995–2002

PSI (as former GeoResearch), Long Beach, CA. Project Engineer/Scientist. 1992–1994

ICF Kaiser Engineers, Oakland, San Francisco, and Los Angeles, CA. Staff to Project Manager. 1988-1992

EDUCATION

University of Southern California, Los Angeles, California, M.S. Environmental Engineering, 1993

University of California, Berkeley, Berkeley, California, B.S. Chemistry, 1987

AFFILIATIONS

CA Council for Environmental and Economic Balance, Board Member

Harbor Association of Industry & Commerce (Port of Los Angeles and Long Beach), Board Member

COMPLIANCE

Mr. Piantka is responsible for oversight of the Region's compliance performance, including environmental key performance indicators, Corporate EMIS system, annual audits, Title V and NPDES permit compliance and renewals, and local agency inspections. Mr. Piantka is primary federal and state regulatory agency (EPA, ACOE, SWRCB, State Lands, Coastal Commission) liaison. Other compliance responsibilities include:

- Management of the CA Energy Commission license compliance activities.
- Management for the multi-year CA 316(b) implementation (Track 1 replacement with new generation or Track 2 intake modifications) strategy and implementation.
- Management of Renewables solar facility compliance programs; in particular Ivanpah's compliance programs, including Avian and Bat Monitoring Management Plan in accordance with BLM and CEC facility permits and associated biological opinion/conditions of certification.
- Oversight of Region's SPCC and SWPPP Programs
- Remediation lead for RCRA facility assessments, corrective action, and site closures. Closure of Conditionally Authorized wastewater treatment system in progress at one of NRG's West assets.
- Implementation of TSCA reporting, including expedited PCB remediation to meet site development timeline.

CORPORATE FINANCIAL OBLIGATIONS

Mr. Piantka is responsible for the quarterly reporting of Asset Retirement Obligations and liabilities and the development of environmental CapEx for the West Region.

WATER/WASTEWATER MANAGEMENT AND TREATMENT

As Registered Civil Engineer, Mr. Piantka serves as technical manager for Long Beach Generating Station's 1MGD wastewater treatment system, including the 2009 NPDES permitting and ongoing engineering enhancements and compliance monitoring.

ENVIRONMENTAL/REGUALTORY POLICY STRATEGY/ADVOCACY

Mr. Piantka is has served as the point for environmental and regulatory policy/rulemaking tracking, evaluation, comment and response at the local air pollution control districts to state level. Of note, Mr. Piantka worked with South Coast AQMD and elected officials as part of a resolution to challenges to SCAQMD's emission offset (tracking) programs and RECLAIM rules. Mr. Piantka has tracked federal and state 316(b) and climate change/AB 32 policy and regulations. For each, he has evaluated compliance options and associated risks. Mr. Piantka has filed comments and provided testimony directly and through our trade groups. Mr. Piantka, with the Regional Environmental Manager and Governmental Affairs has tracked AB 32/Cap-n-Trade development and pending compliance, Mandatory Reporting, and 3rd party verification. Mr. Piantka serves as a Board

Member for the California Council for Environmental and Economic Balance and the Harbor Association for Industry and Commerce – trade groups for environmental, policy, legislative, and economic interests are communicated.

COMMUNITY OUTREACH

Mr. Piantka has served as the point of contact for community outreach in the communities in which El Segundo Generating Station, Long Beach Generating Station and Encina Power Station our location. In this role, Mr. Piantka communicates status of permitting and construction of new generation projects and compliance responsibilities with civic and community interest groups. Mr. Piantka coordinates media communication around these assets and development projects with Corporate Communications. In addition, Mr. Piantka heads the West Regions econrg initiatives and the numerous community and educational programs conducted in the communities in which the West assets are located.

CUSTOMER SOLUTIONS

Mr. Piantka is a 2011 Leadership Development Program graduate – a program within NRG to promote professional growth and leadership of selected individuals. In that capacity, Mr. Piantka evaluated NRG's emerging eVgo business line and smart meter applications in coordination with NRG's retail, marketing and solutions business lines. Mr. Piantka, through existing industry relationships, helped grow customer solutions opportunities with a major entertainment company.

PROFESSIONAL HIGHTLIGHTS PRIOR TO NRG:

During Mr. Piantka's 20 year consulting career, he managed/conducted soil and groundwater investigations, environmental engineering and remediation, compliance and permitting services, and contaminated sediment studies. He has been project manager of numerous Environmental Site Assessments (ESAs), Remedial Investigations, Feasibility Studies, and Corrective Action/Remedial Action programs for public and private sector clients, with particular emphasis on Power and Port facilities. He has designed and managed numerous soil and groundwater remediation programs and has effectively negotiated site closures with regulatory agencies.

Mr. Piantka is particularly adept at managing fast tract, multi-discipline programs typical of development and due diligence projects. Mr. Piantka conducted due diligence investigations at five Southern California power plants formerly owned by Southern California Edison at the onset of deregulation in California. He has served as project manager, contributing technical lead and contributing author on several Applications for Certification filed with the California Energy Commission for Independent Power Producers and Investor Owned generation from 1999 to 2005.

Mr. Piantka's representative project experience includes:

- From 1997 through 2006, Mr. Piantka served as a Project Manager for numerous environmental programs at NRG Energy's El Segundo and Long Beach Generating Stations in Southern California. Mr. Piantka served as the Compliance Manager for the El Segundo Power Redevelopment Project, including the submittal of compliance documents intended to meet air quality, biology, cultural, geology, hazardous materials, land use, noise, paleontological, water quality, waste management, and worker safety requirements prior to and during the construction of ESEC.

For El Segundo and Long Beach Generating Stations, Mr. Piantka prepared and certified SPCC Plans. Mr. Piantka also updated and certified the SWPPPs for these generating stations.

During 1999 and 2000 for El Segundo Generating Station, Mr. Piantka served as Task Manager for Hazardous Materials and Waste Management sections of the Application for Certification (AFC) for the repower of this power plant in accordance with California Energy Commission. For the AFC, Mr. Piantka served as Project Manager for pre-construction remedial investigations, tank closures, construction dewatering, NPDES permitting and groundwater treatment. During 1997 and 1998, Mr. Piantka served as Project Manager for Additional Buyer's Due Diligence Investigations, which entailed the evaluation of environmental liabilities at the El Segundo and Long Beach Generating Stations for NRG/Dynegy.

- From 1999 to 2006, Mr. Piantka served as Project Manager for the Resource Conservation and Recovery Act (RCRA) Facility Investigations (RFI) and RCRA Closure Plans of former hazardous waste treatment units and other areas of concern under the direction of the Department of Toxic Substances Control (DTSC) for the AES' Redondo Generating Station in Redondo Beach California. During 1998, Mr. Piantka assisted with the Additional Buyer's Due Diligence Investigation, which entailed the evaluation of environmental liabilities at the Redondo Beach Generating Station for AES Corporation.

- From 1999 to 2006, Mr. Piantka served as a Project Manager on a number of initial site assessments and remedial investigations for Los Angeles Department of Water and Power (LADWP) facilities throughout California. Among the projects, Mr. Piantka conducted extensive assessments of water and sediment quality at two reservoir sites.

- From 1998 to 2000, Mr. Piantka served as Project Manager for the assessment of two Kern County power plant locations within historic oil fields and one western Arizona agricultural site for PG&E National Energy Group. Responsibilities included performing ESAs at a planned power plant site and the associated transmission and pipeline corridors. Project tasks included preparation of Phase I ESAs for the power plant site and proposed property acquisitions along transmission and pipeline corridors located on agricultural and oil field properties.

- From 1995 to 2006, Mr. Piantka has served as a Project Manager for site assessments, remedial action plans, and remedial action at more than 20 Port of Los Angeles sites. Duties included conducting an RI/FS of contaminated sediments at a former ship yard on Terminal Island and evaluating disposal options for metals-impacted sediments. Mr. Piantka also served as Project Manager for environmental tasks associated with the demolition of two contiguous Berths and the management of excavated soil and dredged sediments associated with the construction of a new wharf at a former wood (creosote) treatment plant. He prepared engineering specifications for a sheet pile wall used as a shallow groundwater barrier, designed and installed additional groundwater monitoring wells, and conducted quarterly groundwater monitoring. Mr. Piantka also prepared and implemented a remedial action plan that led to the site closure of a former underground storage tank (UST) site.

- From 2000 to 2004, Mr. Piantka served as Project Manager for the Operation & Maintenance of groundwater and soil remediation systems designed to mitigate volatile organic compounds (VOCs) in soil and groundwater and chromium in groundwater for Goodrich Corporation in Burbank, California and responded to the Cleanup and Abatement Order assigned to this site

- From 1999 to 2002, Mr. Piantka served as Project Manager for the preparation of responses to Waste Discharge Requirements (WDRs) for process and storm water runoff at the Pictsweet Mushroom Farm located in Ventura, California. As part of the response to the WDRs, Mr. Piantka designed a storm water retention basin intended to achieve zero discharge of storm water and process water at the farm.

- From 1999 to 2000, Mr. Piantka served as the engineer of record for the performance of a Safety Audit; preparation of a Process Safety Manual; and modification of the Risk Management Plan prepared for Venoco's gas process facility in Santa Barbara County, California. The documents were prepared in accordance with Venoco's California Accidental Release Program.

- From 1998 to 2001, Mr. Piantka served as Project Manager for RFI and Closure Assessments at three facilities at Naval Base Ventura County in Port Hueneme, California**.** He also served as Project Manager for an ESA of a proposed modification of natural drainage and creeks at Naval Base Ventura County, including preparation of the 404 permit for this project.

- During 1998 to 2001, Mr. Piantka managed two UST assessment and remediation projects in Santa Barbara, CA, utilizing SVE, air sparging and insitu bioremediation techniques.

- From 1995 to 1997, Mr. Piantka managed O&M of a soil and groundwater remediation system at a Mobil UST Remediation Site in Long Beach, CA**.** Responsibilities included quarterly groundwater monitoring and monthly NPDES monitoring. Cleanup objectives were met and closure was granted by the RWQCB.

- From 1995 to 1997, Mr. Piantka managed tank closure and reporting activities at several Yellow Freight facilities in California. Mr. Piantka managed interim corrective action measures at Orange and Gardena, California sites, whereby UST areas were over excavated and confirmation samples collected to confirm that clean-up goals were met.

- From 1996 to 1998, Mr. Piantka served as Project Manager for the RI of a 160,000-gallon fuel release and O&M of the LNAPL and vapor-phase remediation system along a petroleum hydrocarbon pipeline on behalf of ARCO Pipeline in Long Beach, CA. He utilized field techniques to quickly assess the stratigraphy and the extent of dissolved phase aromatic hydrocarbons in multiple saturated zones. Mr. Piantka also managed quarterly groundwater monitoring, sampling and reporting requirements for the site.

- From 1995 to 1998, Mr. Piantka served as Project Manager for subsurface investigations and free-phase removal at bulk fuel storage facility on behalf of ARCO Pipeline at the Port of Long Beach, CA. He designed and implemented the upgraded free-phase removal system to incorporate additional recover wells installed as part of site investigation activities. Mr. Piantka also managed quarterly groundwater monitoring, sampling and reporting requirements for the site.

- From 1995 to 2001, Mr. Piantka served as Project Manager for several RIs at Caltrans maintenance stations sites in central and Southern California, including Stockton, Bear Valley, and Glennville. He conducted pilot tests and screening level risk assessments as part of the evaluation of feasible remedial alternatives. Mr. Piantka also presented results to local County Health Departments and RWQCB staff and negotiated site closures, where appropriate.

- From 1995 to 2002, Mr. Piantka served as Project Manager for a 30,000-gallon spill at a service station in Lancaster, California. He managed the California State Reimbursement program and provided litigation support for the pending case against the responsible party. Mr. Piantka also worked with the client's risk management staff to implement cost recovery strategies. Total cost recovery was approximately $1.5M.

- From 1992 to 1995, Mr. Piantka managed a dozen site assessment and interim removal actions at active and closed service station sites throughout California on behalf of Unocal. At some of the sites, SVE tests were conducted and FSs prepared to evaluate remedial alternatives. Mr. Piantka also managed the UST Reimbursement programs for Unocal, which entailed the preparation and submittal of reimbursement applications for approximately 250 service station sites in California and Arizona.

- From 1990 to 1992, Mr. Piantka conducted site assessments and remediation pilot testing, and prepared RCRA closure reports for several operable units at a defense contractor facility for United Technologies, San Jose, California.

- From 1988 to 1992, Mr. Piantka managed tank removal/closure activities and conducted site assessments at several Ford Motor Company facilities in California, Oregon and Washington.

- From 1988 to 1992, Mr. Piantka managed tank removal/closure activities and conducted site assessments at active and closed United States Postal Service sites in Southern and Northern California.

- From 1988 to 1991, Mr. Piantka conducted groundwater monitoring and RIs to assess the extent of diesel- and gasoline-impacted soil and groundwater, on behalf of AC Transit, Alameda and Contra Costa Counties.

- From 1988 to 1992, Mr. Piantka has served as technical lead of Hazardous Materials and Wastes Assessments for proposed transportation improvement projects in Honolulu, HI; Oakland, CA; Sacramento, CA; and San Diego, CA.

11. Gary Rubenstein (Environmental Justice)

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Attorneys for Applicant

State of California

Energy Resources

Conservation and Development Commission

In the Matter of: Application for Certification for the PUENTE POWER PROJECT	Docket No. 15-AFC-01 EXPERT DECLARATION OF GARY RUBENSTEIN REGARDING ENVIRONMENTAL JUSTICE IN RESPONSE TO OPENING TESTIMONY OF INTERVENERS

I, Gary Rubenstein, declare as follows:

1. I am employed by Sierra Research, which has been retained by the Applicant to conduct certain analyses associated with the proposed Puente Power Project (Project) and am duly authorized to make this declaration.

2. I earned a Bachelor of Science Degree in Engineering from the California Institute of Technology in 1973. I have over 44 years of experience regarding the evaluation of air quality and public health impacts, including impacts associated with greenhouse gas emissions, and related issues in the disciplines of alternatives, biological resources (nitrogen deposition), traffic and transportation (thermal plumes), visual resources (visible plumes), energy efficiency, and environmental justice. A copy of my current curriculum vitae is attached to this declaration as Attachment A. Based on my education, training and experience, I am qualified to provide expert testimony as to the matters addressed herein.

3. Except where stated on information and belief, the facts set forth herein are true of my own personal knowledge, and the opinions set forth herein are true and correct

articulations of my opinions. If called as a witness, I could and would testify competently to the facts and opinions set forth herein and in the other Applicant's Exhibits identified herein.

4. I have reviewed the Opening Testimony of Intervenor witnesses related to the topic of Environmental Justice, and have the following responses.

5. Environmental Justice concerns arise when a proposed project (1) results in a significant environmental impact, AND (2) that significant impact falls disproportionately on disadvantaged communities.[1] However, the in-depth technical analyses prepared by both Staff and Applicant demonstrate that the Project will not result in any significant environmental impacts, either alone or on a cumulative basis. Because the Project does not result in any significant environmental impacts, no Environmental Justice issues arise.

6. Intervenors[2] assert that the Project will result in impacts to the Oxnard community that will exacerbate existing public health problems experienced by nearby residents and others who work and play in the area. However, Applicant[3,4] and Staff assessed potential Environmental Justice impacts of the proposed project and determined "that construction and operation of the Puente Power Plant would not cause significant direct, indirect, or cumulative environmental justice impacts with the inclusion of proposed conditions of certification."[5]

7. Both Applicant and Staff prepared detailed technical analyses using extremely conservative worst-case assumptions regarding operation of and emissions from the

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[1] 59 FR 32, February 16, 1994. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations. Section 1-101 (Agency Responsibilities): "identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low-income populations…"

[2] Statement of Irene Valencia on behalf of the California Environmental Justice Alliance (CEC TN #215444); Statement of Raul Lopez on behalf of the California Environmental Justice Alliance (CEC TN #215445; Statement of David Pellow, CEC TN #215448; Statement of Grace Chang on behalf of FFIERCE, CEC TN #251449

[3] AFC Section 4.10, Socioeconomics (Applicant's Exhibit No. 1016; CEC TN #204219-17).

[4] Supplemental EJ testimony (Applicant's Exhibit No. 1069; CEC TN #207111).

[5] FSA p. 1-8 (CEC TN #214712).

Project. These analyses show that the Project will not have any significant air quality or public health impacts, either individually or on a cumulative basis. Applicant's testimony describes its assessment of potential Air Quality and Public Health impacts of the Project and indicates that "the Project, as proposed, will not result in any significant direct, indirect or cumulative environmental impacts with respect to air quality, public health, or related areas."[6] Similarly, Staff's testimony concludes "that Puente, with staff's proposed mitigation, would have less than significant air quality impacts and does not expect an adverse impact to air quality or to members of the public, off-site nonresidential workers, [or] recreational users"[7] and that "using a highly conservative methodology that accounts for impacts on the most sensitive individuals in any given population…there would be no significant health impacts from the project's air emissions. Exposure to off-site nonresident workers or recreational users would be lower with correspondingly lower health risks."[8]

8. Both Applicant's and CEC Staff's analyses of potential Environmental Justice impacts followed a demographic screening approach based on 1997 CEQ[9] and 1998 U.S. EPA guidance[10] to identify the areas potentially affected by the emissions or impacts from the Project. Following the demographic screening analysis, Staff followed the steps recommended by these guidance documents, which are:

- Public outreach and involvement; and
- Consideration of potential impacts and mitigation measures and whether there would be a significant impact on an environmental justice population.

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[6] Applicant's Exhibit No. 1103: Declaration of Gary Rubenstein, p. 9 (CEC TN #215441).

[7] FSA p. 1-6 (CEC TN #214712).

[8] FSA p. 1-11 CEC TN #214712).

[9] Council on Environmental Quality, *Environmental Justice: Guidance under the National Environmental Policy Act*. December 10, 1997.

[10] U.S. EPA, *Final Guidance for Incorporating Environmental Justice Concerns in EPA's NEPA Compliance Analyses.* April 1998.

Section 4.10.2.7.3 of Applicant's socioeconomics Environmental Justice Analysis[11] evaluated whether the Project may potentially result in impacts related to Environmental Justice. The final criterion is the assessment of whether the potentially significant environmental impacts attributable to the Project would fall disproportionately on the minority or low-income populations in the project study area, based on impacts to air quality, housing, noise, public health, public service impacts, traffic, and water quality. As analyzed in the AFC, the Project would not result in significant environmental impacts accruing to any population in the study area; therefore, environmental impacts cannot accrue disproportionately to environmental justice populations (minority and/or low income) in the study area.

9. In the FSA, CEC Staff independently evaluated the potential impacts of the Projects in the areas of Air Quality, Cultural Resources, Hazardous Management, Land Use, Noise and Vibration, Public Health, Socioeconomics, Soil and Water Resources, Traffic and Transportation, Transmission Line Safety and Nuisance, Visual Resources and Waste Management, and concluded that there would be no significant impacts on Environmental Justice populations in any of these areas.[12] The FSA concludes that:

> "construction and operation of the Puente Power Project … would not cause significant direct, indirect, or cumulative environmental justice impacts with the inclusion of proposed conditions of certification (see technical sections). Staff also concludes that project impacts would not disproportionately affect the environmental justice population."[13]

Because all potential health and safety and environmental impacts from the Project will be mitigated to less than significant levels for all affected populations, including minority

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[11] AFC Section 4.10, Socioeconomics (Applicant's Exhibit No. 1016; CEC TN #204219-17).

[12] FSA Section 4.5 (CEC TN #214712).

[13] FSA, Section 4.5, p. 4.5-1 (CEC TN #214712).

populations, the proposed project will not cause or contribute to disproportionate impacts on minority populations.

10. Intervenors assert that the CEC Staff's finding of no significant impacts relies on emission reductions from elsewhere in the county, and that these offsets do not effectively mitigate the emissions from the proposed project.[14] On the contrary, the offsets and mitigation that will be provided for the Project will be effective in mitigating potential local and regional air quality and public health impacts of the Project. In fact, emission offsets are a well-established option for satisfying CEQA mitigation requirements in California.

11. VCAPCD's offset requirements are intended to address potential regional air quality impacts, and not localized impacts. Localized impacts are addressed through requirements for Best Available Control Technology, an air quality impact analysis, and a screening health risk assessment. The Project satisfied all District requirements related to potential localized impacts. In addition, the Applicant will provide NOx and VOC ERCs to offset potential increases in these pollutants from the project at a ratio of 1.3 to 1.[15] A large portion of the NOx ERC package proposed for the Project is associated with ERC Certificate Number 1092 (current NOx ERCs amount of approximately 23 tons/year). These NOx ERCs were issued for NOx emission reductions associated with the replacement of agricultural pump engines in the Pleasant Valley Water District which is located on the Oxnard Plain.[16] Ozone and $PM_{2.5}$ are regional, not local, pollutants, meaning that local concentrations of these pollutants result from emissions sources throughout the region rather than from individual, local emissions sources.[17]

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[14] Statement of David Pellow (CEC TN #215448); Statement of Grace Chang on behalf of FFIERCE (CEC TN #251449).

[15] FDOC (p. 26 of 376 in PDF) (CEC TN #214005).

[16] Applicant's Exhibit No. 1085; CEC TN 213482, Response 26, p. 12.

[17] Applicant's Exhibit No. 1007; CEC TN #204219-8, Section 4.1.4.1.1 [AFC]; FSA pp. 4.1-61-62 TN 214712.

In addition to the offsets provided to fulfill District requirements for regional impacts, impacts will be further mitigated through funding provided to the California Air Resources Board (CARB) Carl Moyer Program.[18] The Applicant has agreed to Staff's condition of certification AQ-SC9**,** which would ensure that impacts of emissions of particulate matter and its precursors (such as SO_2) would be adequately mitigated.[19]

12. Intervenors assert that the census tracts surrounding the Project have high absolute and relative CES scores.[20] However, CalEnviroScreen was developed for a specific purpose and has certain limitations that make it impossible to draw meaningful conclusions from these scores. In its CES user guide OEHHA specifically states that while the tool's output provides a relative ranking of communities based on a selected group of available data sets through the use of a summary score, <u>the score is not an expression of health risk</u> and CES scores <u>are not intended to be used as health risk assessments for a specific area or site</u>. OEHHA further states that CES results do not provide a basis for determining when differences between scores are significant in relation to human health.[21] Therefore, a relatively high CES score does not mean that residents within the area are exposed to high health risks.

13. The exposure indicators for ozone and $PM_{2.5}$ are two of the 20 components used to develop the census tract-specific CES scores in CES 3.0. Individual component scores are combined by the model to produce an overall CES score, so the scores for each individual indicator influence the overall score. As an example of how the individual component scores may be misleading, Applicant compared the CES ozone and $PM_{2.5}$ exposure indicator results from CES 3.0 for the Project Area with the monitored background concentrations and ambient air quality standards. The results of this comparison are shown in

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[18] Applicant's Exhibit No. 1062; CEC TN #206614, DR 62.

[19] FSA, p, 4.1-53 (CEC TN #214712).

[20] CEJA, Cervas Statement (CEC TN #215443)

[21] OEHHA, Update to the California Communities Environmental Health Screening Tool, CalEnviroScreen 3.0 (CES 3.0), January 2017, p. 37.

the table below.

Summary of CalEnviroScreen Ozone and $PM_{2.5}$ Pollution Burden Indicator Results

P3 Project Area (Census Tract 6111002905)

	Ozone (8-hour average)		$PM_{2.5}$ (annual mean)	
	Concentration	Percentile	Concentration	Percentile
CES3.0[a]	0.04 ppm	40	9.54 µg/m^3	41
Federal Standard	0.070 ppm		12.0 µg/m^3	
State Standard	0.070 ppm		12 µg/m^3	
Note: a. Data for CY 2012-2014				

In CES 3.0, the Project Area is ranked in the 40th percentile for 8-hour average ozone concentrations and in the 41st percentile for annual $PM_{2.5}$ concentrations. These scores suggest that the background concentrations are relatively high, since 40 percent of California census tracts have lower background concentrations than those measured in the project area. However, a comparison of the actual monitored ozone and $PM_{2.5}$ concentrations in the project area with the ambient air quality standards shows that the monitored values are well below the standards. The standards are set at levels which, "allowing an adequate margin of safety, are requisite to protect the public health."[22] The federal standards are intended to protect the health of "sensitive" populations such as asthmatics, children, and the elderly.[23] Therefore, monitored concentrations below these health-protective levels do not, by definition, pose a threat to public health. However, by ranking the Project Area as being in the 40th percentile for these pollution indicators, CES creates the impression that the pollution in these areas is relatively high.

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[22] 42 USC §7409 (b)(1)

[23] U.S. EPA, "Criteria Air Pollutants, NAAQS Table," *https://www.epa.gov/criteria-air-pollutants/naaqs-table*

14. As described in the FSA, all departments, boards, commissions, conservancies and special programs of the Resources Agency, including the CEC, must consider Environmental Justice in their decision-making process if their actions have an impact on the environment, environmental laws, or policies.[24] CES could be used, along with other information, to determine the relative populations of low-income persons in various census tracts within 6 miles of the project area, and CES scores could be used, along with other information, to characterize areas surrounding the project in terms of existing pollution burdens as one element of a cumulative impacts assessment. However, as stated by OEHHA, CES scores are not an expression of health risk, nor is there a basis for determining when differences between scores are significant.

15. I hereby sponsor this declaration into evidence in these proceedings as Applicant's Exhibit No. 1132.

Executed on January 24, 2017, at Sacramento, California.

I declare under penalty of perjury of the laws of the State of California that the foregoing is true and correct.

Gary Rubenstein

Gary Rubenstein

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[24] FSA p. 4.5-2, TN 214712

ATTACHMENT A

sierra
research

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Résumé

Gary S. Rubenstein

Education

1973, B.S., Engineering, California Institute of Technology

Professional Experience

8/81 to present — Senior Partner
Sierra Research

As one of the founding partners of Sierra Research, responsibilities include project management and technical and strategy analysis in all aspects of air quality planning and strategy development; project licensing and impact analysis; emission control system design and evaluation; rulemaking development and analysis; vehicle inspection and maintenance program design and analysis; and automotive emission control design, from the initial design of control systems to the development of methods to assess their performance in customer service. As the Partner principally responsible for Sierra Research's activities related to stationary sources, he has supervised the preparation of control technology assessments, environmental impact reports and permit applications for numerous industrial and other development projects.

While with Sierra, Mr. Rubenstein has managed and worked on numerous projects, including preparation of nonattainment plans; preparation and review of emission inventories and control strategies; preparation of the air quality portions of environmental review documents for controversial transportation, energy, mineral industry and landfill projects; preparation of screening health risk assessments and supporting analyses; and the development of air quality mitigation programs. Mr. Rubenstein has managed the preparation of air quality licensing applications for over 18,000 megawatts of generating capacity before the California Energy Commission, and has managed air quality analyses for over 30,000 megawatts of generating capacity in a variety of jurisdictions.

Mr. Rubenstein and his colleagues at Sierra have followed literature related to climate change and the control of greenhouse gas emissions since the early 1990s. The firm's work has focused on understanding the scientific, legal and regulatory basis for the regulation of greenhouse emissions by various jurisdictions in the United States, and on the evaluation of the costs and environmental impacts of alternative regulatory approaches for controlling greenhouse gas emissions.

Mr. Rubenstein has presented testimony and served as a technical expert witness before numerous state and local regulatory agencies, including the U.S. Environmental Protection Agency, California State Legislative Committees, the California Air Resources Board, the California Energy Commission, the California Public Utilities Commission, numerous California air pollution control districts, the Connecticut Department of Environmental Protection, the Hawaii Department of Health, and the Alabama Department of Environmental Management. Mr. Rubenstein has also served as a technical expert on behalf of the California Attorney General and Alaska Department of Law, and has provided expert witness testimony in a variety of administrative and judicial proceedings.

6/79 to 7/81 Deputy Executive Officer
California Air Resources Board

Responsibilities included policy management and oversight of the technical work of ARB divisions employing over 200 professional engineers and specialists; final review of technical reports and correspondence prepared by all ARB divisions prior to publication, covering such diverse areas as motor vehicle emission standards and test procedures, motor vehicle inspection and maintenance, and air pollution control techniques for sources such as oil refineries, power plants, gasoline service stations and dry cleaners; review of program budget and planning efforts of all technical divisions at ARB; policy-level negotiations with officials from other government agencies and private industry regarding technical, legal, and legislative issues before the Board; representing the California Air Resources Board in public meetings and hearings before the California State Legislature, the California Energy Commission, the California Public Utilities Commission, the Environmental Protection Agency, numerous local government agencies, and the news media on a broad range of technical and policy issues; and assisting in the supervision of over 500 full-time employees through the use of standard principles of personnel management and motivation, organization, and problem solving.

7/78 – 7/79 Chief, Energy Project Evaluation Branch
Stationary Source Control Division
California Air Resources Board

Responsibilities included supervision of ten professional engineers and specialists, including the use of personnel management and motivation techniques; preparation of a major overhaul of ARB's industrial source siting policy; conduct of negotiations with local officials and project proponents on requirements and conditions for siting such diverse projects as offshore oil production platforms, coal-fired power plants, marine terminal facilities, and almond-hull burning boilers.

During this period, Mr. Rubenstein was responsible for the successful negotiation of California's first air pollution permit agreements governing a liquefied natural gas terminal, coal-fired power plant, and several offshore oil production facilities.

10/73 to 7/78 Staff Engineer
Vehicle Emissions Control Division
California Air Resources Board

Responsibilities included design and execution of test programs to evaluate the deterioration of emissions on new and low-mileage vehicles; detailed analysis of the effect of California emission standards on model availability and fuel economy; analysis of proposed federal emission control regulations and California legislation; evaluation of the cost-effectiveness of vehicle emission control strategies; evaluation of vehicle inspection and maintenance programs, and preparation of associated legislation, regulations and budgets; and preparation of detailed legal and technical regulations regarding all aspects of motor vehicle pollution control. Further duties included preparation and presentation of testimony before the California Legislature and the U.S. Environmental Protection Agency; preparation of division and project budgets; and creation and supervision of the Special Projects Section, a small group of highly trained and motivated individuals responsible for policy proposals and support in both technical and administrative areas (May 1976 to July 1978).

Credentials and Memberships

Air & Waste Management Association (Past Chair, Board of Directors, Golden West Section; Past Chair, Board of Directors, Mother Lode Chapter)

American Society of Mechanical Engineers

Qualified Environmental Professional, Institute of Professional Environmental Practice, 1994

Selected Publications (Author or Co-Author)

"Multipollutant Approaches to Regulation," presentation at the California Council for Environmental and Economic Balance 2016 Summer Issues Seminar, July 11, 2016.

"Air Quality and Public Health," presentation at the California Council for Environmental and Economic Balance 2016 Summer Issues Seminar, July 13, 2016.

"Overview of the California Environmental Quality Act," presentation for private client, June 2016.

"The Efficacy of Greenhouse Gas Emission Caps at Local Refineries," presentation to the Bay Area Air Quality Management District Advisory Council, April 25, 2016.

“Fundaments of Air Quality Planning and Regulation,” presentation to the Jiangsu Environmental Protection Department, October 20, 2015.

“Carbon Pollution Standards for New, Modified and Reconstructed Power Plants – Final Rule and Impacts,” presentation for private clients, August 27, 2015.

“Understanding the Supreme Court’s MATS Ruling,” presentation for private clients, July 15, 2015.

“OEHHA’s New Hot Spots Exposure and Assessment Guidelines,” prepared for private client, October 30, 2014.

“Diesel Particulate Matter Regulation and Health Impacts,” presentation at the 2012 Railroad Environmental Conference on October 16, 2012, in Champagne-Urbana, Illinois.

“Using Screening Tools to Identify Priority Communities,” presentation at the California Council for Environmental and Economic Balance 2012 Summer Issues Seminar on July 16, 2012, at Squaw Valley, California.

“Slogging Through the Modeling Maze: New National Ambient Air Quality Standards for NO_2, SO_2 and $PM_{2.5}$,” presentation to the Air & Waste Management Association on February 12, 2012, in Sacramento, California.

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12. Gary Rubenstein

(Alternative Sites – Aviation Hazards)

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State of California

Energy Resources

Conservation and Development Commission

In the Matter of: Application for Certification for the PUENTE POWER PROJECT	Docket No. 15-AFC-01 EXPERT DECLARATION OF GARY RUBENSTEIN REGARDING ALTERNATIVE SITES – AVIATION HAZARDS

I, Gary Rubenstein, declare as follows:

1. I am employed by Sierra Research, which has been retained by the Applicant to conduct certain analyses associated with the proposed Puente Power Project (Project) and am duly authorized to make this declaration.

2. I earned a Bachelor of Science Degree in Engineering from the California Institute of Technology in 1973. I have over 44 years of experience regarding air quality modeling, including modeling of thermal plumes from industrial sources and evaluation of their impacts. A copy of my current curriculum vitae is attached to this declaration as Attachment A. Based on my education, training and experience, I am qualified to provide expert testimony as to the matters addressed herein.

3. Except where stated on information and belief, the facts set forth herein are true of my own personal knowledge, and the opinions set forth herein are true and correct articulations of my opinions. If called as a witness, I could and would testify competently to the facts and opinions set forth herein.

4. I have reviewed and am knowledgeable of the contents of the following documents:

- California Energy Commission (CEC) Staff Final Staff Assessment (FSA), Part 1, Section 4.12, Traffic and Transportation (portions pertaining to visible and thermal plumes, including Appendices TT-1, TT-2 and TT-3) (CEC TN #214712); and
- CEC FSA, Part 1, Section 4.2, Alternatives (portions pertaining to visible and thermal plumes) (CEC TN #214712).

5. In the FSA, Section 4.12, Traffic and Transportation, CEC Staff concludes that with implementation of proposed Conditions of Certification TRANS-6 and TRANS-7, any potential aviation impacts associated with the Project will be reduced to a "less than significant level." (FSA, p. 4.12-21). I concur with this conclusion.

6. In the FSA, Part 1, Section 4.2, Alternatives, CEC Staff concludes that although potential aviation impacts associated with the Project are less than significant, "the potential risk associated with this impact [thermal plumes] for the [Ormond Beach] offsite alternative is less than Puente and the impact conclusion is less than significant." (FSA, p. 4.2-111). Thus, according to the FSA, both the proposed Project site and the Ormond Beach Area Off-Site Alternative site would pose a less than significant risk to aviation safety, but the risk associated with the alternative site is somewhat less than the risk associated with the Project site.

7. The nature of the thermal plume modeling performed by CEC Staff is such that the results are relatively independent of location specific characteristics within the same general area. In other words, one would expect the results to be similar for locations in the same general area, such as the Project site and the Ormond Beach Area Off-Site Alternative and, in fact, in its evaluation of the potential risks associated with thermal plumes at the alternative sites, Staff did not make any adjustments to the thermal plume modeling conducted for the Project at its proposed location. Thus, the comparison of the risk associated with two sites in relatively close proximity to one another is entirely a function of the relative expected occurrence of air traffic over the two sites.

8. Consistent with the forgoing, CEC Staff's conclusion that potential

impacts associated with the Ormond Beach Area Off-Site Alternative were somewhat less than those associated with the proposed Project site are based on Staff's conclusion that there would be less potential for low altitude air traffic over the alternative site relative to the Project site. Specifically, Staff concluded that "aircraft and pilot safety impacts from this off-site alternative would be less than Puente and less than significant, given the greater distances of airports from the Ormond Beach Area Off-site Alternative compared to Puente (less than 2 miles from the Oxnard Airport), making overflight of the alternative site at low altitudes less likely." (FSA, p. 4.2-110).

9. CEC Staff's conclusion that overflight of the Ormond Beach Area Off-site Alternative would be less than that associated with the Project site was based, in part, on its understanding that military aircraft based at Naval Base Ventura County (NBVC), which is approximately 3 miles southeast of the Ormond Beach Area Off-site Alternative, would be unlikely to fly directly over the site. (FSA, p. 4.2-110).

10. However, written comments submitted by Amanda Fagan, Community Planning Liaison Officer, NBVC (TN #213650) contradict CEC Staff's conclusion as follows:

> The Ormond Beach Alternative site is located within the Approach-Departure Clearance Surface area for Runway 09/27 and within the Conical Surface area for Runway 03/21 at NBVC Point Mugu. Depending on the specific location and height of the stack, the alternative may impact the Imaginary Surfaces of the NBVC Point Mugu airfield. In addition, the Ormond Beach Alternative location raises potential concerns related to lighting, dust, smoke and steam, and potential impacts to special-status species at NBVC Point Mugu. Bright lights and lighting that is not downward directed in the vicinity of the airfield can impair pilot vision, especially at night. Land uses that generate sources of dust, smoke and steam in the airfield vicinity could obstruct pilot vision during takeoff, landing or other periods of low-altitude flight.

The NBVC comments go on to question Staff's conclusion that potential impacts from thermal plumes on aircraft and pilot safety for the Ormond Beach Alternative are less than those associated with the Project site, which the comments note is outside of the Imaginary Surfaces for the NBVC Point Mugu airfield. Ms. Fagan reiterated these points in verbal comments provided at the FSA Workshop held on January 10, 2017.

11. Based on the NBVC comments indicating the location of flight operations at NBVC Point Mugu airfield, and additional information provided by NBVC in their comment letter and at the FSA Workshop, it is my expert opinion that CEC Staff's conclusion that thermal plume impacts at the Ormond Beach Area Off-Site Alternative would be less than those associated with the proposed Project site is incorrect. To the contrary, based on the NBVC comments, it appears that thermal plume impacts at the alternative site would be greater than those at the proposed Project site, although an assessment of the significance of those impacts would need to reflect both the physical plume parameters (as determined at the Project site) and the location of the Imaginary Surfaces of the NBVC Point Mugu airfield.

12. I hereby sponsor this declaration into evidence in these proceedings as Applicant's Exhibit No. 1133.

Executed on January 24, 2017, at Sacramento, California.

I declare under penalty of perjury of the laws of the State of California that the foregoing is true and correct.

Gary Rubenstein

Gary Rubenstein

ATTACHMENT A

sierra
research

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Résumé

Gary S. Rubenstein

Education

1973, B.S., Engineering, California Institute of Technology

Professional Experience

8/81 to present Senior Partner
Sierra Research

As one of the founding partners of Sierra Research, responsibilities include project management and technical and strategy analysis in all aspects of air quality planning and strategy development; project licensing and impact analysis; emission control system design and evaluation; rulemaking development and analysis; vehicle inspection and maintenance program design and analysis; and automotive emission control design, from the initial design of control systems to the development of methods to assess their performance in customer service. As the Partner principally responsible for Sierra Research's activities related to stationary sources, he has supervised the preparation of control technology assessments, environmental impact reports and permit applications for numerous industrial and other development projects.

While with Sierra, Mr. Rubenstein has managed and worked on numerous projects, including preparation of nonattainment plans; preparation and review of emission inventories and control strategies; preparation of the air quality portions of environmental review documents for controversial transportation, energy, mineral industry and landfill projects; preparation of screening health risk assessments and supporting analyses; and the development of air quality mitigation programs. Mr. Rubenstein has managed the preparation of air quality licensing applications for over 18,000 megawatts of generating capacity before the California Energy Commission, and has managed air quality analyses for over 30,000 megawatts of generating capacity in a variety of jurisdictions.

Mr. Rubenstein and his colleagues at Sierra have followed literature related to climate change and the control of greenhouse gas emissions since the early 1990s. The firm's work has focused on understanding the scientific, legal and regulatory basis for the regulation of greenhouse emissions by various jurisdictions in the United States, and on the evaluation of the costs and environmental impacts of alternative regulatory approaches for controlling greenhouse gas emissions.

Mr. Rubenstein has presented testimony and served as a technical expert witness before numerous state and local regulatory agencies, including the U.S. Environmental Protection Agency, California State Legislative Committees, the California Air Resources Board, the California Energy Commission, the California Public Utilities Commission, numerous California air pollution control districts, the Connecticut Department of Environmental Protection, the Hawaii Department of Health, and the Alabama Department of Environmental Management. Mr. Rubenstein has also served as a technical expert on behalf of the California Attorney General and Alaska Department of Law, and has provided expert witness testimony in a variety of administrative and judicial proceedings.

6/79 to 7/81 Deputy Executive Officer
California Air Resources Board

Responsibilities included policy management and oversight of the technical work of ARB divisions employing over 200 professional engineers and specialists; final review of technical reports and correspondence prepared by all ARB divisions prior to publication, covering such diverse areas as motor vehicle emission standards and test procedures, motor vehicle inspection and maintenance, and air pollution control techniques for sources such as oil refineries, power plants, gasoline service stations and dry cleaners; review of program budget and planning efforts of all technical divisions at ARB; policy-level negotiations with officials from other government agencies and private industry regarding technical, legal, and legislative issues before the Board; representing the California Air Resources Board in public meetings and hearings before the California State Legislature, the California Energy Commission, the California Public Utilities Commission, the Environmental Protection Agency, numerous local government agencies, and the news media on a broad range of technical and policy issues; and assisting in the supervision of over 500 full-time employees through the use of standard principles of personnel management and motivation, organization, and problem solving.

7/78 – 7/79 Chief, Energy Project Evaluation Branch
Stationary Source Control Division
California Air Resources Board

Responsibilities included supervision of ten professional engineers and specialists, including the use of personnel management and motivation techniques; preparation of a major overhaul of ARB’s industrial source siting policy; conduct of negotiations with local officials and project proponents on requirements and conditions for siting such diverse projects as offshore oil production platforms, coal-fired power plants, marine terminal facilities, and almond-hull burning boilers.

During this period, Mr. Rubenstein was responsible for the successful negotiation of California’s first air pollution permit agreements governing a liquefied natural gas terminal, coal-fired power plant, and several offshore oil production facilities.

10/73 to 7/78 Staff Engineer
Vehicle Emissions Control Division
California Air Resources Board

Responsibilities included design and execution of test programs to evaluate the deterioration of emissions on new and low-mileage vehicles; detailed analysis of the effect of California emission standards on model availability and fuel economy; analysis of proposed federal emission control regulations and California legislation; evaluation of the cost-effectiveness of vehicle emission control strategies; evaluation of vehicle inspection and maintenance programs, and preparation of associated legislation, regulations and budgets; and preparation of detailed legal and technical regulations regarding all aspects of motor vehicle pollution control. Further duties included preparation and presentation of testimony before the California Legislature and the U.S. Environmental Protection Agency; preparation of division and project budgets; and creation and supervision of the Special Projects Section, a small group of highly trained and motivated individuals responsible for policy proposals and support in both technical and administrative areas (May 1976 to July 1978).

Credentials and Memberships

Air & Waste Management Association (Past Chair, Board of Directors, Golden West Section; Past Chair, Board of Directors, Mother Lode Chapter)

American Society of Mechanical Engineers

Qualified Environmental Professional, Institute of Professional Environmental Practice, 1994

Selected Publications (Author or Co-Author)

"Multipollutant Approaches to Regulation," presentation at the California Council for Environmental and Economic Balance 2016 Summer Issues Seminar, July 11, 2016.

"Air Quality and Public Health," presentation at the California Council for Environmental and Economic Balance 2016 Summer Issues Seminar, July 13, 2016.

"Overview of the California Environmental Quality Act," presentation for private client, June 2016.

"The Efficacy of Greenhouse Gas Emission Caps at Local Refineries," presentation to the Bay Area Air Quality Management District Advisory Council, April 25, 2016.

"Fundaments of Air Quality Planning and Regulation," presentation to the Jiangsu Environmental Protection Department, October 20, 2015.

"Carbon Pollution Standards for New, Modified and Reconstructed Power Plants – Final Rule and Impacts," presentation for private clients, August 27, 2015.

"Understanding the Supreme Court's MATS Ruling," presentation for private clients, July 15, 2015.

"OEHHA's New Hot Spots Exposure and Assessment Guidelines," prepared for private client, October 30, 2014.

"Diesel Particulate Matter Regulation and Health Impacts," presentation at the 2012 Railroad Environmental Conference on October 16, 2012, in Champagne-Urbana, Illinois.

"Using Screening Tools to Identify Priority Communities," presentation at the California Council for Environmental and Economic Balance 2012 Summer Issues Seminar on July 16, 2012, at Squaw Valley, California.

"Slogging Through the Modeling Maze: New National Ambient Air Quality Standards for NO_2, SO_2 and $PM_{2.5}$," presentation to the Air & Waste Management Association on February 12, 2012, in Sacramento, California.

"Climate Change Regulation and Environmental Justice," presentation at the California Council for Environmental and Economic Balance 2011 Summer Issues Seminar on July 11, 2011, at Squaw Valley, California.

"EPA Greenhouse Gas Tailoring Rule," presentation to the Air & Waste Management Association on February 16, 2011, at Bakersfield, California.

"Non-Traditional ERCs – Giving Credit Where Credit is Due," presentation to the California Desert Air Working Group on November 17, 2010, at Laughlin, Nevada.

"Sensitivity and Vulnerability: Community Health Factors as Part of Environmental Decision Making," presentation at the California Council for Environmental and Economic Balance 2010 Summer Issues Seminar on July 19, 2010, at Squaw Valley, California.

"Evaluation of CTM-039 Dilution Method for Measuring PM_{10}/$PM_{2.5}$ Emissions from Gas-Fired Combustion Turbines," August 20, 2009.

"Application of SCR to Small Sources: A Case Study" presentation to the Air & Waste Management Association on January 29, 2009, in Diamond Bar, California.

"Dealing with the Scarcity of PM Offsets," presentation to Law Seminars International: Air Quality Regulation in California on April 15, 2008, in Los Angeles, CA.

"Field Demonstration of a Dilution-Based Particulate Measurement System," presentation to Stationary Source Sampling and Analysis for Air Pollutants on March 5, 2008, in San Diego, CA.

"The California Global Warming Solutions Act of 2006 – Implementation Considerations," presentation to Law Seminars International: Energy in California 2007 on September 17, 2007, in San Francisco, CA.

"Preparing for and Conducting Air Quality Compliance Audits," presentation to California Desert Air Working Group on October 19, 2006, in Big Bear Lake, CA.

"Test Results from Sugar Cane Bagasse and High Fiber Cane Co-fired with Fossil Fuels," Biomass and Bioenergy, Vol. 30, Issue 6. pp. 565-574. June 2006.

"Gas Turbine Particulate Matter Emissions – Update," Presentation to ASME/EIGTI Turbo Exp. on June 9, 2005 in Reno, NV.

"Gas Turbine Startup Emissions," Presentation to ASME/IGTI Turbo Expo on June 9, 2005 in Reno, NV.

"Gas Turbine Particulate Matter Emissions – Update," Presentation to ASME/IGTI Turbo Expo on June 18, 2003 in Atlanta, GA.

"Sources of Uncertainty When Measuring Particulate Matter Emissions from Natural Gas-Fired Combustion Turbines," presentation to Air & Waste Management Association on March 30, 2001 in San Diego, CA.

"An Analysis of the Effect on Emissions of Allowing Drive-Thru Service Lanes," Sierra Research Report No. SR97-11-01, prepared for California Business Properties Association, November 10, 1997.

"Searles Valley Air Quality Study (SVAQS) Final Report," Sierra Research Report No. SR94-02-01, prepared for North American Chemical Company, February 1994.

"Regulatory Strategies for Reducing Emissions from Marine Vessels in California Waters," Sierra Research Report No. SR91-10-01, prepared for the California Air Resources Board, October 4, 1991.

"An Analysis of the Effect on Emissions of Eliminating Drive-Thru Services Lanes," Sierra Research Report No. SR91-07-03, prepared for California Restaurant Association, July 25, 1991.

“Development of the CALIMFAC California I/M Benefits Model,” Sierra Research Report No. SR-91-01-01, prepared for the California Air Resources Board, Agreement No. A6-173-64, January 1991.

“Criteria Pollutant Emission Inventory for the Coachella Valley Study Area,” Sierra Research Report No. SR90-11-01, prepared for South Coast Air Quality Management District, November 1990.

“User’s Guide to the CALIMFAC California I/M Benefits Model,” Prepared for the California Air Resources Board, May 1990.

“Potential Emissions and Air Quality Effects of Alternative Fuels – Final Report,” Sierra Research Report No. SR89-03-04, prepared for Western States Petroleum Association, March 28, 1989.

“Interprecursor Offset Ratios for Ozone in the Searles Valley,” Sierra Research Report No. SR89-03-02, prepared for Kerr-McGee Chemical Company, March 17, 1989.

“An Assessment of the Quality of California’s Air Pollution Emissions Inventory,” Sierra Research Report No. SR88-05-01, prepared for Western Oil and Gas Association, May 1988.

“Trends in Visibility-Related Emissions Affecting the R-2508 Restricted Airspace,” Sierra Research Report No. SR88-05-02, prepared for Western Oil and Gas Association, May 1988.

“Volume I, Executive Summary: Impacts of Air Quality Regulations on Visibility-Related Emissions in the California R-2508 Restricted Airspace,” Sierra Research Report No. SR88-03-02, prepared for Western Oil and Gas Association, March 1988.

“Volume II, Determination of California Air Basins Which Can Affect Visibility in the R-2508 Restricted Airspace,” Sierra Research Report No. SR88-03-03, prepared for Western Oil and Gas Association, March 1988.

“Air Quality Impact Analysis for the Soledad Biomass Resource Recovery Project,” Sierra Research Report No. SR87-10-01, prepared for Western Forest Power Corp., October 1987.

“Air Quality Impact Analysis for the Honey Lake Biomass Power Plant Project,” Sierra Research Report No. SR87-05-01, prepared for GeoProducts-Zurn/NEPCO, May 22, 1987.

“1986 Update to the Kern County Nonattainment Area Plan,” Sierra Research Report No. SR86-03-01, prepared for Kern County Air Pollution Control District and Kern Council of Governments, March 1986.

"An Analysis of Test Results on Grancor Pollution Control Devices for Automotive Retrofit Programs," Sierra Research Report No. SR85-09-01, prepared for Grancor, September 1985.

"Temperature Correction Factors for California's Motor Vehicle Emissions Model," Sierra Research Report No. SR85-06-01, prepared for the California Air Resources Board, June 1985.

"Critique of the EPA I/M Benefits Model for 1980 and Older Model Cars," Sierra Research Report No. SR85-06-02, prepared for the California Air Resources Board, June 1985.

"Emission Factors for 1980 and Later Model Year California Passenger Cars and Light-Duty Trucks," Sierra Research Report No. SR85-06-03, prepared for the California Air Resources Board, June 1985.

"Technology Assessment for Light-Duty Vehicle Compliance with a 0.4g/m NOx Standard," Sierra Research Report No. SR85-06-04, prepared for the California Air Resources Board, June 1985.

"Development of California's I/M Credits Model," Sierra Research Report No. SR85-06-06, prepared for the California Air Resources Board, June 1985.

"A Comparison of Refueling Emissions Control with Onboard and Stage II Systems," SAE Technical Paper No. 851204, Society of Automotive Engineers, May 1985.

"Evaluation of Automotive CO Emissions Control Techniques at Low Temperatures (METFAC Report 2)," Sierra Research Report No. SR84-11-01, prepared for Alaska Department of Environmental Conservation, November 1984.

"Critical Metal Consumption in Automotive Catalysts – Trends and Alternatives," Sierra Research Report No. SR83-12-01, prepared for Congress of the United States, Office of Technology Assessment, December 1983.

"Low Temperature Automotive Emissions (METFAC, Report 2)," Sierra Research Report No. SR83-11-01, prepared for Alaska Department of Environmental Conservation, November 1983.

"Light-Duty Vehicle CO Emissions During Cold Weather," SAE Technical Paper No. 831698, Society of Automotive Engineers, Fuels and Lubricants Meeting, October 31-November 3, 1983.

"Proposed Emission Cutpoints for the Anchorage Inspection and Maintenance Program," Sierra Research Report No. SR83-06-01, prepared for Municipality of Anchorage, Alaska, June 1983.

“A Study of Air Pollution Offsets for Cogeneration and Resource Recovery Technologies in Kern County – Interim Report: Project Inventory,” Sierra Research Report No. SR82-01-01, prepared for Kern County Air Pollution Control District and Kern County Council of Governments, January 1983.

“Automotive Retrofit Devices for Improving Cold Weather Emissions and Fuel Economy,” Sierra Research Report No. SR82-10-01, prepared for U.S. Army Cold Regions Research and Engineering Laboratory, October 1982.

“Carbon Monoxide Air Quality Trends in Fairbanks, Alaska,” Sierra Research Report No. SR82-09-01, prepared for Fairbanks North Star Borough, September 1982.

“Cogeneration and Resource Recovery in Kern County – Final Report,” Sierra Research Report No. SR82-06-01, prepared for Kern County Air Pollution Control District and Kern County Council of Governments, June 1982.

“Cold Weather CO Problems – An Analysis of Research Needs,” Sierra Research Report No. SR82-04-01, prepared for Alaska Department of Environmental Conservation, April 1982.

“The Potential for the Use of Catalytic NOx Controls on Stationary Sources in California,” Sierra Research Report No. SR82-02-01, February 1982.

“Staff Report - Cogeneration Technology and Resource Recovery Status Report,” California Air Resources Board, November 1981.

“The Effect of Clean Air Act Amendments on High Altitude Passenger Cars,” Sierra Research Report No. SR81-09-01, September 1981.

“Staff Report - Public Meeting to Discuss Proposed Guidelines for the Control of Emissions from Coal-Fired Power Plants (81-11-2),” California Air Resources Board, June 1981.

“Staff Report - Public Hearing to Consider Amendments to Title 13, Section 1960.1, CAC, Regarding Exhaust Emission Standards and Test Procedures for 1983 and Subsequent Model Passenger Cars, Light-Duty Trucks and Medium-Duty Vehicles,” California Air Resources Board, May 1981.

“Staff Report - Suggested Control Measure for the Control of Hydrogen Sulfide Emissions from Geothermal Operations at the Geysers Known Geothermal Resources Area (81-6-1),” California Air Resources Board, April 1981.

“Staff Report - Proposed Methodology for Calculating a NOx Amelioration Factor for Light-Duty Diesel Vehicles,” California Air Resources Board, April 1981.

"Staff Report - A Proposed Air Resources Board Policy Regarding Incineration as an Acceptable Technology for PCB Disposal," California Air Resources Board, March 1981.

"Staff Report - Public Meeting to Discuss a Proposed Air Resources Board Policy Regarding Incineration as an Acceptable Technology for PCB Disposal," California Air Resources Board, March 1981.

"Staff Report - Suggested Control Measure for the Control of Oxides of Nitrogen Emissions from Electric Utility Gas Turbines (81-4-2)," California Air Resources Board, March 1981.

"Staff Report - Public Hearing to Consider Amendments to Title 13, Section 1956.7, CAC, Regarding Exhaust Emission Standards and Test Procedures for 1984 and Subsequent Model Heavy Duty Engines (81-1-1)," California Air Resources Board, January 1981.

"Gasohol: Technical, Economic or Political Panacea?" SAE Paper No. 800891, 1980.

"Staff Reports Related to Public Hearing to Consider Amendments to Rule 475.1 of the South Coast Air Quality Management District and to Rule 59.1 of the Ventura County Air Pollution Control District, Which Control the Emissions of Oxides of Nitrogen from Power Plants," California Air Resources Board, January 1980; March 1980; November 1980; December 1980.

"Staff Report - Public Hearing to Consider Confirmation of Emergency Adoption of Section 1960.4, Title 13, CAC, Regarding Special NOx Standards for Small-Volume Manufacturers (80-25-1)," California Air Resources Board, December 1980.

"Staff Report - Public Hearing to Consider Adoption of California Assembly- Line Test Procedures for Certain 1982 Model Year Vehicles and Adoption of Section 2060, Title 13, CAC, Incorporating the Test Procedures (80-26-4)," California Air Resources Board, December 1980.

"Staff Report - Public Hearing to Consider Repeal of 1955-1965 Model Year Motor Vehicle Exhaust Retrofit Emission Control Requirements - Title 13, CAC Section 2007 (80-20-2)," California Air Resources Board, October 1980.

"Staff Report - Public Hearing to Consider Amendments to Rule 424 of the Kern County APCD Controlling Emissions of Sulfur Oxide from Steam Generators Used in Oil Field Operations," California Air Resources Board, October 1980.

"Staff Report - Proposed Amendments to Title 13, CAC, Sections 2035-42, Regarding Warranty of Emissions-Related Components of Vehicles (80-18-1)," California Air Resources Board, September 1980.

"Staff Report - Proposed Amendment to Title 13, CAC Regarding Standards and Test Procedures for Modified Vehicles - 1981 and Subsequent Passenger Cars, Light-Duty Trucks and Medium-Duty Vehicles," California Air Resources Board, September 1980.

"Staff Report - Public Meeting to Discuss Issues Related to Power Plant Siting," California Air Resources Board, September 1980.

"Staff Report - Emergency Public Hearing to Consider Amendments to Title 13, CAC, Regarding Exhaust Emission Standards for Oxides of Nitrogen (NOx) from Vehicles Produced by Small Manufacturers for the 1982-1986 Model Years of Passenger Cars, Light-Duty Trucks and Medium- Duty Vehicles," California Air Resources Board, August 1980.

"Staff Report - Emergency Public Hearing to Consider Adoption of a Particulate Exhaust Emission Standard for 1982 and Subsequent Model Year Light-Duty Diesel Vehicles and to Consider Amending the 1982 NOx Exhaust Emission Standard for Those Vehicles (80-15-2)," California Air Resources Board," August 1980.

"Cogeneration Technology and Resource Recovery Status Report," California Air Resources Board, August 1980.

"Staff Report - Response to the Motorcycle Manufacturers' Petition Requesting the Board Reevaluate the 1.0 Gram Per Kilometer Exhaust Emission Standard for 1982 and Subsequent Model Year Motorcycles (80-13-3)," California Air Resources Board, July 1980.

"Staff Report - Inventory of Potential Cogeneration Technology and Resource Recovery Projects Planned or Proposed to Be Constructed Before 1987," California Air Resources Board, July 1980.

"Staff Report - Public Hearing to Consider Proposed Amendments to Kern County APCD Rule 424 - Sulfur Compounds from Oil Field Steam Generators," California Air Resources Board, May 1980.

"Staff Report - Public Hearing to Consider Amending the Rules and Regulations of Imperial County Air Pollution Control District, Los Angeles County Air Pollution Control District and San Bernardino County Air Pollution Control District," California Air Resources Board, May 1980.

"Staff Report - Public Hearing to Consider Amendments to Title 13, CAC, Regarding the Extension of California's 1980 Heavy-Duty Engine Emission Standards through the 1983 Model Year," California Air Resources Board, May 1980.

"Staff Report - Public Hearing to Consider Amendments to the Rules and Regulations of the Kern County APCD Amendments to Rule 210.1, Standard for Authority to Construct, and Addition of Rule 425, Relating to Retrofit Control for Emissions of Oxides of

Nitrogen from Oil Fired Steam Generators," California Air Resources Board, March 1980.

"Staff Report - Public Hearing to Consider Proposed Amendments to Title 13 of the Administrative Code and to the Exhaust and Evaporative Emission Standards and Test Procedures for 1981 and Subsequent Model year Passenger Cars, Light-Duty Trucks and Medium-Duty Vehicles," California Air Resources Board, March 1980.

"Air Pollution Aspects of Resource Recovery Facilities," California Air Resources Board, March 1980.

"Memorandum of Agreement - Hondo 'A' Development Santa Ynez Unit, Santa Barbara Channel between The State of California, County of Santa Barbara and Santa Barbara Air Pollution Control District and Exxon Company, U.S.A.," California Air Resources Board, February 1980.

"A Report on California's Certificate of Compliance Program prepared for the California Legislature Joint Legislative Budget Committee in accordance with the requirements of the Supplemental Report on Item 194 of the Committee of Conference on the Budget," California Air Resources Board, December 1979.

"Status Report on the Need for/and Feasibility of a 0.4 NOx Standard for Light Duty Motor Vehicles," California Air Resources Board, December 1979.

"Staff Report - Status of NOx Control for Steam Generators and Availability of NOx Trade-offs in Kern County (79-27-1b)," California Air Resources Board, November 1979.

"Staff Report - Public Meeting to Consider Model Rule for the Control of Oxides of Nitrogen Emissions from Stationary Internal Combustion Engines (79-28-2)," California Air Resources Board, November 1979.

"First Annual Report to the Legislature on the Mandatory Vehicle Inspection Program (MVIP)," California Air Resources Board, October 1979.

"Chapter 27, California Lead Control Strategy - Revision to the State of California Implementation Plan for the Attainment and Maintenance of Ambient Air Quality Standards," California Air Resources Board, September 1979.

"Staff Report - Public Hearing to Reconsider the Adoption by the Board into the Regulations of the Kern County Air Pollution Control District on March 23, 1979, of Rule 424, for the Control for Emissions of Sulfur Compounds from Steam Generators Used in Oil Field Operations," California Air Resources Board, August - September 1979.

"Staff Report - Public Hearing to Consider the Adoption of Chapter 27 as a Revision to the State of California Implementation Plan for the Attainment and Maintenance of the National Ambient Air Quality Standards for Lead," California Air Resources Board, August 1979.

"Staff Report - Public Hearing to Consider Amendment of the State Regulation Which Limits the Lead Content of Gasoline Sold in California (79-22-1)," California Air Resources Board, August 1979.

"Staff Report – Alcohols and Alcohol/Gasoline Blends as Motor Fuels," California Air Resources Board, August 1979.

"Centralized Vehicle Inspection/Maintenance in California," California Air Resources Board, May 1979.

"Staff Report - Public Hearing to Consider Changes to the Air Resources Board's Standards and Test Procedures for 1980 and Subsequent Model Passenger Cars, Light-Duty Trucks, and Medium-Duty Vehicles," California Air Resources Board, April 1979.

"Staff Report - Public Hearing to Consider Proposed Changes in the Regulations of the Air Resources Board Regarding Predelivery Inspection and Compliance Test Evaluation," California Air Resources Board, April 1979.

"An Evaluation of California's Private Garage Emissions Inspection Program," California Air Resources Board, March 1979.

"Staff Report - Proposed Rule For Control of Emissions of Sulfur Compounds From Steam Generators and Boilers Used in Oilfield Operations in the Kern County Air Pollution Control District," California Air Resources Board, March 1979.

"Staff Report - Public Hearing to Consider Adoption of a Regulation Controlling Emissions of Sulfur Compounds from Steam Generators Used in Oilfield Operations in the Kern County APCD," California Air Resources Board, March 1979.

"Staff Report - Revisions to the State of California Implementation Plan (SIP) for the Attainment and Maintenance of National Ambient Air Quality Standards - Kings County, Madera County, Merced County, and Tulare County Non-attainment Plans (NAPs)," California Air Resources Board, February 1979.

"Staff Report - Public Meeting to Consider a Proposed Model New Source Review Rule," California Air Resources Board, January 1979.

"Staff Report - Proposed ARB-CEC Joint Policy Statement of Compliance with Air Quality Laws by New Power Plants (79-1-3)," California Air Resources Board, January 1979.

"Staff Report - Public Hearing to Consider Exhaust Standards for the Mandatory Vehicle Inspection Program," California Air Resources Board, September 1978.

"Staff Report - Public Hearing to Consider Proposed Emissions Warranty Regulations (78-3-1)," California Air Resources Board, February 1978.

"Staff Report - Public Hearing to Consider Proposed Highway Cycle Emission Standard for Passenger Cars, Light Duty Trucks, and Medium- Duty Vehicles (78-1-2)," California Air Resources Board, January 1978.

"Staff Report - Public Hearing to Consider Proposed Changes to Motor Vehicle Emission Standards Test Procedures, and Enforcement Programs (77-20-2)," California Air Resources Board, September 1977.

"Staff Report - Surveillance Bibliography of Passenger Cars, Motorcycles, Heavy-Duty and Medium-Duty Vehicles," California Air Resources Board, July 1977.

"Staff Report - Public Hearing on Proposed Changes to Regulations Regarding California Exhaust Emission Standards and Test Procedures for 1980 and Subsequent Model Motor Vehicles (78-9-2)," California Air Resources Board, May 1977.

"Staff Report - Public Hearing on Proposed Changes to Regulations Regarding Allowable Maintenance During New Vehicle Certification of Light-Duty and Medium-Duty Vehicles (77-12-1)," California Air Resources Board, May 1977.

"Staff Report - Public Hearing on Proposed Changes to Regulations Regarding Allowable Maintenance During New Vehicle Certification of Light-Duty and Medium-Duty Vehicles (77-9-2)," California Air Resources Board, April 1977.

"Staff Report - Manganese Fuel Additive MMT (77-9-3)," California Air Resources Board, April 1977.

"Staff Report - Public Hearing to Consider Amendments to the Hydrocarbon Standards and Test Procedures Applicable to 1978 Through 1981 Production Year Motorcycles (77-6-2)," California Air Resources Board, March 1977.

"Staff Report - Status Report on the Mandatory Vehicle Inspection Program (MVIP) (77-4-2)," California Air Resources Board, February 1977.

"Staff Report - Control of Motorcycle Evaporative Emissions and Certification of Motorcycle Fuel Fill Pipes (77-63)," California Air Resources Board, March 1977.

"Staff Report - Public Hearing on Proposed Changes to Regulations Regarding Vehicle Evaporative Emission Standards for 1980 and Subsequent Model Motor Vehicles (76-22-2 c)," California Air Resources Board, November 1976.

"Staff Report - Public Hearing on Proposed Changes to Regulations Regarding Exhaust Emission Standards and Test Procedures for 1979 and Subsequent Model Passenger Cars, Light-Duty Trucks and Medium-Duty Vehicles (76-22-2 a)," California Air Resources Board, November 1976.

"Staff Report - Public Hearing on Proposed Changes to Regulations Regarding Allowable Maintenance During New Vehicle Certification of Light-Duty and Medium-Duty vehicles (76-22-2 b)," California Air Resources Board, November 1976.

"Staff Report - Evaluation of Mandatory Vehicle Inspection and Maintenance Programs," California Air Resources Board, May-August 1976.

"Staff Report - Public Hearing to Consider Proposed Changes to Regulations Regarding Approval of 1978 and Subsequent Model Light-Duty Trucks and Heavy-Duty Engines (76-6-2)," California Air Resources Board, March 1976.

"Staff Report - Public Hearing to Consider Amendments to California Fuel Evaporative Emissions Test Procedures for 1978 and Subsequent Model Gasoline-Powered Vehicles (76-6-3)," California Air Resources Board, March 1976.

"Staff Report - Public Hearing Regarding Amendment of Emission Standards and Test Procedures for Motorcycles (76-1-4)," California Air Resources Board, January 1976.

"Staff Report - Catalyst Service and Replacement Regulations (75-20-2)," California Air Resources Board, October 1975.

"Staff Report - Emergency Action to Amend the New Vehicle Approval Regulations Regarding Catalyst Change (75-18-2)," California Air Resources Board, September 1975.

"Staff Report - Progress Report on Technology to Control Sulfate Emissions from Catalyst-Equipped Vehicles (75-15-2)," California Air Resources Board, August 1975.

"Staff Report - Public Hearing to Consider 1978 Production Motorcycle Emission Standards (75-14-2)," California Air Resources Board, July 1975.

"Staff Report - Consideration of Regulation Change to Extend the Alternate Heavy-Duty Engine Standards for 1977 and Subsequent Years (75-14-3)," California Air Resources Board, July 1975.

"Staff Report - Motorcycle Emission Control Strategies (75-11-4)," California Air Resources Board, June 1975.

"Staff Report - Catalytic Converter Retrofit Program - Used Vehicles Retrofitted with Universal Oil Products Catalytic Converters Final Report," California Air Resources Board, May 1975.

"Staff Report - Estimate of Contribution of Motorcycles to California Air Pollution (75-9-5)," California Air Resources Board, May 1975.

"Staff Report - Public Hearing for Adoption of Proposed Changes to Vehicular Enforcement Regulations Including Recall Procedures (75-9-4)," California Air Resources Board, May 1975.

"Staff Report - Public Hearing to Consider Inspection Specification Regulations in Title 13 -- New Vehicles (continued) (75-9-3a)," California Air Resources Board, May 1975.

"Staff Report - Emergency Action to Delete High Altitude Test Provisions from the 1975 and Subsequent New Vehicle Approval Procedures (75-7-7)," California Air Resources Board, April 1975.

"Staff Report - Public Hearing to Consider Fuel Evaporative Emission Regulations for Light-Duty Vehicles (75-7-6)," California Air Resources Board, April 1975.

"Staff Report - Reconsideration of Exhaust Emission Standards for 1977 and Subsequent Model-Year Heavy-Duty Engines (75-7-2)," California Air Resources Board, April 1975.

"Staff Report - Exhaust Emission Standards for 1977 Model-Year Light-Duty Vehicles (75-5-2)," California Air Resources Board, March 1975.

"Smog: A Report to the People," Caltech Environmental Quality Lab, 1972.

13. Gary Rubenstein (Alternative Sites – Environmental Justice)

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State of California

Energy Resources

Conservation and Development Commission

In the Matter of: Application for Certification for the PUENTE POWER PROJECT	Docket No. 15-AFC-01 EXPERT DECLARATION OF GARY RUBENSTEIN REGARDING ALTERNATIVE SITES - ENVIRONMENTAL JUSTICE

I, Gary Rubenstein, declare as follows:

1. I am employed by Sierra Research, which has been retained by the Applicant to conduct certain analyses associated with the proposed Puente Power Project (Project) and am duly authorized to make this declaration.

2. I earned a Bachelor of Science Degree in Engineering from the California Institute of Technology in 1973. I have over 44 years of experience regarding the evaluation of air quality and public health impacts, including impacts associated with greenhouse gas emissions, and related issues in the disciplines of alternatives, biological resources (nitrogen deposition), traffic and transportation (thermal plumes), visual resources (visible plumes), energy efficiency, and environmental justice. A copy of my current curriculum vitae is attached to this declaration as Attachment A. Based on my education, training and experience, I am qualified to provide expert testimony as to the matters addressed herein.

3. Except where stated on information and belief, the facts set forth herein are true of my own personal knowledge, and the opinions set forth herein are true and correct articulations of my opinions. If called as a witness, I could and would testify competently to the

facts and opinions set forth herein and in the other Applicant's Exhibits identified herein.

4. I have reviewed and am knowledgeable of the contents of the California Energy Commission (CEC) Staff Final Staff Assessment (FSA), Part 1, Section 4.2, Alternatives (portions pertaining to environmental justice) (CEC TN #214712). I have also reviewed and am knowledgeable of the contents of the statements of Intervenors related to Environmental Justice issues as related to project alternatives.[1]

5. Environmental Justice concerns arise when a proposed project (1) results in a significant environmental impact, AND (2) that significant impact falls disproportionately on disadvantaged communities.[2] However, the in-depth technical analyses prepared by both Staff and Applicant demonstrate that the Project will not result in any significant environmental impacts, either alone or on a cumulative basis. Because the Project does not result in any significant environmental impacts, no Environmental Justice issues arise.

6. In the Applicant's Environmental Justice analysis, the percentages of minority and low-income populations were assessed for each census tract that falls entirely or partly within the environmental justice project area (study area for environmental-justice analysis), which is bounded by the 6-mile radius around the proposed Project site. The 2013 American Community Survey (ACS) data produced and released by the U.S. Census Bureau were used to characterize affected populations in terms of poverty status and ethnic/racial composition. To place these data in a broader and more appropriate geographic context, they were compared to similar data collected for the affected county—in this case, Ventura County—and California. Impacts were then assessed by determining whether disproportionate impacts

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[1] Statement of Irene Valencia on behalf of the California Environmental Justice Alliance (CEC TN #215444); Statement of Raul Lopez on behalf of the California Environmental Justice Alliance (CEC TN #215445); Statement of David Pellow (CEC TN #215448); Statement of Grace Chang on behalf of FFIERCE (CEC TN #251449).

[2] 59 FR 32, February 16, 1994. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations. Section 1-101 (Agency Responsibilities): "identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low-income populations…"

associated with the proposed project would occur in an area occupied by low-income or minority populations as defined above.[3]

7. The Applicant's EJ analysis determined that the majority of the study area comprises minority populations,[4] and therefore the minority population in the study area for environmental justice is "meaningfully greater" than the project region as a whole. The Applicant also applied the U.S. Department of Health and Human Services definition of "low income" and determined that no census tracts in the study area for environmental justice have low-income populations that exceed the 50 percent threshold for environmental-justice analysis, so the low-income populations in the surrounding area are not considered meaningfully greater than in the project region as a whole.[5]

8. In the FSA, the CEC staff used the decennial census (2010) and the ACS data and concluded that the population in the census blocks within the 6-mile radius around the project site represent an EJ population based on race and ethnicity—the same conclusion as that reached by the Applicant. However, in contrast to Applicant's analysis, Staff determined that the below-poverty-level population in the cities of Oxnard and Port Hueneme also constitutes an EJ population based on poverty.[6] Staff determined that the closest residences to the Project site within a disadvantaged census tract are approximately 4.5 miles away.[7]

9. The Applicant's analysis of disadvantaged communities surrounding the Project site did not use the CalEnviroScreen tool because the CES screening factors do not follow the current established methodology (and EO 12898) for environmental justice community identification. Although CES does include a range of socioeconomic and population characteristics in its calculations, CES 2.0, which was the version of the screening tool that was

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[3] AFC Section 4.10.2.7 (Applicant's Exhibit No. 1016; CEC TN #204219-17).

[4] Supplemental EJ testimony (Applicant's Exhibit No. 1069; CEC TN #207111, p. 2).

[5] AFC Section 4.10.2.7.2 (Applicant's Exhibit No. 1016; CEC TN #204219-17).

[6] FSA, pp. 4.5-3—4.5-4 (CEC TN #214712).

[7] FSA, p. 4.5-11 (CEC TN #214712).

available at the time the analysis was prepared, did not consider race/ethnicity in the calculation of a vulnerability score. EO 12898 and CEQ guidance are very specific that race, ethnicity, and poverty rates should be used to identify environmental justice populations. Therefore, use of the CES tool for purposes of conducting an environmental justice analysis does not comport with underlying legal and policy requirements.[8] However, the data in the CES tool can be used to obtain information regarding race, ethnicity and poverty even if the CES scores are not used directly.

10. The Staff's analysis reviewed CES 2.0 data for the disadvantaged communities within a six-mile radius of the Project site "to better understand the characteristics of the areas where the impact would occur and ensure that disadvantaged communities in the vicinity of the proposed project have not been missed when screened by race/ethnicity and poverty."[9] The Staff concluded that of the five disadvantaged community census tracts within a six-mile radius of the Project site, two have percentiles above 90 for population characteristics and three have individual indicators in both the pollution burden and population characteristics groups of indicators with percentiles above 90.[10]

11. The Applicant assessed the proximity of Alternative Site 8 identified in FSA Section 4.2 (Ormond Beach Area Off-Site Alternative) to socioeconomically disadvantaged communities and determined that the site is adjacent to census tracts with the highest density of minority populations in the City of Oxnard. The minority population densities in census tracts adjacent to the Ormond Beach Area Off-Site Alternative are much greater than those adjacent to the proposed Project Site.

12. In the FSA, Staff performed a demographic screening analysis for the Ormond Beach Area Off-Site Alternative similar to that performed for the proposed Project site

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[8] Supplemental EJ testimony (Applicant's Exhibit No. 1069; CEC TN #207111, p. 1).
[9] FSA, p. 4.5-7 (CEC TN #214712).
[10] FSA, p. 4.5-11 and Environmental Justice Table 4 (CEC TN #214712).

and concluded that the population residing in the area of the Ormond Beach Area Off-Site Alternative constitutes an EJ population based on race and ethnicity.[11] Staff also used CES 2.0 to evaluate the characteristics of communities in the area of the alternative project site and concluded that the Ormond Beach Area Off-Site Alternative is located within a six-mile radius of six disadvantaged community census tracts, while the proposed Project site is at least 3 miles further from all of these disadvantaged communities.[12]

13. Finally, Staff noted that the Ormond Beach Area Off-Site Alternative is located within a census tract (6111004715) that is burdened by public health related indicators, and that the nearest sensitive receptor "could be very near the project (at the facility fenceline) if it were located at this site."[13]

14. The figure below compares the proximity of disadvantaged communities identified by Staff using CES 2.0 to the Project Area[14] and to the Ormond Beach Area Off-Site Alternative.[15] The figure shows that the census tracts near the Ormond Beach Area Off-Site Alternative are home to a higher number of minority populations than the proposed Project Area, and that there are far more disadvantaged communities[16] in the vicinity of Ormond Beach Area Off-Site Alternative than in the Project Area. These differences are quantified in the following tables, which show the percent of the areas within 1, 3 and 6 miles of each of the two locations that contain 50% or more minority population and that are defined as disadvantaged communities in CES.

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[11] FSA p. 4.2-79 (CEC TN #214712).

[12] FSA p. 4.2-82 (CEC TN #214712).

[13] FSA p. 4.2-88 (CEC TN #214712).

[14] FSA Section 4.5, Environmental Justice – Figure 1, following p. 4.5-20 (CEC TN #214712).

[15] FSA Section 4.2, Alternatives – Figure 8, following p. 4.2-163 CEC TN #214712).

[16] CES defines disadvantaged communities as census tracts with scores between 75 and 100 percent.

Location	Percent of Surrounding Area within a Minority Population Community (Minority Population ≥ 50%)		
	Within 1 mile	Within 3 miles	Within 6 miles
P3 Project Site (from Environmental Justice Figure 1)	0%	15%	18%
Ormond Beach Area Off-Site Alternative (from Alternatives Figure 8)	15%	39%	25%

Location	Percent of Surrounding Area within a Disadvantaged Community (CES Score ≥ 75%)		
	Within 1 mile	Within 3 miles	Within 6 miles
P3 Project Site (from Environmental Justice Figure 1)	0%	0%	3%
Ormond Beach Area Off-Site Alternative (from Alternatives Figure 8)	86%	37%	20%

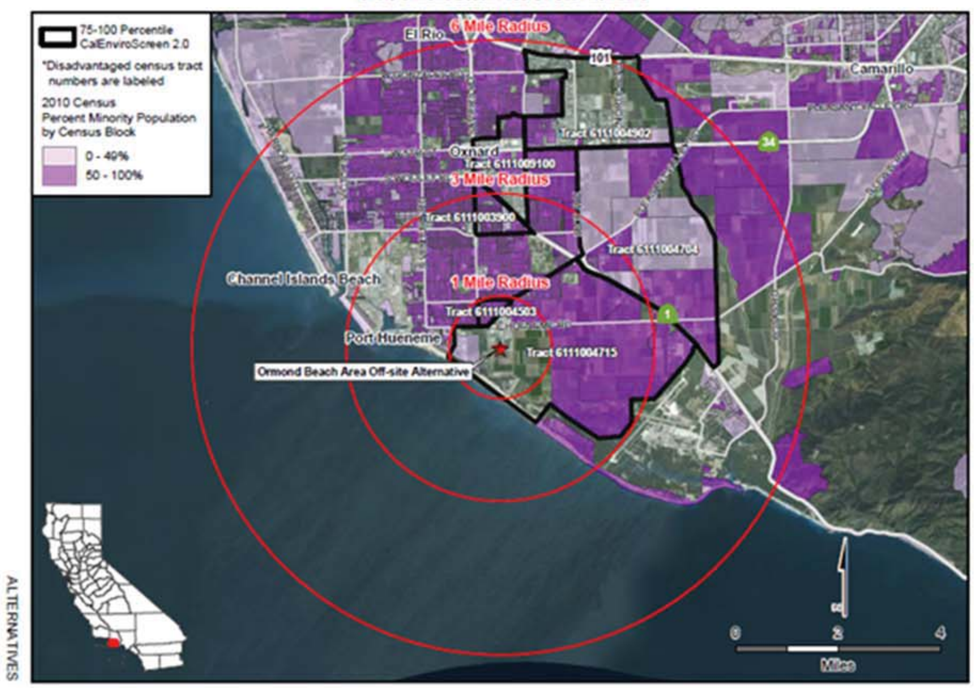
The data in these tables clearly show that there are more minority and disadvantaged communities in the area surrounding Ormond Beach Area Off-Site Alternative than in the Project Area.

15. I hereby sponsor this declaration into evidence in these proceedings as Applicant's Exhibit No. 1137.

ENVIRONMENTAL JUSTICE - FIGURE 1
Puente Power Project (P3) - Census 2010 Minority Population by Census Block with CalEnviroScreen Disadvantaged Communities by CensusTracts

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION
SOURCES: Census 2010 PL 94-171 Data and CalEnviroScreen 2.0 CalEPA 2014

ALTERNATIVES - FIGURE 8
Puente Power Project - Census 2010 Minority Population by Census Block with CalEnviroScreen Disadvantaged Communities by Census Tracts for the Ormond Beach Area Off-site Alternative



CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION
SOURCES: Census 2010 PL 94-171 Data and CalEnviroScreen 2.0 CalEPA 2014

Executed on January 24, 2017, at Sacramento, California.

I declare under penalty of perjury of the laws of the State of California that the foregoing is true and correct.

Gary Rubenstein

ATTACHMENT A

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research

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Résumé

Gary S. Rubenstein

Education

1973, B.S., Engineering, California Institute of Technology

Professional Experience

8/81 to present Senior Partner
Sierra Research

As one of the founding partners of Sierra Research, responsibilities include project management and technical and strategy analysis in all aspects of air quality planning and strategy development; project licensing and impact analysis; emission control system design and evaluation; rulemaking development and analysis; vehicle inspection and maintenance program design and analysis; and automotive emission control design, from the initial design of control systems to the development of methods to assess their performance in customer service. As the Partner principally responsible for Sierra Research's activities related to stationary sources, he has supervised the preparation of control technology assessments, environmental impact reports and permit applications for numerous industrial and other development projects.

While with Sierra, Mr. Rubenstein has managed and worked on numerous projects, including preparation of nonattainment plans; preparation and review of emission inventories and control strategies; preparation of the air quality portions of environmental review documents for controversial transportation, energy, mineral industry and landfill projects; preparation of screening health risk assessments and supporting analyses; and the development of air quality mitigation programs. Mr. Rubenstein has managed the preparation of air quality licensing applications for over 18,000 megawatts of generating capacity before the California Energy Commission, and has managed air quality analyses for over 30,000 megawatts of generating capacity in a variety of jurisdictions.

Mr. Rubenstein and his colleagues at Sierra have followed literature related to climate change and the control of greenhouse gas emissions since the early 1990s. The firm's work has focused on understanding the scientific, legal and regulatory basis for the regulation of greenhouse emissions by various jurisdictions in the United States, and on the evaluation of the costs and environmental impacts of alternative regulatory approaches for controlling greenhouse gas emissions.

Mr. Rubenstein has presented testimony and served as a technical expert witness before numerous state and local regulatory agencies, including the U.S. Environmental Protection Agency, California State Legislative Committees, the California Air Resources Board, the California Energy Commission, the California Public Utilities Commission, numerous California air pollution control districts, the Connecticut Department of Environmental Protection, the Hawaii Department of Health, and the Alabama Department of Environmental Management. Mr. Rubenstein has also served as a technical expert on behalf of the California Attorney General and Alaska Department of Law, and has provided expert witness testimony in a variety of administrative and judicial proceedings.

6/79 to 7/81 Deputy Executive Officer
California Air Resources Board

Responsibilities included policy management and oversight of the technical work of ARB divisions employing over 200 professional engineers and specialists; final review of technical reports and correspondence prepared by all ARB divisions prior to publication, covering such diverse areas as motor vehicle emission standards and test procedures, motor vehicle inspection and maintenance, and air pollution control techniques for sources such as oil refineries, power plants, gasoline service stations and dry cleaners; review of program budget and planning efforts of all technical divisions at ARB; policy-level negotiations with officials from other government agencies and private industry regarding technical, legal, and legislative issues before the Board; representing the California Air Resources Board in public meetings and hearings before the California State Legislature, the California Energy Commission, the California Public Utilities Commission, the Environmental Protection Agency, numerous local government agencies, and the news media on a broad range of technical and policy issues; and assisting in the supervision of over 500 full-time employees through the use of standard principles of personnel management and motivation, organization, and problem solving.

7/78 – 7/79 Chief, Energy Project Evaluation Branch
Stationary Source Control Division
California Air Resources Board

Responsibilities included supervision of ten professional engineers and specialists, including the use of personnel management and motivation techniques; preparation of a major overhaul of ARB's industrial source siting policy; conduct of negotiations with local officials and project proponents on requirements and conditions for siting such diverse projects as offshore oil production platforms, coal-fired power plants, marine terminal facilities, and almond-hull burning boilers.

During this period, Mr. Rubenstein was responsible for the successful negotiation of California's first air pollution permit agreements governing a liquefied natural gas terminal, coal-fired power plant, and several offshore oil production facilities.

10/73 to 7/78 Staff Engineer
Vehicle Emissions Control Division
California Air Resources Board

Responsibilities included design and execution of test programs to evaluate the deterioration of emissions on new and low-mileage vehicles; detailed analysis of the effect of California emission standards on model availability and fuel economy; analysis of proposed federal emission control regulations and California legislation; evaluation of the cost-effectiveness of vehicle emission control strategies; evaluation of vehicle inspection and maintenance programs, and preparation of associated legislation, regulations and budgets; and preparation of detailed legal and technical regulations regarding all aspects of motor vehicle pollution control. Further duties included preparation and presentation of testimony before the California Legislature and the U.S. Environmental Protection Agency; preparation of division and project budgets; and creation and supervision of the Special Projects Section, a small group of highly trained and motivated individuals responsible for policy proposals and support in both technical and administrative areas (May 1976 to July 1978).

Credentials and Memberships

Air & Waste Management Association (Past Chair, Board of Directors, Golden West Section; Past Chair, Board of Directors, Mother Lode Chapter)

American Society of Mechanical Engineers

Qualified Environmental Professional, Institute of Professional Environmental Practice, 1994

Selected Publications (Author or Co-Author)

"Multipollutant Approaches to Regulation," presentation at the California Council for Environmental and Economic Balance 2016 Summer Issues Seminar, July 11, 2016.

"Air Quality and Public Health," presentation at the California Council for Environmental and Economic Balance 2016 Summer Issues Seminar, July 13, 2016.

"Overview of the California Environmental Quality Act," presentation for private client, June 2016.

"The Efficacy of Greenhouse Gas Emission Caps at Local Refineries," presentation to the Bay Area Air Quality Management District Advisory Council, April 25, 2016.

"Fundaments of Air Quality Planning and Regulation," presentation to the Jiangsu Environmental Protection Department, October 20, 2015.

"Carbon Pollution Standards for New, Modified and Reconstructed Power Plants – Final Rule and Impacts," presentation for private clients, August 27, 2015.

"Understanding the Supreme Court's MATS Ruling," presentation for private clients, July 15, 2015.

"OEHHA's New Hot Spots Exposure and Assessment Guidelines," prepared for private client, October 30, 2014.

"Diesel Particulate Matter Regulation and Health Impacts," presentation at the 2012 Railroad Environmental Conference on October 16, 2012, in Champagne-Urbana, Illinois.

"Using Screening Tools to Identify Priority Communities," presentation at the California Council for Environmental and Economic Balance 2012 Summer Issues Seminar on July 16, 2012, at Squaw Valley, California.

"Slogging Through the Modeling Maze: New National Ambient Air Quality Standards for NO_2, SO_2 and $PM_{2.5}$," presentation to the Air & Waste Management Association on February 12, 2012, in Sacramento, California.

"Climate Change Regulation and Environmental Justice," presentation at the California Council for Environmental and Economic Balance 2011 Summer Issues Seminar on July 11, 2011, at Squaw Valley, California.

"EPA Greenhouse Gas Tailoring Rule," presentation to the Air & Waste Management Association on February 16, 2011, at Bakersfield, California.

"Non-Traditional ERCs – Giving Credit Where Credit is Due," presentation to the California Desert Air Working Group on November 17, 2010, at Laughlin, Nevada.

"Sensitivity and Vulnerability: Community Health Factors as Part of Environmental Decision Making," presentation at the California Council for Environmental and Economic Balance 2010 Summer Issues Seminar on July 19, 2010, at Squaw Valley, California.

"Evaluation of CTM-039 Dilution Method for Measuring PM_{10}/$PM_{2.5}$ Emissions from Gas-Fired Combustion Turbines," August 20, 2009.

"Application of SCR to Small Sources: A Case Study" presentation to the Air & Waste Management Association on January 29, 2009, in Diamond Bar, California.

"Dealing with the Scarcity of PM Offsets," presentation to Law Seminars International: Air Quality Regulation in California on April 15, 2008, in Los Angeles, CA.

"Field Demonstration of a Dilution-Based Particulate Measurement System," presentation to Stationary Source Sampling and Analysis for Air Pollutants on March 5, 2008, in San Diego, CA.

"The California Global Warming Solutions Act of 2006 – Implementation Considerations," presentation to Law Seminars International: Energy in California 2007 on September 17, 2007, in San Francisco, CA.

"Preparing for and Conducting Air Quality Compliance Audits," presentation to California Desert Air Working Group on October 19, 2006, in Big Bear Lake, CA.

"Test Results from Sugar Cane Bagasse and High Fiber Cane Co-fired with Fossil Fuels," Biomass and Bioenergy, Vol. 30, Issue 6. pp. 565-574. June 2006.

"Gas Turbine Particulate Matter Emissions – Update," Presentation to ASME/EIGTI Turbo Exp. on June 9, 2005 in Reno, NV.

"Gas Turbine Startup Emissions," Presentation to ASME/IGTI Turbo Expo on June 9, 2005 in Reno, NV.

"Gas Turbine Particulate Matter Emissions – Update," Presentation to ASME/IGTI Turbo Expo on June 18, 2003 in Atlanta, GA.

"Sources of Uncertainty When Measuring Particulate Matter Emissions from Natural Gas-Fired Combustion Turbines," presentation to Air & Waste Management Association on March 30, 2001 in San Diego, CA.

"An Analysis of the Effect on Emissions of Allowing Drive-Thru Service Lanes," Sierra Research Report No. SR97-11-01, prepared for California Business Properties Association, November 10, 1997.

"Searles Valley Air Quality Study (SVAQS) Final Report," Sierra Research Report No. SR94-02-01, prepared for North American Chemical Company, February 1994.

"Regulatory Strategies for Reducing Emissions from Marine Vessels in California Waters," Sierra Research Report No. SR91-10-01, prepared for the California Air Resources Board, October 4, 1991.

"An Analysis of the Effect on Emissions of Eliminating Drive-Thru Services Lanes," Sierra Research Report No. SR91-07-03, prepared for California Restaurant Association, July 25, 1991.

“Development of the CALIMFAC California I/M Benefits Model,” Sierra Research Report No. SR-91-01-01, prepared for the California Air Resources Board, Agreement No. A6-173-64, January 1991.

“Criteria Pollutant Emission Inventory for the Coachella Valley Study Area,” Sierra Research Report No. SR90-11-01, prepared for South Coast Air Quality Management District, November 1990.

“User’s Guide to the CALIMFAC California I/M Benefits Model,” Prepared for the California Air Resources Board, May 1990.

“Potential Emissions and Air Quality Effects of Alternative Fuels – Final Report,” Sierra Research Report No. SR89-03-04, prepared for Western States Petroleum Association, March 28, 1989.

“Interprecursor Offset Ratios for Ozone in the Searles Valley,” Sierra Research Report No. SR89-03-02, prepared for Kerr-McGee Chemical Company, March 17, 1989.

“An Assessment of the Quality of California’s Air Pollution Emissions Inventory,” Sierra Research Report No. SR88-05-01, prepared for Western Oil and Gas Association, May 1988.

“Trends in Visibility-Related Emissions Affecting the R-2508 Restricted Airspace,” Sierra Research Report No. SR88-05-02, prepared for Western Oil and Gas Association, May 1988.

“Volume I, Executive Summary: Impacts of Air Quality Regulations on Visibility-Related Emissions in the California R-2508 Restricted Airspace,” Sierra Research Report No. SR88-03-02, prepared for Western Oil and Gas Association, March 1988.

“Volume II, Determination of California Air Basins Which Can Affect Visibility in the R-2508 Restricted Airspace,” Sierra Research Report No. SR88-03-03, prepared for Western Oil and Gas Association, March 1988.

“Air Quality Impact Analysis for the Soledad Biomass Resource Recovery Project,” Sierra Research Report No. SR87-10-01, prepared for Western Forest Power Corp., October 1987.

“Air Quality Impact Analysis for the Honey Lake Biomass Power Plant Project,” Sierra Research Report No. SR87-05-01, prepared for GeoProducts-Zurn/NEPCO, May 22, 1987.

“1986 Update to the Kern County Nonattainment Area Plan,” Sierra Research Report No. SR86-03-01, prepared for Kern County Air Pollution Control District and Kern Council of Governments, March 1986.

"An Analysis of Test Results on Grancor Pollution Control Devices for Automotive Retrofit Programs," Sierra Research Report No. SR85-09-01, prepared for Grancor, September 1985.

"Temperature Correction Factors for California's Motor Vehicle Emissions Model," Sierra Research Report No. SR85-06-01, prepared for the California Air Resources Board, June 1985.

"Critique of the EPA I/M Benefits Model for 1980 and Older Model Cars," Sierra Research Report No. SR85-06-02, prepared for the California Air Resources Board, June 1985.

"Emission Factors for 1980 and Later Model Year California Passenger Cars and Light-Duty Trucks," Sierra Research Report No. SR85-06-03, prepared for the California Air Resources Board, June 1985.

"Technology Assessment for Light-Duty Vehicle Compliance with a 0.4g/m NOx Standard," Sierra Research Report No. SR85-06-04, prepared for the California Air Resources Board, June 1985.

"Development of California's I/M Credits Model," Sierra Research Report No. SR85-06-06, prepared for the California Air Resources Board, June 1985.

"A Comparison of Refueling Emissions Control with Onboard and Stage II Systems," SAE Technical Paper No. 851204, Society of Automotive Engineers, May 1985.

"Evaluation of Automotive CO Emissions Control Techniques at Low Temperatures (METFAC Report 2)," Sierra Research Report No. SR84-11-01, prepared for Alaska Department of Environmental Conservation, November 1984.

"Critical Metal Consumption in Automotive Catalysts – Trends and Alternatives," Sierra Research Report No. SR83-12-01, prepared for Congress of the United States, Office of Technology Assessment, December 1983.

"Low Temperature Automotive Emissions (METFAC, Report 2)," Sierra Research Report No. SR83-11-01, prepared for Alaska Department of Environmental Conservation, November 1983.

"Light-Duty Vehicle CO Emissions During Cold Weather," SAE Technical Paper No. 831698, Society of Automotive Engineers, Fuels and Lubricants Meeting, October 31-November 3, 1983.

"Proposed Emission Cutpoints for the Anchorage Inspection and Maintenance Program," Sierra Research Report No. SR83-06-01, prepared for Municipality of Anchorage, Alaska, June 1983.

"A Study of Air Pollution Offsets for Cogeneration and Resource Recovery Technologies in Kern County – Interim Report: Project Inventory," Sierra Research Report No. SR82-01-01, prepared for Kern County Air Pollution Control District and Kern County Council of Governments, January 1983.

"Automotive Retrofit Devices for Improving Cold Weather Emissions and Fuel Economy," Sierra Research Report No. SR82-10-01, prepared for U.S. Army Cold Regions Research and Engineering Laboratory, October 1982.

"Carbon Monoxide Air Quality Trends in Fairbanks, Alaska," Sierra Research Report No. SR82-09-01, prepared for Fairbanks North Star Borough, September 1982.

"Cogeneration and Resource Recovery in Kern County – Final Report," Sierra Research Report No. SR82-06-01, prepared for Kern County Air Pollution Control District and Kern County Council of Governments, June 1982.

"Cold Weather CO Problems – An Analysis of Research Needs," Sierra Research Report No. SR82-04-01, prepared for Alaska Department of Environmental Conservation, April 1982.

"The Potential for the Use of Catalytic NOx Controls on Stationary Sources in California," Sierra Research Report No. SR82-02-01, February 1982.

"Staff Report - Cogeneration Technology and Resource Recovery Status Report," California Air Resources Board, November 1981.

"The Effect of Clean Air Act Amendments on High Altitude Passenger Cars," Sierra Research Report No. SR81-09-01, September 1981.

"Staff Report - Public Meeting to Discuss Proposed Guidelines for the Control of Emissions from Coal-Fired Power Plants (81-11-2)," California Air Resources Board, June 1981.

"Staff Report - Public Hearing to Consider Amendments to Title 13, Section 1960.1, CAC, Regarding Exhaust Emission Standards and Test Procedures for 1983 and Subsequent Model Passenger Cars, Light-Duty Trucks and Medium-Duty Vehicles," California Air Resources Board, May 1981.

"Staff Report - Suggested Control Measure for the Control of Hydrogen Sulfide Emissions from Geothermal Operations at the Geysers Known Geothermal Resources Area (81-6-1)," California Air Resources Board, April 1981.

"Staff Report - Proposed Methodology for Calculating a NOx Amelioration Factor for Light-Duty Diesel Vehicles," California Air Resources Board, April 1981.

"Staff Report - A Proposed Air Resources Board Policy Regarding Incineration as an Acceptable Technology for PCB Disposal," California Air Resources Board, March 1981.

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"Staff Report - Public Hearing to Consider Amendments to Title 13, Section 1956.7, CAC, Regarding Exhaust Emission Standards and Test Procedures for 1984 and Subsequent Model Heavy Duty Engines (81-1-1)," California Air Resources Board, January 1981.

"Gasohol: Technical, Economic or Political Panacea?" SAE Paper No. 800891, 1980.

"Staff Reports Related to Public Hearing to Consider Amendments to Rule 475.1 of the South Coast Air Quality Management District and to Rule 59.1 of the Ventura County Air Pollution Control District, Which Control the Emissions of Oxides of Nitrogen from Power Plants," California Air Resources Board, January 1980; March 1980; November 1980; December 1980.

"Staff Report - Public Hearing to Consider Confirmation of Emergency Adoption of Section 1960.4, Title 13, CAC, Regarding Special NOx Standards for Small-Volume Manufacturers (80-25-1)," California Air Resources Board, December 1980.

"Staff Report - Public Hearing to Consider Adoption of California Assembly- Line Test Procedures for Certain 1982 Model Year Vehicles and Adoption of Section 2060, Title 13, CAC, Incorporating the Test Procedures (80-26-4)," California Air Resources Board, December 1980.

"Staff Report - Public Hearing to Consider Repeal of 1955-1965 Model Year Motor Vehicle Exhaust Retrofit Emission Control Requirements - Title 13, CAC Section 2007 (80-20-2)," California Air Resources Board, October 1980.

"Staff Report - Public Hearing to Consider Amendments to Rule 424 of the Kern County APCD Controlling Emissions of Sulfur Oxide from Steam Generators Used in Oil Field Operations," California Air Resources Board, October 1980.

"Staff Report - Proposed Amendments to Title 13, CAC, Sections 2035-42, Regarding Warranty of Emissions-Related Components of Vehicles (80-18-1)," California Air Resources Board, September 1980.

"Staff Report - Proposed Amendment to Title 13, CAC Regarding Standards and Test Procedures for Modified Vehicles - 1981 and Subsequent Passenger Cars, Light-Duty Trucks and Medium-Duty Vehicles," California Air Resources Board, September 1980.

"Staff Report - Public Meeting to Discuss Issues Related to Power Plant Siting," California Air Resources Board, September 1980.

"Staff Report - Emergency Public Hearing to Consider Amendments to Title 13, CAC, Regarding Exhaust Emission Standards for Oxides of Nitrogen (NOx) from Vehicles Produced by Small Manufacturers for the 1982-1986 Model Years of Passenger Cars, Light-Duty Trucks and Medium- Duty Vehicles," California Air Resources Board, August 1980.

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"Cogeneration Technology and Resource Recovery Status Report," California Air Resources Board, August 1980.

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"Staff Report - Inventory of Potential Cogeneration Technology and Resource Recovery Projects Planned or Proposed to Be Constructed Before 1987," California Air Resources Board, July 1980.

"Staff Report - Public Hearing to Consider Proposed Amendments to Kern County APCD Rule 424 - Sulfur Compounds from Oil Field Steam Generators," California Air Resources Board, May 1980.

"Staff Report - Public Hearing to Consider Amending the Rules and Regulations of Imperial County Air Pollution Control District, Los Angeles County Air Pollution Control District and San Bernardino County Air Pollution Control District," California Air Resources Board, May 1980.

"Staff Report - Public Hearing to Consider Amendments to Title 13, CAC, Regarding the Extension of California's 1980 Heavy-Duty Engine Emission Standards through the 1983 Model Year," California Air Resources Board, May 1980.

"Staff Report - Public Hearing to Consider Amendments to the Rules and Regulations of the Kern County APCD Amendments to Rule 210.1, Standard for Authority to Construct, and Addition of Rule 425, Relating to Retrofit Control for Emissions of Oxides of

Nitrogen from Oil Fired Steam Generators," California Air Resources Board, March 1980.

"Staff Report - Public Hearing to Consider Proposed Amendments to Title 13 of the Administrative Code and to the Exhaust and Evaporative Emission Standards and Test Procedures for 1981 and Subsequent Model year Passenger Cars, Light-Duty Trucks and Medium-Duty Vehicles," California Air Resources Board, March 1980.

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"Memorandum of Agreement - Hondo 'A' Development Santa Ynez Unit, Santa Barbara Channel between The State of California, County of Santa Barbara and Santa Barbara Air Pollution Control District and Exxon Company, U.S.A.," California Air Resources Board, February 1980.

"A Report on California's Certificate of Compliance Program prepared for the California Legislature Joint Legislative Budget Committee in accordance with the requirements of the Supplemental Report on Item 194 of the Committee of Conference on the Budget," California Air Resources Board, December 1979.

"Status Report on the Need for/and Feasibility of a 0.4 NOx Standard for Light Duty Motor Vehicles," California Air Resources Board, December 1979.

"Staff Report - Status of NOx Control for Steam Generators and Availability of NOx Trade-offs in Kern County (79-27-1b)," California Air Resources Board, November 1979.

"Staff Report - Public Meeting to Consider Model Rule for the Control of Oxides of Nitrogen Emissions from Stationary Internal Combustion Engines (79-28-2)," California Air Resources Board, November 1979.

"First Annual Report to the Legislature on the Mandatory Vehicle Inspection Program (MVIP)," California Air Resources Board, October 1979.

"Chapter 27, California Lead Control Strategy - Revision to the State of California Implementation Plan for the Attainment and Maintenance of Ambient Air Quality Standards," California Air Resources Board, September 1979.

"Staff Report - Public Hearing to Reconsider the Adoption by the Board into the Regulations of the Kern County Air Pollution Control District on March 23, 1979, of Rule 424, for the Control for Emissions of Sulfur Compounds from Steam Generators Used in Oil Field Operations," California Air Resources Board, August - September 1979.

"Staff Report - Public Hearing to Consider the Adoption of Chapter 27 as a Revision to the State of California Implementation Plan for the Attainment and Maintenance of the National Ambient Air Quality Standards for Lead," California Air Resources Board, August 1979.

"Staff Report - Public Hearing to Consider Amendment of the State Regulation Which Limits the Lead Content of Gasoline Sold in California (79-22-1)," California Air Resources Board, August 1979.

"Staff Report – Alcohols and Alcohol/Gasoline Blends as Motor Fuels," California Air Resources Board, August 1979.

"Centralized Vehicle Inspection/Maintenance in California," California Air Resources Board, May 1979.

"Staff Report - Public Hearing to Consider Changes to the Air Resources Board's Standards and Test Procedures for 1980 and Subsequent Model Passenger Cars, Light-Duty Trucks, and Medium-Duty Vehicles," California Air Resources Board, April 1979.

"Staff Report - Public Hearing to Consider Proposed Changes in the Regulations of the Air Resources Board Regarding Predelivery Inspection and Compliance Test Evaluation," California Air Resources Board, April 1979.

"An Evaluation of California's Private Garage Emissions Inspection Program," California Air Resources Board, March 1979.

"Staff Report - Proposed Rule For Control of Emissions of Sulfur Compounds From Steam Generators and Boilers Used in Oilfield Operations in the Kern County Air Pollution Control District," California Air Resources Board, March 1979.

"Staff Report - Public Hearing to Consider Adoption of a Regulation Controlling Emissions of Sulfur Compounds from Steam Generators Used in Oilfield Operations in the Kern County APCD," California Air Resources Board, March 1979.

"Staff Report - Revisions to the State of California Implementation Plan (SIP) for the Attainment and Maintenance of National Ambient Air Quality Standards - Kings County, Madera County, Merced County, and Tulare County Non-attainment Plans (NAPs)," California Air Resources Board, February 1979.

"Staff Report - Public Meeting to Consider a Proposed Model New Source Review Rule," California Air Resources Board, January 1979.

"Staff Report - Proposed ARB-CEC Joint Policy Statement of Compliance with Air Quality Laws by New Power Plants (79-1-3)," California Air Resources Board, January 1979.

"Staff Report - Public Hearing to Consider Exhaust Standards for the Mandatory Vehicle Inspection Program," California Air Resources Board, September 1978.

"Staff Report - Public Hearing to Consider Proposed Emissions Warranty Regulations (78-3-1)," California Air Resources Board, February 1978.

"Staff Report - Public Hearing to Consider Proposed Highway Cycle Emission Standard for Passenger Cars, Light Duty Trucks, and Medium- Duty Vehicles (78-1-2)," California Air Resources Board, January 1978.

"Staff Report - Public Hearing to Consider Proposed Changes to Motor Vehicle Emission Standards Test Procedures, and Enforcement Programs (77-20-2)," California Air Resources Board, September 1977.

"Staff Report - Surveillance Bibliography of Passenger Cars, Motorcycles, Heavy-Duty and Medium-Duty Vehicles," California Air Resources Board, July 1977.

"Staff Report - Public Hearing on Proposed Changes to Regulations Regarding California Exhaust Emission Standards and Test Procedures for 1980 and Subsequent Model Motor Vehicles (78-9-2)," California Air Resources Board, May 1977.

"Staff Report - Public Hearing on Proposed Changes to Regulations Regarding Allowable Maintenance During New Vehicle Certification of Light-Duty and Medium-Duty Vehicles (77-12-1)," California Air Resources Board, May 1977.

"Staff Report - Public Hearing on Proposed Changes to Regulations Regarding Allowable Maintenance During New Vehicle Certification of Light-Duty and Medium-Duty Vehicles (77-9-2)," California Air Resources Board, April 1977.

"Staff Report - Manganese Fuel Additive MMT (77-9-3)," California Air Resources Board, April 1977.

"Staff Report - Public Hearing to Consider Amendments to the Hydrocarbon Standards and Test Procedures Applicable to 1978 Through 1981 Production Year Motorcycles (77-6-2)," California Air Resources Board, March 1977.

"Staff Report - Status Report on the Mandatory Vehicle Inspection Program (MVIP) (77-4-2)," California Air Resources Board, February 1977.

"Staff Report - Control of Motorcycle Evaporative Emissions and Certification of Motorcycle Fuel Fill Pipes (77-63)," California Air Resources Board, March 1977.

"Staff Report - Public Hearing on Proposed Changes to Regulations Regarding Vehicle Evaporative Emission Standards for 1980 and Subsequent Model Motor Vehicles (76-22-2 c)," California Air Resources Board, November 1976.

"Staff Report - Public Hearing on Proposed Changes to Regulations Regarding Exhaust Emission Standards and Test Procedures for 1979 and Subsequent Model Passenger Cars, Light-Duty Trucks and Medium-Duty Vehicles (76-22-2 a)," California Air Resources Board, November 1976.

"Staff Report - Public Hearing on Proposed Changes to Regulations Regarding Allowable Maintenance During New Vehicle Certification of Light-Duty and Medium-Duty vehicles (76-22-2 b)," California Air Resources Board, November 1976.

"Staff Report - Evaluation of Mandatory Vehicle Inspection and Maintenance Programs," California Air Resources Board, May-August 1976.

"Staff Report - Public Hearing to Consider Proposed Changes to Regulations Regarding Approval of 1978 and Subsequent Model Light-Duty Trucks and Heavy-Duty Engines (76-6-2)," California Air Resources Board, March 1976.

"Staff Report - Public Hearing to Consider Amendments to California Fuel Evaporative Emissions Test Procedures for 1978 and Subsequent Model Gasoline-Powered Vehicles (76-6-3)," California Air Resources Board, March 1976.

"Staff Report - Public Hearing Regarding Amendment of Emission Standards and Test Procedures for Motorcycles (76-1-4)," California Air Resources Board, January 1976.

"Staff Report - Catalyst Service and Replacement Regulations (75-20-2)," California Air Resources Board, October 1975.

"Staff Report - Emergency Action to Amend the New Vehicle Approval Regulations Regarding Catalyst Change (75-18-2)," California Air Resources Board, September 1975.

"Staff Report - Progress Report on Technology to Control Sulfate Emissions from Catalyst-Equipped Vehicles (75-15-2)," California Air Resources Board, August 1975.

"Staff Report - Public Hearing to Consider 1978 Production Motorcycle Emission Standards (75-14-2)," California Air Resources Board, July 1975.

"Staff Report - Consideration of Regulation Change to Extend the Alternate Heavy-Duty Engine Standards for 1977 and Subsequent Years (75-14-3)," California Air Resources Board, July 1975.

"Staff Report - Motorcycle Emission Control Strategies (75-11-4)," California Air Resources Board, June 1975.

"Staff Report - Catalytic Converter Retrofit Program - Used Vehicles Retrofitted with Universal Oil Products Catalytic Converters Final Report," California Air Resources Board, May 1975.

"Staff Report - Estimate of Contribution of Motorcycles to California Air Pollution (75-9-5)," California Air Resources Board, May 1975.

"Staff Report - Public Hearing for Adoption of Proposed Changes to Vehicular Enforcement Regulations Including Recall Procedures (75-9-4)," California Air Resources Board, May 1975.

"Staff Report - Public Hearing to Consider Inspection Specification Regulations in Title 13 -- New Vehicles (continued) (75-9-3a)," California Air Resources Board, May 1975.

"Staff Report - Emergency Action to Delete High Altitude Test Provisions from the 1975 and Subsequent New Vehicle Approval Procedures (75-7-7)," California Air Resources Board, April 1975.

"Staff Report - Public Hearing to Consider Fuel Evaporative Emission Regulations for Light-Duty Vehicles (75-7-6)," California Air Resources Board, April 1975.

"Staff Report - Reconsideration of Exhaust Emission Standards for 1977 and Subsequent Model-Year Heavy-Duty Engines (75-7-2)," California Air Resources Board, April 1975.

"Staff Report - Exhaust Emission Standards for 1977 Model-Year Light-Duty Vehicles (75-5-2)," California Air Resources Board, March 1975.

"Smog: A Report to the People," Caltech Environmental Quality Lab, 1972.

14. Gary Rubenstein (Response to CBD Witness Bill Powers)

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In the Matter of: Application for Certification for the PUENTE POWER PROJECT	Docket No. 15-AFC-01 EXPERT DECLARATION OF GARY RUBENSTEIN IN RESPONSE TO OPENING TESTIMONY OF CBD WITNESS BILL POWERS

I, Gary Rubenstein, declare as follows:

1. I am employed by Sierra Research, which has been retained by the Applicant to conduct certain analyses associated with the proposed Puente Power Project (Project or Puente) and am duly authorized to make this declaration.

2. I earned a Bachelor of Science Degree in Engineering from the California Institute of Technology in 1973. I have over 44 years of experience regarding the evaluation of air quality and public health impacts, including impacts associated with greenhouse gas emissions, and related issues. A copy of my current curriculum vitae is attached to this declaration as Attachment A. Based on my education, training and experience, I am qualified to provide expert testimony as to the matters addressed herein.

3. Except where stated on information and belief, the facts set forth herein are true of my own personal knowledge, and the opinions set forth herein are true and correct articulations of my opinions. If called as a witness, I could and would testify competently to the

facts and opinions set forth herein and in the other Applicant's Exhibits identified herein.

4. I have reviewed the Opening Testimony of Bill Powers filed by Intervenor Center for Biological Diversity (CBD) (CBD Exhibit No. 7000) ("Powers Testimony") (CEC TN #215440-1). Without waiving any rights that Applicant has to raise appropriate objections to the Powers Testimony during evidentiary hearings, I hereby respond to certain of the arguments raised therein.

5. Mr. Powers states "Since 2010, the capacity factors of combined cycle units in California have been declining, while the capacity factors of simple cycle gas turbines have been increasing, as shown in Table 1. During this timeframe the capacity factor of aging coastal steam units was relatively stable, at 5.4 percent in 2010 and 5.3 percent in 2014. What this means from a GHG emissions standpoint is that lower efficiency simple cycle gas turbines are incrementally displacing the output of higher efficiency combined cycle gas turbines, and more GHG emissions are being emitted on average from gas-fired generation in California."[1] I disagree.

6. Because the capacity factor information cited by Mr. Powers is very general and lacks specific information regarding the reason for the change in the combined cycle and simple cycle unit capacity factors during the period from 2010 to 2014, it is impossible to conclude from this information that simple cycle units are displacing combined cycle units. These values are a function of a number of factors, including the quantity and consistency of hydroelectric, wind and solar energy, as well as fluctuations in demand due to weather conditions. The presence or absence of additional simple cycle units on the grid has little to do with the capacity factor values cited by Mr. Powers, since units are dispatched based on economic and reliability needs and are not based on the number of units connected to the grid.

7. In addition, the document cited in Mr. Powers' testimony does not support his conclusion that simple cycle units are displacing combined cycle units. The following is

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[1] CEC TN #215440-1, CBD Exhibit 7000, Section IV.A, page 4.

from the document cited in Mr. Powers' testimony and discusses the differences between the annual operation of combined cycle (CC) units compared to peaker units:[2]

> *The capacity factors (CFs) shown in Table 3 give an overview of how often California's fleet of natural gas power plants operated each year. A CF is the ratio of electric generation over a selected period divided by the maximum potential output over the same period. On average, California's CC and cogeneration plants operated at 52 percent of the rated nameplate capacity, while aging and peaker gas plants operated at 5 percent CFs. This difference is to be expected based on an expectation of minimizing fuel costs by running California's more efficient CC plants and leaving the inefficient peaking and aging plants primarily for voltage support and local reliability. For example, the newly constructed 828 MW simple-cycle Marsh Landing Generating Station in Antioch (Contra Costa County), included in the peaker category, operated at less than a 1 percent CF over the past two years, while the similarly new 640 MW CC Russell City Energy Center in Hayward (Alameda County) operated at a 40 percent CF. These two examples illustrate the extreme operational differences between peaker and CC power plants.*

8. Mr. Powers attempts to support his assertion by presenting a table showing capacity factors for California combined cycle and simple cycle units.[3] This table is reproduced below, with the addition of greenhouse gas emissions reported by the California Air Resources Board for these units.

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[2] CEC TN #215440-5, CBD Exhibit 7005: CEC, Thermal Efficiency of Gas-Fired Generation in California: 2015 Update, March 2016, Figure 6, page 16.

[3] CEC TN #215440-1, CBD Exhibit 7000, Table 1, page 4.

Reproduced Table 1. 2010-2014 capacity factors for California combined cycle and simple cycle units

Unit Type	Capacity Factor				
	2010	2011	2012	2013	2014
Combined Cycle	59.9%	59.4%	57.1%	56.0%	54.7%
Simple Cycle	3.2%	3.6%	4.9%	4.7%	5.9%
	Non-Biogenic Greenhouse Gas Emissions from In-State Energy Production (MMtCO2e)[4]				
Total	33.4	22.7	33.9	33.0	34.5

One element of Mr. Powers' assertion was that "more GHG emissions are being emitted on average from gas-fired generation in California" as a result of the increasing capacity factors for simple cycle turbines. The available data indicate that this is not the case. As shown in the table above, the trend in non-biogenic GHG emissions associated with in-state electricity production by combined cycle and simple cycle gas-fired plants shows no correlation with the capacity factors for either combined cycle or simple cycle units. The 2015 GHG emissions from these sources declined slightly from 2014 levels, to 34.1 MMtCO2e. The total GHG emissions from in-state electricity production vary based on a number of factors; the number of simple cycle or combined cycle units available on the grid is not one of them.

9. In support of his conclusion that lower efficiency simple cycle gas turbines are incrementally displacing higher efficiency combined cycle gas turbines Mr. Powers states "This translates into a decline in the thermal efficiency of gas-fired generation in California, which is reflected in a rising 'heat rate.' As shown in Table 2, the average heat rate of gas-fired power plants in California increased from 7,634 Btu/kWh in 2010 to 7,750 Btu/kWh in 2014."[5]

10. Mr. Powers' conclusion regarding a decline in thermal efficiency is not

[4] From https://www.arb.ca.gov/cc/reporting/ghg-rep/reported-data/ghg-reports.htm. Data reflect in-state generation, excluding cogeneration.

[5] CEC TN #215440-1, CBD Exhibit 7000, Section IV.A, page 4.

supported by the data cited. As shown by the data in Mr. Powers' Table 2, there is no clear decline in the thermal efficiency (as represented by heat rates) of natural gas-fired power plants in California. For example, the data in Mr. Powers' testimony show that the heat rate of natural gas fired plants in California increased from 2010 to 2011, but then decreased from 2011 through 2013.[6] As the heat rates decrease the thermal efficiency increases. If Mr. Powers had included cogeneration plants in the data he cited,[7] he would have shown further fluctuations in the heat rate/thermal efficiency of natural gas-fired power plants in California: a decrease in thermal efficiency from 2009 to 2010, an increase from 2010 to 2011, a decrease from 2011 to 2012, a decrease from 2012 to 2013, and an increase from 2013 to 2014. As I indicate above, there are a number of factors that influence the decisions to dispatch simple cycle or combined cycle units in California; the number of such units connected to the grid is not one of those factors. In fact, based on the data cited in Mr. Powers' testimony, what <u>is</u> clear is that during the period from 2001 to 2014 there has been a significant improvement in overall thermal efficiency for natural gas-fired power plants with heat rates decreasing from 10,325 Btu/KWh in 2001 to 8,513 Btu/KWh in 2014.

11. Mr. Powers states "Puente will emit 1,149 lb CO2/MWh. In contrast, SCE grid power emitted only 506 lb CO2/MWh in 2015. The Puente GHG footprint is more than double the average SCE GHG grid power footprint of 506 lb CO2/MWh." [8] This comparison is meaningless; the real question is what impact will the Project's operation have on average GHG emissions from the grid? As is clearly demonstrated in the FSA,[9] the answer is that the Project will reduce GHG emissions from electricity production in California.[10]

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[6] CEC TN #215440-1, CBD Exhibit 7000, Section IV.A, Table 2, page 5.

[7] CEC TN #215440-5, CBD Exhibit 7005: CEC, Thermal Efficiency of Gas-Fired Generation in California: 2015 Update, March 2016, Table 3, p. 4.

[8] CEC TN #215440-1, CBD Exhibit 7000, Section IV.B, page 5.

[9] CEC TN #214712, FSA Appendix AIR-1. "Because the project would displace less-efficient generation resources, the addition of Puente would contribute to a reduction in California GHG emissions and the average GHG emission rate."

[10] CEC TN #214712, FSA, page 4.1-127.

12. Mr. Powers' assertion is also incorrect because his calculation of the GHG emission rate of 1,149 lb CO2/MWh for the Project is based on an incorrect heat rate of 9,819 Btu/kWh. As shown in the FSA, the Project's GHG emission rate is approximately 1,067 CO2 lbs/MWh (0.484 CO2 MT/MWh).[11]

13. Mr. Powers states: "Figure 1 is a sample of the CAISO '24-hour ahead' and '1-hour ahead' forecasts with the actual demand for January 16, 2017. There is no need for dispatching units like Puente from cold start to full load in 10 minutes when the ramping demand is accurately predictable in advance and more efficient gas-fired resources can be scheduled to meet the ramping demand. If they are already online, they can simply adjust their output when they are already online to meet this demand."[12] Mr. Powers over-simplifies how "easy" it is to match the "accurately predictable" ramping demand. Based on this simplistic argument, there would be no need for quick start/high ramp rate peaking units anywhere on the grid. The fact is that CAISO, the CPUC, and California's electric utilities continue to see a role for quick start/high ramp rate units to support the integration of increasing amounts of intermittent renewable generation.

14. Mr. Powers states "The gas-fired generation role being described is applicable to the CAISO control area as a whole and is not specific to the Big Creek/Ventura LCA. A gas fired generator located anywhere in Southern California, and potentially anywhere in California, could serve this ramping/load following need."[13] Once again Mr. Powers over-simplifies the issue and his conclusion is inconsistent with the facts, and the real-time, transmission constraints that CAISO must manage.

15. Mr. Powers states "[t]he fuel efficiency of Puente is about 18 percent better than that of Mandalay Unit 2, 9,819 Btu/kWh vs 11,572 Btu/kWh. However, Puente is permitted to operate six times more frequently, 30 percent capacity factor, than the actual

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[11] CEC TN #214712, FSA, page 4.1-153 and Greenhouse Gas Table 4.

[12] CEC TN #215440-1, CBD Exhibit 7000, Section IV.C, page 7.

[13] CEC TN #215440-1, CBD Exhibit 7000, Section IV.C, page 9.

average operating rate of Mandalay 2 or Mandalay 1 (5 percent capacity factor). As a result, far more GHGs will be emitted from Puente than from existing operation of Mandalay Units 1 & 2 if Puente operates at or near its assumed capacity factor."[14] Mr. Powers' calculation of the Puente heat rate of 9,819 Btu/kWh is incorrect. Mr. Powers incorrectly calculates this heat rate using the maximum heat input for the P3 gas turbine generator under any ambient condition (a cold ambient day) and a net nominal net output of 262 MW.[15] As shown in the FSA, the heat rate for Puente at more typical, average ISO conditions is approximately 9,149 Btu/kWh (HHV) based on gross output.[16] This translates into an ISO heat rate of approximately 9,250Btu/kWh (HHV) based on net output.[17]

16. Mr. Powers' comparison between the annual capacity factors of MGS Units 1 and 2 and P3 is misleading because it compares the actual historical annual capacity factor of MGS Units 1 and 2 to the maximum allowable annual capacity factor for Puente. Based on the allowable annual operating/emission limits in the current Title V permit issued by the VCAPCD for MGS Units 1 and 2,[18] these units are allowed to operate with a maximum annual capacity factor of 100% compared to Puente, which under the FDOC/FSA[19,20] is limited to an annual capacity factor of approximately 24.5%. The allowable operation of MGS Units 1 and 2 is 20 times larger than the 5% capacity factor that Mr. Powers cites for those units. Mr. Powers also neglects to mention that the maximum hourly generation of Puente (275 MW

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[14] CEC TN #215440-1, CBD Exhibit 7000, Section IV.D, page 10.

[15] CEC TN #215440-1, CBD Exhibit 7000, page 5, footnote 13.

[16] CEC TN #214712, FSA, page 4.1-153, Greenhouse Gas Table 4.

[17] Based on a total auxiliary load of approximately 3 MW for the P3 gas turbine generator. 9,149 Btu/kWh x (275 MW/272 MW) = 9,250 Btu/kWh.

[18] Part 70 Permit, Permit Number 00013, Permit Term January 1, 2014 to December 31, 2018, Mandalay Generating Station, available at http://www.vcapcd.org/pubs/Engineering/permits2000/TitleV2000/Mandalay-Generating-Station-Permit-No-00013-July-10-%202015.pdf.

[19] CEC TN #214005-13, VCAPCD FDOC, Condition 48, annual limit of 2150 operating hours per year, (2150 hrs/8760 hrs) = 24.5%.

[20] CEC TN #214712, FSA, AQ-48, annual limit of 2150 operating hours per year, (2150 hrs/8760 hrs) = 24.5%.

gross)[21] is approximately 37% lower than the 435.2 MW (gross)[22] output of MGS Units 1 and 2, and that the allowable annual output of Puente (591 GWH gross[23]) is approximately 84% lower than the allowable annual output of MGS Units 1 and 2 (3,812 GWH[24]).

17. With regards to comparing the actual average capacity factor of MGS Units 1 and 2 to the expected actual average capacity factor of Puente, as discussed in the FSA[25] based on a review of annual capacity factors in Big Creek Local Reliability Area during the period from 2009 to 2015 the actual annual capacity factors of MGS Units 1 and 2 range from a low of approximately 1.4% (MGS Unit 1 2011) to a high of approximately 8.2% (MGS Unit 2, 2009). Based on this data, the expected actual average capacity factor of Puente would have been approximately 7.9% (based on a five year average) which falls within the range of actual annual capacity factors for MGS Units 1 and 2. With an expected actual annual capacity factor for Puente in the same range as the existing MGS Units 1 and 2, and given the higher efficiency/lower GHG emission rate of Puente compared to MGS Units 1 and 2 on mass per MWh basis, there would not be an increase in GHGs for Puente compared to MGS Units 1 and 2. This conclusion is confirmed in the FSA with regards to the overall GHG emission benefits of P3.[26]

18. Mr. Powers states "[t]he FSA cites to three different assumed capacity factors for Puente: 30 percent, 24 percent, and 11 percent. Air emissions and GHG emissions would be proportional to the capacity factor. If Puente operates at a capacity factor of 30 percent instead of 11 percent, both air emissions and GHG emissions will be nearly three times greater… However, apparently to ease the financial burden on the Applicant of procuring offset credits,

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[21] CEC TN #214712, FSA, page 4.1-153 and Greenhouse Gas Table 4.

[22] CEC TN #214712, FSA, page 4.1-153 and Greenhouse Gas Table 4.

[23] 275 MW (gross, ISO) x 2150 hrs/year of operation.

[24] 435.2 MW x 8760 hrs/year of operation.

[25] CEC TN #214712, FSA, page 4.1-49 and Table Air Quality Table 29.

[26] CEC TN #214712, FSA, page 4.1-156.

Commission staff recommend offsetting air emissions based on an assumed capacity factor of 11 percent. If Commission staff conservatively conclude that Puente will not operate with a capacity factor of more than 11 percent, and impose enforceable mitigation requirements on the basis of this conclusion, then Puente must be subject to an enforceable annual fuel consumption limit that is equivalent to an 11 percent capacity factor."[27]

19. Mr. Powers confuses VCAPCD emission offset requirements (which, by regulation, are based on maximum allowable operations) and CEQA mitigation requirements (which, by regulation, are based on reasonably foreseeable impacts). As discussed in the FSA, based on the applicable VCAPCD New Source Review (NSR) regulation net emission calculation procedures, which account for the maximum allowable annual operation/annual capacity factor of approximately 24.5%, the Project only triggers NSR emission offset requirements for NOx.[28] With regards to CEQA mitigation, the FSA clearly discusses the calculation procedure used to establish the staff's proposed SOx and $PM_{10}/PM_{2.5}$ mitigation requirements, which are based on the reasonably foreseeable impacts of the Project.[29] Mr. Powers has not provided any data to support a conclusion that the CEC Staff has made an erroneous projection of the reasonably foreseeable operation of the Project, nor has he provided any regulatory basis for his assertion that additional mitigation should be required to reduce project air quality impacts to a less than significant level.

20. Mr. Powers states: "[t]he use of ERCs, which could provide 100 percent of the mitigation under COC AQSC9, does not assure mitigation is local and contemporaneous. Emission reductions associated with ERCs typically do not occur contemporaneously with project emissions, but rather decades before the project and thus are part of the project baseline."[30]

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[27] CEC TN #215440-1, CBD Exhibit 7000, Section V.A., pp. 11-12.
[28] CEC TN #214712, FSA, page 4.1-48.
[29] CEC TN #214712, FSA, pages 4.1-48 to 4.1-53.
[30] CEC TN #215440-1, CBD Exhibit 7000, Section IV.B.1.a, page 13.

21. Emission offsets are a well-established option for satisfying CEQA mitigation requirements in California. The fact that the emission reductions occurred prior to the construction and operation of the Project is not a bad thing – early reductions in emissions are always preferable, and the emission offset program was designed to encourage such early reductions.

22. Mr. Powers states: "[w]hile ERCs are legal instruments under the federal Clean Air Act for long-term air quality planning, no demonstration of actual present-day net air quality benefits can be produced as the associated emission reductions have occurred in the past and are therefore part of the baseline of existing air quality. Instead, the City and affected local communities will experience real-time, present-day emissions increases which will increase the exposure of residents to elevated concentrations of PM10/PM2.5 and SOx and will jeopardize the County's future compliance and progress towards attainment of the state PM10 ambient air quality standard."[31]

23. The pollutants for which the CEC is requiring mitigation – SO2 and PM10/PM2.5 – are regional in their impacts, and regional mitigation is both encouraged and allowed for these pollutants. Mr. Powers' allegation that the Project's emissions of these pollutants will "jeopardize the County's future compliance and progress towards attainment of the state PM10 ambient air quality standard" is completely unsupported. In fact, most of the state of California is nonattainment for that standard, and has been so since the standard was adopted.

24. Mr. Powers states: "[e]mission reduction projects under the Carl Moyer Program must have a minimum life of only three years. The emissions that must be mitigated will occur for the life of the Project, which is 30 years or more. Therefore, COC AQ-SC9 must be modified to clearly require emission offset projects that cover the entire lifetime of the

[31] CEC TN #215440-1, CBD Exhibit 7000, Section IV.B.1.a, pages 13 and 14.

Project."[32]

25. As noted in Mr. Powers' testimony, the Carl Moyer Program typically results in the retrofit or replacement of sources such as off-road and on-road heavy duty engines, emergency vehicles, portable and stationary agricultural sources, locomotives, and marine vessels. In the case of the replacement of older equipment with new units under the Carl Moyer Program, the net benefit is permanent because the older higher emitting equipment is replaced with a new cleaner unit and permanently removed from the fleet. The same is true for engine repower projects under the Carl Moyer Program: the net benefit is permanent because the older higher emitting engine is replaced with a new cleaner engine and permanently removed from the fleet.

26. Mr. Powers states: "[t]he air dispersion modeling performed by the Sierra Club, for example, indicates that NO2 emissions exceed ambient air quality standards for NO2. The proposed ERCs would not mitigate these impacts because ERCs are emission reductions that occurred in the past and thus do not reduce future increases in NO2 emissions."[33]

27. As discussed in the Applicant's response to comments on the VCAPCD Preliminary Determination of Compliance (PDOC) filed by the Sierra Club, the Sierra Club's 1-hr NO2 modeling analysis comes to the conclusion that the Project's modeled impacts exceed ambient air quality standards for NO_2 due mainly to the use of less refined modeling approaches compared to methods used by the Applicant, the Staff, and the VCAPCD.[34] This conclusion is affirmed in the FSA:

> ***Air Quality Appendix Air-3 Table 6*** *shows that, with a more refined Tier 3 modeling analysis using PVMRM, and a more refined pairing of modeled impacts and background concentrations, Puente with existing sources would not exceed the 1-hour NO2 CAAQS or NAAQS during commissioning, startups/shutdowns, or normal operations. Therefore,*

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[32] CEC TN #215440-1, CBD Exhibit 7000, Section IV.B.1.c, page 15.

[33] CEC TN #215440-1, CBD Exhibit 7000, Section IV.B.1.d, page 15.

[34] CEC TN #213482, Applicant's Exhibit 1085, response to Comment 30.

staff believes that Ms. Sears' statement that the project will cause violations of 1-hour NO2 CAAQS and NAAQS is incorrect. [35]

28. I hereby sponsor this declaration into evidence in these proceedings as Applicant's Exhibit No. 1139.

Executed on January 24, 2017, at Sacramento, California.

I declare under penalty of perjury of the laws of the State of California that the foregoing is true and correct.

Gary Rubenstein

[35] CEC TN #214712, FSA, Air Quality Appendix AIR-3, page 4.1-200.

ATTACHMENT A

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Résumé

Gary S. Rubenstein

Education

1973, B.S., Engineering, California Institute of Technology

Professional Experience

8/81 to present — Senior Partner
Sierra Research

As one of the founding partners of Sierra Research, responsibilities include project management and technical and strategy analysis in all aspects of air quality planning and strategy development; project licensing and impact analysis; emission control system design and evaluation; rulemaking development and analysis; vehicle inspection and maintenance program design and analysis; and automotive emission control design, from the initial design of control systems to the development of methods to assess their performance in customer service. As the Partner principally responsible for Sierra Research's activities related to stationary sources, he has supervised the preparation of control technology assessments, environmental impact reports and permit applications for numerous industrial and other development projects.

While with Sierra, Mr. Rubenstein has managed and worked on numerous projects, including preparation of nonattainment plans; preparation and review of emission inventories and control strategies; preparation of the air quality portions of environmental review documents for controversial transportation, energy, mineral industry and landfill projects; preparation of screening health risk assessments and supporting analyses; and the development of air quality mitigation programs. Mr. Rubenstein has managed the preparation of air quality licensing applications for over 18,000 megawatts of generating capacity before the California Energy Commission, and has managed air quality analyses for over 30,000 megawatts of generating capacity in a variety of jurisdictions.

Mr. Rubenstein and his colleagues at Sierra have followed literature related to climate change and the control of greenhouse gas emissions since the early 1990s. The firm's work has focused on understanding the scientific, legal and regulatory basis for the regulation of greenhouse emissions by various jurisdictions in the United States, and on the evaluation of the costs and environmental impacts of alternative regulatory approaches for controlling greenhouse gas emissions.

Mr. Rubenstein has presented testimony and served as a technical expert witness before numerous state and local regulatory agencies, including the U.S. Environmental Protection Agency, California State Legislative Committees, the California Air Resources Board, the California Energy Commission, the California Public Utilities Commission, numerous California air pollution control districts, the Connecticut Department of Environmental Protection, the Hawaii Department of Health, and the Alabama Department of Environmental Management. Mr. Rubenstein has also served as a technical expert on behalf of the California Attorney General and Alaska Department of Law, and has provided expert witness testimony in a variety of administrative and judicial proceedings.

6/79 to 7/81	Deputy Executive Officer California Air Resources Board

Responsibilities included policy management and oversight of the technical work of ARB divisions employing over 200 professional engineers and specialists; final review of technical reports and correspondence prepared by all ARB divisions prior to publication, covering such diverse areas as motor vehicle emission standards and test procedures, motor vehicle inspection and maintenance, and air pollution control techniques for sources such as oil refineries, power plants, gasoline service stations and dry cleaners; review of program budget and planning efforts of all technical divisions at ARB; policy-level negotiations with officials from other government agencies and private industry regarding technical, legal, and legislative issues before the Board; representing the California Air Resources Board in public meetings and hearings before the California State Legislature, the California Energy Commission, the California Public Utilities Commission, the Environmental Protection Agency, numerous local government agencies, and the news media on a broad range of technical and policy issues; and assisting in the supervision of over 500 full-time employees through the use of standard principles of personnel management and motivation, organization, and problem solving.

7/78 – 7/79	Chief, Energy Project Evaluation Branch Stationary Source Control Division California Air Resources Board

Responsibilities included supervision of ten professional engineers and specialists, including the use of personnel management and motivation techniques; preparation of a major overhaul of ARB's industrial source siting policy; conduct of negotiations with local officials and project proponents on requirements and conditions for siting such diverse projects as offshore oil production platforms, coal-fired power plants, marine terminal facilities, and almond-hull burning boilers.

During this period, Mr. Rubenstein was responsible for the successful negotiation of California's first air pollution permit agreements governing a liquefied natural gas terminal, coal-fired power plant, and several offshore oil production facilities.

10/73 to 7/78 Staff Engineer
Vehicle Emissions Control Division
California Air Resources Board

Responsibilities included design and execution of test programs to evaluate the deterioration of emissions on new and low-mileage vehicles; detailed analysis of the effect of California emission standards on model availability and fuel economy; analysis of proposed federal emission control regulations and California legislation; evaluation of the cost-effectiveness of vehicle emission control strategies; evaluation of vehicle inspection and maintenance programs, and preparation of associated legislation, regulations and budgets; and preparation of detailed legal and technical regulations regarding all aspects of motor vehicle pollution control. Further duties included preparation and presentation of testimony before the California Legislature and the U.S. Environmental Protection Agency; preparation of division and project budgets; and creation and supervision of the Special Projects Section, a small group of highly trained and motivated individuals responsible for policy proposals and support in both technical and administrative areas (May 1976 to July 1978).

Credentials and Memberships

Air & Waste Management Association (Past Chair, Board of Directors, Golden West Section; Past Chair, Board of Directors, Mother Lode Chapter)

American Society of Mechanical Engineers

Qualified Environmental Professional, Institute of Professional Environmental Practice, 1994

Selected Publications (Author or Co-Author)

"Multipollutant Approaches to Regulation," presentation at the California Council for Environmental and Economic Balance 2016 Summer Issues Seminar, July 11, 2016.

"Air Quality and Public Health," presentation at the California Council for Environmental and Economic Balance 2016 Summer Issues Seminar, July 13, 2016.

"Overview of the California Environmental Quality Act," presentation for private client, June 2016.

"The Efficacy of Greenhouse Gas Emission Caps at Local Refineries," presentation to the Bay Area Air Quality Management District Advisory Council, April 25, 2016.

“Fundaments of Air Quality Planning and Regulation,” presentation to the Jiangsu Environmental Protection Department, October 20, 2015.

“Carbon Pollution Standards for New, Modified and Reconstructed Power Plants – Final Rule and Impacts,” presentation for private clients, August 27, 2015.

“Understanding the Supreme Court’s MATS Ruling,” presentation for private clients, July 15, 2015.

“OEHHA’s New Hot Spots Exposure and Assessment Guidelines,” prepared for private client, October 30, 2014.

“Diesel Particulate Matter Regulation and Health Impacts,” presentation at the 2012 Railroad Environmental Conference on October 16, 2012, in Champagne-Urbana, Illinois.

“Using Screening Tools to Identify Priority Communities,” presentation at the California Council for Environmental and Economic Balance 2012 Summer Issues Seminar on July 16, 2012, at Squaw Valley, California.

“Slogging Through the Modeling Maze: New National Ambient Air Quality Standards for NO_2, SO_2 and $PM_{2.5}$,” presentation to the Air & Waste Management Association on February 12, 2012, in Sacramento, California.

“Climate Change Regulation and Environmental Justice,” presentation at the California Council for Environmental and Economic Balance 2011 Summer Issues Seminar on July 11, 2011, at Squaw Valley, California.

“EPA Greenhouse Gas Tailoring Rule,” presentation to the Air & Waste Management Association on February 16, 2011, at Bakersfield, California.

“Non-Traditional ERCs – Giving Credit Where Credit is Due,” presentation to the California Desert Air Working Group on November 17, 2010, at Laughlin, Nevada.

“Sensitivity and Vulnerability: Community Health Factors as Part of Environmental Decision Making,” presentation at the California Council for Environmental and Economic Balance 2010 Summer Issues Seminar on July 19, 2010, at Squaw Valley, California.

“Evaluation of CTM-039 Dilution Method for Measuring PM_{10}/$PM_{2.5}$ Emissions from Gas-Fired Combustion Turbines,” August 20, 2009.

“Application of SCR to Small Sources: A Case Study” presentation to the Air & Waste Management Association on January 29, 2009, in Diamond Bar, California.

"Dealing with the Scarcity of PM Offsets," presentation to Law Seminars International: Air Quality Regulation in California on April 15, 2008, in Los Angeles, CA.

"Field Demonstration of a Dilution-Based Particulate Measurement System," presentation to Stationary Source Sampling and Analysis for Air Pollutants on March 5, 2008, in San Diego, CA.

"The California Global Warming Solutions Act of 2006 – Implementation Considerations," presentation to Law Seminars International: Energy in California 2007 on September 17, 2007, in San Francisco, CA.

"Preparing for and Conducting Air Quality Compliance Audits," presentation to California Desert Air Working Group on October 19, 2006, in Big Bear Lake, CA.

"Test Results from Sugar Cane Bagasse and High Fiber Cane Co-fired with Fossil Fuels," Biomass and Bioenergy, Vol. 30, Issue 6. pp. 565-574. June 2006.

"Gas Turbine Particulate Matter Emissions – Update," Presentation to ASME/EIGTI Turbo Exp. on June 9, 2005 in Reno, NV.

"Gas Turbine Startup Emissions," Presentation to ASME/IGTI Turbo Expo on June 9, 2005 in Reno, NV.

"Gas Turbine Particulate Matter Emissions – Update," Presentation to ASME/IGTI Turbo Expo on June 18, 2003 in Atlanta, GA.

"Sources of Uncertainty When Measuring Particulate Matter Emissions from Natural Gas-Fired Combustion Turbines," presentation to Air & Waste Management Association on March 30, 2001 in San Diego, CA.

"An Analysis of the Effect on Emissions of Allowing Drive-Thru Service Lanes," Sierra Research Report No. SR97-11-01, prepared for California Business Properties Association, November 10, 1997.

"Searles Valley Air Quality Study (SVAQS) Final Report," Sierra Research Report No. SR94-02-01, prepared for North American Chemical Company, February 1994.

"Regulatory Strategies for Reducing Emissions from Marine Vessels in California Waters," Sierra Research Report No. SR91-10-01, prepared for the California Air Resources Board, October 4, 1991.

"An Analysis of the Effect on Emissions of Eliminating Drive-Thru Services Lanes," Sierra Research Report No. SR91-07-03, prepared for California Restaurant Association, July 25, 1991.

“Development of the CALIMFAC California I/M Benefits Model,” Sierra Research Report No. SR-91-01-01, prepared for the California Air Resources Board, Agreement No. A6-173-64, January 1991.

“Criteria Pollutant Emission Inventory for the Coachella Valley Study Area,” Sierra Research Report No. SR90-11-01, prepared for South Coast Air Quality Management District, November 1990.

“User’s Guide to the CALIMFAC California I/M Benefits Model,” Prepared for the California Air Resources Board, May 1990.

“Potential Emissions and Air Quality Effects of Alternative Fuels – Final Report,” Sierra Research Report No. SR89-03-04, prepared for Western States Petroleum Association, March 28, 1989.

“Interprecursor Offset Ratios for Ozone in the Searles Valley,” Sierra Research Report No. SR89-03-02, prepared for Kerr-McGee Chemical Company, March 17, 1989.

“An Assessment of the Quality of California’s Air Pollution Emissions Inventory,” Sierra Research Report No. SR88-05-01, prepared for Western Oil and Gas Association, May 1988.

“Trends in Visibility-Related Emissions Affecting the R-2508 Restricted Airspace,” Sierra Research Report No. SR88-05-02, prepared for Western Oil and Gas Association, May 1988.

“Volume I, Executive Summary: Impacts of Air Quality Regulations on Visibility-Related Emissions in the California R-2508 Restricted Airspace,” Sierra Research Report No. SR88-03-02, prepared for Western Oil and Gas Association, March 1988.

“Volume II, Determination of California Air Basins Which Can Affect Visibility in the R-2508 Restricted Airspace,” Sierra Research Report No. SR88-03-03, prepared for Western Oil and Gas Association, March 1988.

“Air Quality Impact Analysis for the Soledad Biomass Resource Recovery Project,” Sierra Research Report No. SR87-10-01, prepared for Western Forest Power Corp., October 1987.

“Air Quality Impact Analysis for the Honey Lake Biomass Power Plant Project,” Sierra Research Report No. SR87-05-01, prepared for GeoProducts-Zurn/NEPCO, May 22, 1987.

“1986 Update to the Kern County Nonattainment Area Plan,” Sierra Research Report No. SR86-03-01, prepared for Kern County Air Pollution Control District and Kern Council of Governments, March 1986.

"An Analysis of Test Results on Grancor Pollution Control Devices for Automotive Retrofit Programs," Sierra Research Report No. SR85-09-01, prepared for Grancor, September 1985.

"Temperature Correction Factors for California's Motor Vehicle Emissions Model," Sierra Research Report No. SR85-06-01, prepared for the California Air Resources Board, June 1985.

"Critique of the EPA I/M Benefits Model for 1980 and Older Model Cars," Sierra Research Report No. SR85-06-02, prepared for the California Air Resources Board, June 1985.

"Emission Factors for 1980 and Later Model Year California Passenger Cars and Light-Duty Trucks," Sierra Research Report No. SR85-06-03, prepared for the California Air Resources Board, June 1985.

"Technology Assessment for Light-Duty Vehicle Compliance with a 0.4g/m NOx Standard," Sierra Research Report No. SR85-06-04, prepared for the California Air Resources Board, June 1985.

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"Critical Metal Consumption in Automotive Catalysts – Trends and Alternatives," Sierra Research Report No. SR83-12-01, prepared for Congress of the United States, Office of Technology Assessment, December 1983.

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"The Effect of Clean Air Act Amendments on High Altitude Passenger Cars," Sierra Research Report No. SR81-09-01, September 1981.

"Staff Report - Public Meeting to Discuss Proposed Guidelines for the Control of Emissions from Coal-Fired Power Plants (81-11-2)," California Air Resources Board, June 1981.

"Staff Report - Public Hearing to Consider Amendments to Title 13, Section 1960.1, CAC, Regarding Exhaust Emission Standards and Test Procedures for 1983 and Subsequent Model Passenger Cars, Light-Duty Trucks and Medium-Duty Vehicles," California Air Resources Board, May 1981.

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"Staff Report - A Proposed Air Resources Board Policy Regarding Incineration as an Acceptable Technology for PCB Disposal," California Air Resources Board, March 1981.

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"Staff Report - Public Hearing to Consider Amendments to Title 13, Section 1956.7, CAC, Regarding Exhaust Emission Standards and Test Procedures for 1984 and Subsequent Model Heavy Duty Engines (81-1-1)," California Air Resources Board, January 1981.

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"Staff Report - Public Hearing to Consider Confirmation of Emergency Adoption of Section 1960.4, Title 13, CAC, Regarding Special NOx Standards for Small-Volume Manufacturers (80-25-1)," California Air Resources Board, December 1980.

"Staff Report - Public Hearing to Consider Adoption of California Assembly- Line Test Procedures for Certain 1982 Model Year Vehicles and Adoption of Section 2060, Title 13, CAC, Incorporating the Test Procedures (80-26-4)," California Air Resources Board, December 1980.

"Staff Report - Public Hearing to Consider Repeal of 1955-1965 Model Year Motor Vehicle Exhaust Retrofit Emission Control Requirements - Title 13, CAC Section 2007 (80-20-2)," California Air Resources Board, October 1980.

"Staff Report - Public Hearing to Consider Amendments to Rule 424 of the Kern County APCD Controlling Emissions of Sulfur Oxide from Steam Generators Used in Oil Field Operations," California Air Resources Board, October 1980.

"Staff Report - Proposed Amendments to Title 13, CAC, Sections 2035-42, Regarding Warranty of Emissions-Related Components of Vehicles (80-18-1)," California Air Resources Board, September 1980.

"Staff Report - Proposed Amendment to Title 13, CAC Regarding Standards and Test Procedures for Modified Vehicles - 1981 and Subsequent Passenger Cars, Light-Duty Trucks and Medium-Duty Vehicles," California Air Resources Board, September 1980.

"Staff Report - Public Meeting to Discuss Issues Related to Power Plant Siting," California Air Resources Board, September 1980.

"Staff Report - Emergency Public Hearing to Consider Amendments to Title 13, CAC, Regarding Exhaust Emission Standards for Oxides of Nitrogen (NOx) from Vehicles Produced by Small Manufacturers for the 1982-1986 Model Years of Passenger Cars, Light-Duty Trucks and Medium- Duty Vehicles," California Air Resources Board, August 1980.

"Staff Report - Emergency Public Hearing to Consider Adoption of a Particulate Exhaust Emission Standard for 1982 and Subsequent Model Year Light-Duty Diesel Vehicles and to Consider Amending the 1982 NOx Exhaust Emission Standard for Those Vehicles (80-15-2)," California Air Resources Board," August 1980.

"Cogeneration Technology and Resource Recovery Status Report," California Air Resources Board, August 1980.

"Staff Report - Response to the Motorcycle Manufacturers' Petition Requesting the Board Reevaluate the 1.0 Gram Per Kilometer Exhaust Emission Standard for 1982 and Subsequent Model Year Motorcycles (80-13-3)," California Air Resources Board, July 1980.

"Staff Report - Inventory of Potential Cogeneration Technology and Resource Recovery Projects Planned or Proposed to Be Constructed Before 1987," California Air Resources Board, July 1980.

"Staff Report - Public Hearing to Consider Proposed Amendments to Kern County APCD Rule 424 - Sulfur Compounds from Oil Field Steam Generators," California Air Resources Board, May 1980.

"Staff Report - Public Hearing to Consider Amending the Rules and Regulations of Imperial County Air Pollution Control District, Los Angeles County Air Pollution Control District and San Bernardino County Air Pollution Control District," California Air Resources Board, May 1980.

"Staff Report - Public Hearing to Consider Amendments to Title 13, CAC, Regarding the Extension of California's 1980 Heavy-Duty Engine Emission Standards through the 1983 Model Year," California Air Resources Board, May 1980.

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Nitrogen from Oil Fired Steam Generators," California Air Resources Board, March 1980.

"Staff Report - Public Hearing to Consider Proposed Amendments to Title 13 of the Administrative Code and to the Exhaust and Evaporative Emission Standards and Test Procedures for 1981 and Subsequent Model year Passenger Cars, Light-Duty Trucks and Medium-Duty Vehicles," California Air Resources Board, March 1980.

"Air Pollution Aspects of Resource Recovery Facilities," California Air Resources Board, March 1980.

"Memorandum of Agreement - Hondo 'A' Development Santa Ynez Unit, Santa Barbara Channel between The State of California, County of Santa Barbara and Santa Barbara Air Pollution Control District and Exxon Company, U.S.A.," California Air Resources Board, February 1980.

"A Report on California's Certificate of Compliance Program prepared for the California Legislature Joint Legislative Budget Committee in accordance with the requirements of the Supplemental Report on Item 194 of the Committee of Conference on the Budget," California Air Resources Board, December 1979.

"Status Report on the Need for/and Feasibility of a 0.4 NOx Standard for Light Duty Motor Vehicles," California Air Resources Board, December 1979.

"Staff Report - Status of NOx Control for Steam Generators and Availability of NOx Trade-offs in Kern County (79-27-1b)," California Air Resources Board, November 1979.

"Staff Report - Public Meeting to Consider Model Rule for the Control of Oxides of Nitrogen Emissions from Stationary Internal Combustion Engines (79-28-2)," California Air Resources Board, November 1979.

"First Annual Report to the Legislature on the Mandatory Vehicle Inspection Program (MVIP)," California Air Resources Board, October 1979.

"Chapter 27, California Lead Control Strategy - Revision to the State of California Implementation Plan for the Attainment and Maintenance of Ambient Air Quality Standards," California Air Resources Board, September 1979.

"Staff Report - Public Hearing to Reconsider the Adoption by the Board into the Regulations of the Kern County Air Pollution Control District on March 23, 1979, of Rule 424, for the Control for Emissions of Sulfur Compounds from Steam Generators Used in Oil Field Operations," California Air Resources Board, August - September 1979.

"Staff Report - Public Hearing to Consider the Adoption of Chapter 27 as a Revision to the State of California Implementation Plan for the Attainment and Maintenance of the National Ambient Air Quality Standards for Lead," California Air Resources Board, August 1979.

"Staff Report - Public Hearing to Consider Amendment of the State Regulation Which Limits the Lead Content of Gasoline Sold in California (79-22-1)," California Air Resources Board, August 1979.

"Staff Report – Alcohols and Alcohol/Gasoline Blends as Motor Fuels," California Air Resources Board, August 1979.

"Centralized Vehicle Inspection/Maintenance in California," California Air Resources Board, May 1979.

"Staff Report - Public Hearing to Consider Changes to the Air Resources Board's Standards and Test Procedures for 1980 and Subsequent Model Passenger Cars, Light-Duty Trucks, and Medium-Duty Vehicles," California Air Resources Board, April 1979.

"Staff Report - Public Hearing to Consider Proposed Changes in the Regulations of the Air Resources Board Regarding Predelivery Inspection and Compliance Test Evaluation," California Air Resources Board, April 1979.

"An Evaluation of California's Private Garage Emissions Inspection Program," California Air Resources Board, March 1979.

"Staff Report - Proposed Rule For Control of Emissions of Sulfur Compounds From Steam Generators and Boilers Used in Oilfield Operations in the Kern County Air Pollution Control District," California Air Resources Board, March 1979.

"Staff Report - Public Hearing to Consider Adoption of a Regulation Controlling Emissions of Sulfur Compounds from Steam Generators Used in Oilfield Operations in the Kern County APCD," California Air Resources Board, March 1979.

"Staff Report - Revisions to the State of California Implementation Plan (SIP) for the Attainment and Maintenance of National Ambient Air Quality Standards - Kings County, Madera County, Merced County, and Tulare County Non-attainment Plans (NAPs)," California Air Resources Board, February 1979.

"Staff Report - Public Meeting to Consider a Proposed Model New Source Review Rule," California Air Resources Board, January 1979.

"Staff Report - Proposed ARB-CEC Joint Policy Statement of Compliance with Air Quality Laws by New Power Plants (79-1-3)," California Air Resources Board, January 1979.

"Staff Report - Public Hearing to Consider Exhaust Standards for the Mandatory Vehicle Inspection Program," California Air Resources Board, September 1978.

"Staff Report - Public Hearing to Consider Proposed Emissions Warranty Regulations (78-3-1)," California Air Resources Board, February 1978.

"Staff Report - Public Hearing to Consider Proposed Highway Cycle Emission Standard for Passenger Cars, Light Duty Trucks, and Medium- Duty Vehicles (78-1-2)," California Air Resources Board, January 1978.

"Staff Report - Public Hearing to Consider Proposed Changes to Motor Vehicle Emission Standards Test Procedures, and Enforcement Programs (77-20-2)," California Air Resources Board, September 1977.

"Staff Report - Surveillance Bibliography of Passenger Cars, Motorcycles, Heavy-Duty and Medium-Duty Vehicles," California Air Resources Board, July 1977.

"Staff Report - Public Hearing on Proposed Changes to Regulations Regarding California Exhaust Emission Standards and Test Procedures for 1980 and Subsequent Model Motor Vehicles (78-9-2)," California Air Resources Board, May 1977.

"Staff Report - Public Hearing on Proposed Changes to Regulations Regarding Allowable Maintenance During New Vehicle Certification of Light-Duty and Medium-Duty Vehicles (77-12-1)," California Air Resources Board, May 1977.

"Staff Report - Public Hearing on Proposed Changes to Regulations Regarding Allowable Maintenance During New Vehicle Certification of Light-Duty and Medium-Duty Vehicles (77-9-2)," California Air Resources Board, April 1977.

"Staff Report - Manganese Fuel Additive MMT (77-9-3)," California Air Resources Board, April 1977.

"Staff Report - Public Hearing to Consider Amendments to the Hydrocarbon Standards and Test Procedures Applicable to 1978 Through 1981 Production Year Motorcycles (77-6-2)," California Air Resources Board, March 1977.

"Staff Report - Status Report on the Mandatory Vehicle Inspection Program (MVIP) (77-4-2)," California Air Resources Board, February 1977.

"Staff Report - Control of Motorcycle Evaporative Emissions and Certification of Motorcycle Fuel Fill Pipes (77-63)," California Air Resources Board, March 1977.

"Staff Report - Public Hearing on Proposed Changes to Regulations Regarding Vehicle Evaporative Emission Standards for 1980 and Subsequent Model Motor Vehicles (76-22-2 c)," California Air Resources Board, November 1976.

"Staff Report - Public Hearing on Proposed Changes to Regulations Regarding Exhaust Emission Standards and Test Procedures for 1979 and Subsequent Model Passenger Cars, Light-Duty Trucks and Medium-Duty Vehicles (76-22-2 a)," California Air Resources Board, November 1976.

"Staff Report - Public Hearing on Proposed Changes to Regulations Regarding Allowable Maintenance During New Vehicle Certification of Light-Duty and Medium-Duty vehicles (76-22-2 b)," California Air Resources Board, November 1976.

"Staff Report - Evaluation of Mandatory Vehicle Inspection and Maintenance Programs," California Air Resources Board, May-August 1976.

"Staff Report - Public Hearing to Consider Proposed Changes to Regulations Regarding Approval of 1978 and Subsequent Model Light-Duty Trucks and Heavy-Duty Engines (76-6-2)," California Air Resources Board, March 1976.

"Staff Report - Public Hearing to Consider Amendments to California Fuel Evaporative Emissions Test Procedures for 1978 and Subsequent Model Gasoline-Powered Vehicles (76-6-3)," California Air Resources Board, March 1976.

"Staff Report - Public Hearing Regarding Amendment of Emission Standards and Test Procedures for Motorcycles (76-1-4)," California Air Resources Board, January 1976.

"Staff Report - Catalyst Service and Replacement Regulations (75-20-2)," California Air Resources Board, October 1975.

"Staff Report - Emergency Action to Amend the New Vehicle Approval Regulations Regarding Catalyst Change (75-18-2)," California Air Resources Board, September 1975.

"Staff Report - Progress Report on Technology to Control Sulfate Emissions from Catalyst-Equipped Vehicles (75-15-2)," California Air Resources Board, August 1975.

"Staff Report - Public Hearing to Consider 1978 Production Motorcycle Emission Standards (75-14-2)," California Air Resources Board, July 1975.

"Staff Report - Consideration of Regulation Change to Extend the Alternate Heavy-Duty Engine Standards for 1977 and Subsequent Years (75-14-3)," California Air Resources Board, July 1975.

"Staff Report - Motorcycle Emission Control Strategies (75-11-4)," California Air Resources Board, June 1975.

"Staff Report - Catalytic Converter Retrofit Program - Used Vehicles Retrofitted with Universal Oil Products Catalytic Converters Final Report," California Air Resources Board, May 1975.

"Staff Report - Estimate of Contribution of Motorcycles to California Air Pollution (75-9-5)," California Air Resources Board, May 1975.

"Staff Report - Public Hearing for Adoption of Proposed Changes to Vehicular Enforcement Regulations Including Recall Procedures (75-9-4)," California Air Resources Board, May 1975.

"Staff Report - Public Hearing to Consider Inspection Specification Regulations in Title 13 -- New Vehicles (continued) (75-9-3a)," California Air Resources Board, May 1975.

"Staff Report - Emergency Action to Delete High Altitude Test Provisions from the 1975 and Subsequent New Vehicle Approval Procedures (75-7-7)," California Air Resources Board, April 1975.

"Staff Report - Public Hearing to Consider Fuel Evaporative Emission Regulations for Light-Duty Vehicles (75-7-6)," California Air Resources Board, April 1975.

"Staff Report - Reconsideration of Exhaust Emission Standards for 1977 and Subsequent Model-Year Heavy-Duty Engines (75-7-2)," California Air Resources Board, April 1975.

"Staff Report - Exhaust Emission Standards for 1977 Model-Year Light-Duty Vehicles (75-5-2)," California Air Resources Board, March 1975.

"Smog: A Report to the People," Caltech Environmental Quality Lab, 1972.

15. Brian Theaker (Transmission Interconnection for Alternative Sites)

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Conservation and Development Commission

In the Matter of: Application for Certification for the PUENTE POWER PROJECT	Docket No. 15-AFC-01 EXPERT DECLARATION OF BRIAN THEAKER REGARDING TRANSMISSION INTERCONNECTION FOR ALTERNATIVE SITES

I, Brian Theaker, declare as follows:

1. I am employed by NRG Energy, Inc., and am duly authorized to make this declaration.

2. I hold a Bachelor of Science Degree in Electrical Engineering from Ohio State University and a Master's Degree in Business Administration from Pepperdine University. I have over 15 years of experience with the local capacity requirements process conducted by the California Independent System Operator Corporation (CAISO). A copy of my current curriculum vitae is attached to this declaration as Attachment A. Based on my education, training and experience, I am qualified to provide expert testimony as to the matters addressed herein.

3. The Alternatives Section of the California Energy Commission Staff's Final Staff Assessment (TN #214712) ("FSA") analyzes in detail two alternative sites for development of the Puente Power Project (Project). The two alternatives sites are referred to in the FSA as the Ormond Beach Area Off-Site Alternative (FSA, p. 4.2-76) and the Del Norte/Fifth Street Off-Site Alternative (FSA, p. 4.2-46). The FSA indicates that a project

developed at the Ormond Beach Area Off-Site Alternative could be interconnected to the electrical grid at the nearest substation, which is Southern California Edison's Ormond Beach Substation (FSA, p. 4.2-77). The FSA indicates that the Del Norte/Fifth Street Off-Site Alternative could also be interconnected at the Ormond Beach Substation or to a tower along the Mandalay-Santa Clara 220-kV transmission line (FSA, p. 4.2-47).

4. In contrast to the Ormond Beach Area Off-Site Alternative, and perhaps the Del Norte/Fifth Street Off-Site Alternative if it were to be interconnected at the Ormond Beach Substation, the Project as proposed would be interconnected to the transmission grid via a single gen-tie line connecting directly to the Mandalay-Santa Clara SCE 220-kV transmission line (Applicant's Exhibit No. 1084). As explained below, this interconnection point is materially superior to that of the off-site alternatives in terms of grid reliability.

5. The CAISO has defined ten (10) local capacity areas.[1] Load-serving entities serving these local capacity areas are required to maintain minimum amounts of generation available within those local areas to ensure that the transmission system within that local area meets applicable reliability criteria established by North American Electric Reliability Corporation (NERC), the Western Electricity Coordinating Council (WECC) and the CAISO. One of those ten local capacity areas is the Big Creek/Ventura local capacity area. Ormond Beach Generating Station and Mandalay Generating Station are both located within the Big Creek/Ventura local capacity area.

6. The CAISO has defined several sub-areas within the Big Creek/Ventura local capacity area. As with the local capacity areas, load-serving entities must maintain minimum amounts of generation available within the local sub-areas to ensure the transmission system within the sub-areas also meets applicable reliability criteria. The Santa Clara sub-area and the Moorpark sub-area are two of the sub-areas within the Big Creek/Ventura local capacity area.

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[1] See, e.g., the CAISO April 29, 2016 *2017 Local Capacity Technical Analysis Final Report and Study Results* ("CAISO 2017 Local Capacity Technical Analysis"), available at https://www.caiso.com/Documents/Final2017LocalCapacityTechnicalReportApril292016.pdf. Much of the information contained in this declaration is drawn from this report.

7. Generation interconnected at Mandalay, as would be the case for Puente at the proposed site, differs from generation interconnected at Ormond Beach, as would be the case for the Ormond Beach Area Off-Site Alternative and perhaps for the Fifth Street/Del Norte Off-Site Alternative also, in the extent to which itmeets these local sub-area generation requirements. This makes the proposed Project site preferable to the alternative sites from a reliability standpoint. Generation interconnected at Ormond Beach feeds the Moorpark substation through the transmission between Ormond Beach and Moorpark. As a result, and as shown in the CAISO's report, this generation meets only the Moorpark sub-area requirements, but not the Santa Clara sub-area requirements.[2] Generation interconnected at Mandalay feeds the Santa Clara substation through the transmission connecting Mandalay Generating Station and the Santa Clara substation and meets both the Santa Clara and Moorpark sub-area generation requirements.[3]

8. Therefore, it is preferable to locate generation at Mandalay from a reliability standpoint because that generation would meet both sub-area requirements, while generation interconnected at Ormond Beach would not help meet the Santa Clara sub-area requirements.

9. Except where stated on information and belief, the facts set forth herein are true of my own personal knowledge, and the opinions set forth herein are true and correct articulations of my opinions. If called as a witness, I could and would testify competently to the facts and opinions set forth herein and in the attachments hereto.

10. I hereby sponsor this declaration into evidence in these proceedings as Applicant's Exhibit No. 1134.

---

[2] CAISO 2017 Local Capacity Technical Analysis at page 95.

[3] *Id.*

Executed on January 24, 2017, at PLACERVILLE, CALIFORNIA.

I declare under penalty of perjury of the laws of the State of California that the foregoing is true and correct.

Brian Theaker

ATTACHMENT A

Brian D. Theaker

3161 Ken Derek Lane, Placerville, California 95667

theaker@placerville.net 530-295-3305

PROFESSIONAL EXPERIENCE

NRG Energy, Inc. (2011-present)

- Director of Regulatory Affairs

Dynegy (2007-2011)

- Director of Regulatory Affairs

Williams Company (2005-2007)

- Manager of Regulatory Affairs

Responsibilities for the above positions:

- Representing my company's interests in federal and state regulatory matters through written pleadings and in-person comments
- Identifying and communicating the commercial, operational and business process impacts of regulatory matters
- Coordinating the development of company positions and advocacy on regulatory matters
- Drafting and reviewing regulatory pleadings and comments in stakeholder processes

California Independent System Operator Corporation (1997-2005)

- Director of Regulatory Affairs (2001-2005)
    - Represented the CAISO's interests in matters before the Federal Energy Regulatory Commission
- Manager of Reliability Contracts (2000-2001)
    - Supervised a group that negotiated and managed the administration of Reliability Must-Run Agreements for 15,000 MW of generating units
- Operating Engineer (1997-2000)
    - Represented the CAISO in the development and settlement of the Reliability Must-Run Agreement, which provided the CAISO with dispatch rights to generation needed to maintain the reliability of the bulk electric system and provided compensation to the owners of that generation

Los Angeles Department of Water and Power

- Electrical Engineering Associate
    - Investigated system disturbances and authored the associated reports
    - Developed computer applications for operations support, including: hydro-thermal optimization, economic dispatch, load forecasting and transmission outage tracking
    - Conducted power flow and system reliability analyses
- Electrical Engineering Assistant

Brian D. Theaker
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- Developed, supervised and reported on special tests of power system equipment

EDUCATION

- Master's Degree in Business Administration, Pepperdine University, Malibu, California
- Bachelor of Science Degree in Electrical Engineering, Ohio State University, Columbus, Ohio

PROFESSIONAL MEMBERSHIPS

- Elected Member of Western Electricity Coordinating Council Member Advisory Committee (2013-present)
- Elected Member of Western Electricity Coordinating Council Board of Directors (2008-2013)
  - Chaired Bulk Electric System Definition Task Force, Regional Criteria Working Group, Data Sharing Task Force; served as Vice-Chair of Reliability Policy Issues Committee
- Registered California Professional Engineer (California 12612)

16. Brian Theaker and Sean Beatty

(Response to Opening Testimony of CBD Witness Bill Powers and Opening Testimony of City of Oxnard Witness Jim Caldwell)

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State of California

Energy Resources

Conservation and Development Commission

In the Matter of: Application for Certification for the PUENTE POWER PROJECT	Docket No. 15-AFC-01 JOINT EXPERT DECLARATION OF BRIAN THEAKER AND SEAN BEATTY IN RESPONSE TO OPENING TESTIMONY OF CBD WITNESS BILL POWERS AND OPENING TESTIMONY OF CITY OF OXNARD WITNESS JIM CALDWELL

I, Brian Theaker, declare as follows:

1. I am employed by NRG Energy, Inc., and am duly authorized to make this declaration.

2. I hold a Bachelor of Science Degree in Electrical Engineering from Ohio State University and a Master's Degree in Business Administration from Pepperdine University. I have over 15 years of experience with the local capacity requirements process conducted by the California Independent System Operator Corporation (CAISO). A copy of my current curriculum vitae is attached to this declaration as Attachment A. Based on my education, training and experience, I am qualified to provide expert testimony as to the matters addressed herein.

3. I have reviewed the Opening Testimony of Bill Powers filed by Intervenor Center for Biological Diversity (CBD) (CBD Exhibit No. 7000) ("Powers Testimony") (CEC TN# 215440-1). I have reviewed the Opening Testimony of Jim Caldwell filed by Intervenor Center for the City of Oxnard ("Caldwell Testimony") (CEC TN# 215439). Without waiving any

rights that Applicant has to raise appropriate objections to the Powers Testimony or Caldwell Testimony during evidentiary hearings, I hereby respond, together with Sean Beatty, to certain of the arguments raised therein.

4. By this declaration, I provide a summary of the California Public Utilities Commission (CPUC) approval of the contract for the Project as requested by Southern California Edison (SCE), which is directly relevant to my response to the Powers Testimony and Caldwell Testimony as it pertains to the need for the Project (i.e., whether the No Project Alternative is feasible) and whether such need could be met with alternative technologies in lieu of the Project. I have reviewed and am generally familiar with the analysis and conclusions in the materials cited herein.

CPUC Approval of the Project Contract

5. The need for the Project has been established by the CPUC in CPUC Decision (D.)16-05-050, *Decision Approving, in Part, Results of Southern California Edison Company Local Capacity Requirements Request for Offers for Moorpark Sub-Area Pursuant to Decision 13-02-015* (June 1, 2016), attached hereto as Exhibit A. D.16-05-050 culminated a multi-year planning process by the CPUC that included extensive involvement from multiple agencies, stakeholders and the public, where this careful planning process resulted in two very detailed, substantive decisions that established a clear framework and rigorous procedural requirements for SCE to follow when procuring generation within the Los Angeles basin and Moorpark areas to meet reliability needs: CPUC D.13-02-015, *Decision Authorizing Long-Term Procurement for Local Capacity Requirements* (Feb. 13, 2013) (LTPP Track 1 Decision), and D.14-03-004, *Decision Authorizing Long-Term Procurement for Local Capacity Requirements Due to Permanent Retirement of the San Onofre Nuclear Generation Stations* (Mar. 14, 2014) (LTPP Track 4 Decision), attached hereto as Exhibits B and C, respectively.

6. In the LTPP Track 1 Decision, the CPUC determined that "SCE should be required to procure a minimum of 215 MW and a maximum of 290 MW in the Moorpark sub-

area of the Big Creek/Ventura local reliability area."[1] The LTPP process set the course for SCE to procure substantial "preferred resources," which generally include renewable generation, energy efficiency, demand response, and energy storage, within the Los Angeles basin and Moorpark areas. Nonetheless, the CPUC recognized that "[i]t is necessary that a significant amount of this procurement level be met through conventional gas fired resources in order to ensure [local capacity requirement] needs will be met."[2]

7. With the CPUC's directive from the LTPP, SCE initiated a detailed request for offers (RFO) process to identify resources within the Moorpark area to meet the identified need. SCE's RFO was obligated to comply with a number of requirements established by the LTPP Decisions, and SCE's procurement plan was approved by the CPUC staff. The approved procurement plan specified how SCE would consider various factors required by D.13-02-015, including reliability factors such as: least-cost/best-fit analysis, consultation with the CAISO, energy and ancillary services benefits, permitting and interconnection, resource adequacy capacity benefits, and local effectiveness factors.[3]

8. In the RFO, SCE solicited and received bids from various resource types.[4] SCE received over 200 offers from 30 bidders, including bids from various resource categories.[5] SCE selected all preferred resource bids that were included in the final offers for the Moorpark

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1 D.13-02-015, at 128, Conclusion of Law 11.

2 D.13-02-015, at 123, Finding of Fact 30.

3 D.16-05-050, at 9.

4 Response of NRG Energy Center Oxnard LLC and NRG California South LP to Applications for Rehearing of Decision 16-05-050, 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, Application 14-11-016 (July 18, 2016), attached as Exhibit D ("NRG Response to Applications for Rehearing"), 27; Southern California Edison Company's (U 338-E) Response to Application for Rehearing of Decision 16-05-050 (Public Version), 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, Application 14-11-016 (July 18, 2016), attached hereto as Exhibit E ("SCE Response to Applications for Rehearing"), 20; D.16-05-050, at 36, Findings of Fact 6, 11.

5 SCE Response to Applications for Rehearing, 20; D.16-05-050, at 24, 36, Findings of Fact 6, 11.

sub-area, with the exception of some in-front-of-meter energy storage.[6] Even after accepting the preferred resources bids, SCE still needed gas-fired generation to meet the minimum local capacity requirements.[7]

9. Following the RFO process, SCE's selected contracts, including the Project contract, required approval from the CPUC to ensure compliance with the LTPP Decisions. In D.16-05-050, the CPUC approved the Project contract, finding the "Project is necessary to meet the identified local reliability need in the Moorpark sub-area." [8] The CPUC emphasized the reliability benefits derived from the Project's operational characteristics:

> Our review of the reliability risks facing the NRG Puente Project reflects our obligation to ensure investments in electricity infrastructure are used and useful and contribute to local reliability.[9]
>
> …
>
> According to undisputed evidence from NRG, Puente will be a reliable peaker plant with fast-start, fast ramping capabilities which provide important grid support services.[10]

The CPUC found that the Project, along with the other procured resources, "will enhance the reliable operation of SCE's electrical service and support the reliability of service starting in 2021."[11] Specifically pertaining to the Project, the CPUC determined:

> If the Puente Project is delayed or rejected, the CAISO is concerned that it will increase the possibility that there will be insufficient resources to meet local capacity requirements when generation facilities in the Moorpark sub-area retire at the end of

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[6] NRG Response to Applications for Rehearing, 28-29; SCE Response to Applications for Rehearing, 20-21.

[7] NRG Response to Applications for Rehearing, 29.

[8] D.16-05-050, at 36, Finding of Fact 13.

[9] D.16-05-050, at 8-9.

[10] D.16-05-050, at 9-10 ("Puente has operational characteristics that are similar to (and better than) the retiring OTC units. Puente will utilize a new GE 7HA.01 combustion turbine. This technology has been manufactured and used in the power generation industry for many years, and is a proven and reliable technology. The combustion turbine is designed to start quickly, ramp up and down, and turn off when not needed. The combustion turbine can start and be at its full capacity in 10 minutes. Puente will be able to ramp up and down at a rate of approximately 40 MW per minute. Puente will have a flexible operating range between 81 MW (equivalent to 30 percent of maximum load) and 270 MW at standard conditions.").

[11] D.16-05-050, at 23.

> 2020. We agree with the CAISO that the Puente Project is necessary to meet the identified local reliability need in the Moorpark sub-area. The need determination of the Moorpark sub-area in D.13-02-015 depended upon the retirement of Mandalay Units 1 and 2 and Ormond Beach once-through-cooling generation units.[12]

10. The CAISO submitted testimony to the CPUC, concluding "the results of SCE's 2013 Moorpark RFO are consistent with the CAISO's planning assumptions in the 2014-2015 transmission plan. The resources selected in the RFO meet the minimum procurement requirements set forth in the Commission's Track 1 long-term procurement plan decisions, and they are effective and necessary to meet long-term reliability needs as demonstrated by the CAISO's analyses."[13] Thus, the "resources selected in SCE's 2013 RFO will enhance the reliability of SCE's electrical service starting in 2021 time frame. However, . . . the resources for which SCE requests approval in this proceeding are only a portion of those necessary to meet reliability needs in the Moorpark sub-area."[14]

11. Following D.16-05-050, applications for rehearing were filed by the City of Oxnard, Sierra Club and California Environmental Justice Association (jointly), and the

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[12] D.16-05-050, at 25.

[13] Testimony of Robert Sparks on Behalf of the California Independent System Operator Corporation, 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, Application 14-11-016, attached hereto as Exhibit F ("Sparks Testimony"), at 4:7-12; Testimony of Neil Millar on Behalf of the California Independent System Operator Corporation, 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, Application 14-11-016, attached hereto as Exhibit G, at 4:21-26 ("The CAISO has analyzed the results of SCE's RFO in the context of the 2014-2015 transmission plan which was presented to the CAISO Board of Governors and approved on March 26. These results indicate that the proposed RFO procurement can meet long-term local capacity requirement needs when combined with the California Energy Commission's forecast of 87 MW of additional achievable energy efficiency for the Moorpark subarea.").

[14] Sparks Testimony, at 3:21 to 4:4; *see also id.*, at 3:7-13 ("The CAISO identified the most critical contingency in the Moorpark sub-area as the loss of the Moorpark-Pardee 230 kV #3 line followed by the loss of the Moorpark-Pardee 230 kV #1 and #2 lines, which would cause voltage collapse. The local capacity requirement analysis conducted in the 2014-2015 transmission plan indicates that the selected RFO resources meet this identified reliability constraint and are sufficient to meet the local reliability needs in the Moorpark sub-area through 2024, based on the assumptions in the transmission plan.").

Center for Biological Diversity (CBD).[15] In D.16-12-030, *Order Modifying Decision (D.) 16-05-050 and Denying Rehearing, as Modified* (Dec. 5, 2016), attached hereto as Exhibit H, the CPUC denied the applications for rehearing and reaffirmed its prior approval.

The No Project Alternative and Alternative Technology Alternatives

No Project Alternative

12. The Powers Testimony and Caldwell Testimony make various statements that the Project is not needed. For example, Mr. Powers states that the 2009 Integrated Energy Policy Report, on which the CPUC relied in D.13-02-015 to determine the local capacity requirement authorization for the Big Creek/Ventura local capacity area, is outdated.[16] Mr. Powers states that the report forecasts peak demand to be approximately 700 MW greater than two peak demand forecasts from 2016, and based on such demand, the Project is no longer necessary.[17] Mr. Caldwell states that the CPUC overestimated the need for procurement because the only need for the Project relates to systemwide reliability, not a local reliability need.[18] Mr. Caldwell states that because systemwide resources can resolve systemwide concerns, the Project is not needed.[19] Mr. Caldwell estimates that the actual need is only 89-92 MW, not the full amount identified by the CPUC in the LTPP, thereby eliminating the need for the Project.[20]

13. As detailed herein, evidence supports a determination that the Project is necessary to meet reliability needs in the Moorpark area, and therefore, the reliability needs would not be met under the No Project Alternative.[21] In the application for rehearing discussed above, CBD also argued that the Project is not needed. The CPUC rejected arguments that the

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15 The CPUC rejected the City of Oxnard's application for rehearing of D.16-05-050 because the application failed to meet the requirements of California Public Utilities Code § 1732 for a permissible application. D.16-12-030, at 3-4.

16 Powers Testimony, at 2-3.

17 Powers Testimony, at 2-3.

18 Caldwell Testimony, at 2-3.

19 Caldwell Testimony, at 3.

20 Caldwell Testimony, at 4.

21 Sparks Testimony, at 3:21 – 4:4 (stating that reliability risks would not be fully addressed even by the Project).

Project is not needed as flawed and untimely given the established procedural framework for identifying the need for new procurement such as the Project. The CPUC explained:

> The Commission's process flows from the goals of [California Public Utilities Code] section 454.5 to ensure safe and reliable electric service as well as reasonable service for customers at just and reasonable rates. Based on these objectives, the Commission has developed a two-step [LTPP] process.
>
> In step one, we render a "needs determination" to identify what new system-wide and or local capacity generation should be obtained. Utilities then solicit bids to fill the energy need via an RFO or bilateral contract, monitored by an Independent Evaluator to ensure a fair and reasonable process is used.
>
> In step two, generally a separate proceeding, we evaluate a utility's application for approval of procurement contracts that resulted from the RFO. At this juncture, capacity need is no longer an issue. That has already been determined by a decision such as the Track 1 Decision.[22]

14. In the application for rehearing, CBD also argued that, notwithstanding the foregoing, changed circumstances required a reconsideration of the Project's need. Mr. Powers and Mr. Caldwell make similar statements.[23] The CPUC declined CBD's request on two grounds. First, that "in the interest of a timely and orderly procurement process, we rarely revisit need at this juncture in the procurement process."[24] Second, the CPUC reaffirmed the soundness of the technical evidence supporting the need determination.[25]

Alternative Technologies

15. Mr. Powers and Mr. Caldwell indicate that alternative technologies could satisfy the need being met by the Project. For example, Mr. Powers states that both battery storage and demand response are feasible and cost-effective alternatives to the Project, that energy storage is available in sufficient quantities to meet local capacity requirements, that SCE has recognized energy storage as providing superior cost-effectiveness compared to simple cycle

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22 D.16-12-030, at 25-26.

23 Caldwell Testimony, at 2-4; Powers Testimony, at 2-3.

24 D.16-12-030, at 26.

25 D.16-12-030, at 27.

gas turbines, and that energy storage can be deployed quickly.[26] Mr. Powers concludes that, contrary to the Final Staff Assessment, demand response is also available in sufficient quantities.[27] Mr. Caldwell states that it is likely that the need in the Moorpark subarea (which he states amounts to 89-92 MW of actual local requirements capacity need) can be met solely with preferred resources, pointing to energy storage as a possible resource and to the 124.9 MW of preferred resources that SCE procured in an area with less peak demand than the Moorpark subarea.[28] Mr. Caldwell states that a one-year process to procure those resources is feasible, including a special CAISO study to define precisely which resources are acceptable to meet that need, followed by an RFO conducted by SCE.[29]

16. This testimony is inconsistent with evidence that alternative technologies would not feasibly and cost-effectively displace the need for the Project. As a general matter, the LTPP Decisions recognize uncertainties associated with procuring preferred resources and energy storage. In D.14-03-004, the CPUC concluded that 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."[30] D.14-03-004, Conclusion of Law 38 emphasizes that "a prudent approach to reliability entails a gradual increase in the level of preferred resources and energy storage into the resource mix." Further, "[w]hile we see considerable value in pursuing the experiment to procure energy storage resources, we do not intend that SCE be required to sign contracts from energy storage suppliers at all costs."[31]

17. Moreover, California's "loading order" establishes "that the state, in meeting its energy needs, would invest first in energy efficiency and demand-side resources,

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[26] Powers Testimony, at 15-18.

[27] Powers Testimony, at 18-19.

[28] Caldwell Testimony, at 9-10.

[29] Caldwell Testimony, at 9, 11.

[30] D.14-03-004, at 61.

[31] D.13-02-15, at 88-89.

followed by renewable resources, and only then in clean conventional electricity supply."[32] In the LTPP Track 4 decision, the CPUC clarified its obligation to balance the loading order with reliability needs:

> 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. . . . Instead of procuring a fixed amount of preferred resources and then procuring fossil-fuel resources, the IOUs are required to continue to procure the preferred resources "to the extent that they are feasibly available and cost effective."[33]

18. Specifically for the Project, the CPUC, in D.16-12-03, considered and squarely rejected arguments that preferred resources could cost-effectively replace the need for the Project:

> The evidence showed there were insufficient cost-effective preferred resource bids in the Moorpark sub-area to meet the identified need. Therefore, the Puente Project contract is necessary to meet the identified local reliability need in the Moorpark sub-area.[34]

19. The CPUC explained, "the Independent Evaluator Report confirms that SCE included preferred resources in its evaluation process, and conducted fairly substantial outreach to solicit all resource types. Despite that, SCE received nowhere near enough cost-effective preferred resource final offers to meet the minimum required capacity need. It accepted all cost-effective offers, but then had to meet remaining need with gas-fired resources."[35] Indeed, the "record showed there were fewer overall offers in the Moorpark sub-area, and SCE accepted all cost-effective preferred resources that were offered. That was still far short of the

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[32] D.12-01-033, at 17 (quoting Energy Action Plan 2008 Update, at 1).

[33] D.14-03-004, at 13-15.

[34] D.16-12-030, at 30, Ordering Paragraph 1.e (modifying Finding of Fact 13 in D.16-05-050); *see also id*., at 5-6 ("Overall, the contract's economics and general terms and conditions were found to represent the best resource available from the RFO, and the energy is needed to meet local reliability needs in Moorpark given pending retirement of Mandalay Units 1 and 2, and the Ormond Beach once-through cooling ('OTC') generation units.").

[35] D.16-12-030, at 17-18.

identified need."[36] Accordingly, the CPUC reached the following conclusion about the lack of availability of preferred resources and the need for the Project:

> Because there were insufficient cost-effective preferred resource offers to meet the identified need in the Moorpark sub-area, selection of the Puente Project contract is reasonable and complies with the requirements set out in D.13-02-015.[37]

20. Except where stated on information and belief, the facts set forth herein are true of my own personal knowledge, and the opinions set forth herein are true and correct articulations of my opinions. If called as a witness, I could and would testify competently to the facts and opinions set forth herein and in the attachments hereto.

21. I hereby sponsor this declaration into evidence in these proceedings as Applicant's Exhibit No. 1131.

Executed on January 24, 2017, at PLACERVILLE, CALIFORNIA

I declare under penalty of perjury of the laws of the State of California that the foregoing is true and correct.

Brian Theaker

---

[36] D.16-12-030, at 19.

[37] D.16-12-030, at 30, Ordering Paragraph 1.f (modifying Conclusion of Law 6 in D.16-05-050).

ATTACHMENT A

Brian D. Theaker

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PROFESSIONAL EXPERIENCE

NRG Energy, Inc. (2011-present)

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- Developed, supervised and reported on special tests of power system equipment

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- Elected Member of Western Electricity Coordinating Council Board of Directors (2008-2013)
  - Chaired Bulk Electric System Definition Task Force, Regional Criteria Working Group, Data Sharing Task Force; served as Vice-Chair of Reliability Policy Issues Committee
- Registered California Professional Engineer (California 12612)

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Attorneys for Applicant

State of California

Energy Resources

Conservation and Development Commission

In the Matter of: Application for Certification for the PUENTE POWER PROJECT	Docket No. 15-AFC-01 JOINT EXPERT DECLARATION OF BRIAN THEAKER AND SEAN BEATTY IN RESPONSE TO OPENING TESTIMONY OF CBD WITNESS BILL POWERS AND OPENING TESTIMONY OF CITY OF OXNARD WITNESS JIM CALDWELL

I, Sean Beatty, declare as follows:

1. I am employed by NRG Energy, Inc., and am duly authorized to make this declaration.

2. I hold a Bachelor of Arts Degree from the University of California, Berkeley and a Juris Doctor Degree from the University of California, Hastings College of the Law. I have over 15 years of experience practicing before California energy regulatory agencies, including the California Public Utilities Commission and the California Energy Resources Conservation and Development Commission. A copy of my current curriculum vitae is attached to this declaration as Attachment A. Based on my education, training and experience, I am qualified to provide expert testimony as to the matters addressed herein.

3. I have reviewed the Opening Testimony of Bill Powers filed by Intervenor Center for Biological Diversity (CBD) (CBD Exhibit No. 7000) ("Powers Testimony") (CEC TN# 215440-1). I have reviewed the Opening Testimony of Jim Caldwell filed by Intervenor Center for the City of Oxnard ("Caldwell Testimony") (CEC TN# 215439).

4. By this declaration, I join in sponsoring Applicant's Exhibit No. 1131, which I prepared jointly with Brian Theaker, and which is incorporated herein by reference.

5. Except where stated on information and belief, the facts set forth herein are true of my own personal knowledge, and the opinions set forth herein are true and correct articulations of my opinions. If called as a witness, I could and would testify competently to the facts and opinions set forth herein and in the attachments hereto.

Executed on January 24, 2017, at San Francisco.

I declare under penalty of perjury of the laws of the State of California that the foregoing is true and correct.

S. P. Beatty

Sean Beatty

ATTACHMENT A

Sean P. Beatty
Regional General Counsel – West
NRG Energy, Inc.

Member
State Bar of California
Washington, DC Bar

Education
University of California, Hastings College of the Law
Juris Doctor, 1991
Class Rank: Top 27%

University of California, Berkeley
Bachelor of Arts, Philosophy, 1988

Experience
NRG Energy, Inc., San Francisco, CA
Regional General Counsel – West, August 2013 to Present
•Negotiate commercial agreements on behalf of project development and operating entities.
•Advise on loan compliance matters
•Manage outside counsel

NRG Energy, Inc., Pittsburg, CA
(Predecessors: GenOn Energy, Inc., Dec. 2010-Dec. 2012, Mirant, Aug. 2008-Dec. 2010)
Director, Regulatory Affairs, December 2012 to August 2013
Director, West Regulatory Affairs & Associate General Counsel, December 2010 to December 2012
Director, State Regulatory Affairs, April 2010 to December 2010
Sr. Manager, Regulatory Affairs, August 2008 to April 2010
•Formulated and advocated policy positions related to energy and climate change issues.
•Represented company before the CPUC, CEC, CAISO and other state agencies.
•Represented company in trade associations, including WPTF, IEP and CCEEB.

Cooper, White & Cooper LLP, San Francisco, CA
Partner January 1, 2000 to August 2008
Associate July 1995 to January 1, 2000
•Represented telecommunications carriers in rulemaking and arbitration proceedings before the CPUC.
•Negotiated commercial agreements on behalf of clients.
•Litigated commercial disputes in federal and state courts.
•Advised clients regarding compliance with privacy law requirements.
•Represented cable television companies and telecommunications carriers on franchise and encroachment issues before local jurisdictions.
•Participated in industry legislative committee to formulate strategies relative to California legislation.

Law Offices of Richard S. Myers, Washington, DC
Associate January 1993 to May 1995
•Represented wireless clients in rulemaking and licensing proceedings before the Federal Communications Commission.
•Worked on transactional matters for wireless clients including loan and partnership agreements.

U.S. Magistrate Judge Phyllis Hamilton (N.D. Cal.), San Francisco, CA
Law Clerk August 1991 to September 1992
•Briefed Judge Hamilton on legal issues presented to her court.
•Wrote initial drafts of summary judgment and discovery orders.

EXHIBIT A

Decision 16-05-050 May 26, 2016

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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.	Application 14-11-016 (Filed November 26, 2014)

DECISION APPROVING, IN PART, RESULTS OF SOUTHERN CALIFORNIA EDISON COMPANY LOCAL CAPACITY REQUIREMENTS REQUEST FOR OFFERS FOR MOORPARK SUB-AREA PURSUANT TO DECISION 13-02-015

Tale of Contents

Title **Page**

DECISION APPROVING, IN PART, RESULTS OF SOUTHERN CALIFORNIA EDISON COMPANY LOCAL CAPACITY REQUIREMENTS REQUEST FOR OFFERS FOR MOORPARK SUB-AREA PURSUANT TO DECISION 13-02-015

Summary

We approve of the results of the request for offers (RFO) conducted by Southern California Edison Company (SCE) pursuant to the Commission's directives in Decision (D.) 13-02-015 issued in Rulemaking 12-03-014,[1] with certain exceptions. We approve SCE's contract with NRG for the Puente Project today. The Puente Project is a 262 megawatt (MW) natural gas-fired peaker facility. The California Energy Commission must also review the project under its CEQA-equivalent process regarding potential sea level rise and environmental justice matters, as well as all other matters under its jurisdiction.

We also approve several preferred resource load reduction contracts with energy efficiency and solar generation projects totaling approximately 12 MW. Between the Puente Project and the 12 MW of preferred resources, SCE has satisfied its obligation pursuant to D.13-02-015 to procure between 215 and 290 MW in the Moorpark sub-area for local reliability purposes.

Additionally, we will consider the Ellwood contract (and an associated 0.5 MW energy storage project), in a separate decision along with consideration of any additional reliability need in the Goleta area. This application remains open for this purpose.

1. Procedural Background

D.13-02-015, issued on February 13, 2013, ordered SCE to procure, via a Request for Offers (RFO), a minimum of 215 megawatts (MW) and a maximum

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

of 290 MW of electrical capacity in the Moorpark sub-area of the Big Creek/Ventura local reliability area (Moorpark sub-area) to meet identified long-term local capacity requirements (LCR) by 2021.[2] The Commission found this LCR need existed, in large part, due to the expected retirement of the Ormond Beach and Mandalay once-through-cooling (OTC) generation facilities, which are both located in Oxnard, California. These facilities currently have approximately 2,000 MW of capacity.

For projects to be considered for this particular RFO, the projects had to meet certain minimum characteristics, including that the projects be incremental, i.e., new capacity.[3] Other minimum requirements included that the projects qualify as Full Capacity Deliverability Status and delivery had to include the entire calendar year 2021.[4] These minimum characteristics were established in D.13-02-015. This decision did not specify that SCE procure any specific resources types.

The Commission in D.13-02-015 ordered SCE to submit an LCR procurement plan to the Energy Division explaining how SCE would conduct this RFO.[5] SCE submitted its initial LCR procurement plan on July 15, 2013. Energy Division approved a modified version of SCE's plan on September 4, 2013.[6] SCE launched its LCR RFO on September 12, 2013.[7]

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[2] D.13-02-015 at 131 (OP 2).

[3] Ex. SCE-1 at 14.

[4] Ex. SCE-1 at 14.

[5] D.13-02-015 at 133-134 (OPs 5-7).

[6] SCE July 22, 2015 Opening Brief at 3.

[7] Ex. SCE-1 at 4; SCE July 22, 2015 Opening Brief at 3.

On November 26, 2014, SCE filed this Application for approval of the results of its 2013 LCR RFO for the Moorpark sub-area seeking approval of 11 contracts.[8] The Application also seeks approval of one project (the Ellwood refurbishment) that did not bid into the RFO.

A brief review of the 11 contracts follows: One of the contracts is a 20-year contract for gas-fired generation (totaling 262 MW of capacity). This contract is a resource adequacy (RA) purchase agreement with NRG Energy Center Oxnard, LLC (NRG) for a new simple cycle peaking facility known as the Puente Power Project (NRG Puente Project).[9]

Another contract, which is also for gas-fired generation (totaling 54 MW of capacity), does not count toward SCE's incremental procurement requirements for the Moorpark sub-area under D.13-02-015. This contract is a 10-year agreement with NRG California South, LP (NRG California South) for the existing 54 MW Ellwood Generating Station (Ellwood), which NRG California South will refurbish (without any change in size or capacity) to provide a remaining 30-year design life.[10] Ellwood was included as an existing resource in the CAISO study that served as the foundation of D.13-02-015 and, in that study, it was assumed to continue operating in the need assessment. Therefore, the Ellwood contract is not an incremental resource and does not count toward SCE's procurement requirements for the Moorpark sub-area.[11]

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[8] D.13-02-015 at 68, 131 (OP 2).

[9] Ex. SCE-1 at 55; Ex. NRG-1 at 2.

[10] Ex. SCE-1 at 57.

[11] Ex. SCE-1 at 3, fn. 1; Ex. SCE-1 at 57.

SCE also seeks approval of an energy storage contract with NRG California South (NRG Energy Storage contracts). This project would be located on the site of Ellwood. The NRG Energy Storage contract is a tolling agreement for a 0.5 MW storage facility.[12]

The remaining contracts include six contracts for energy efficiency (totaling 6 MW of capacity) and two contracts for renewable distributed generation (totaling 5.66 MW of capacity).[13]

A summary of the selected offers is provided in the table below.[14]

Produce Category	**Counterparty**	**Total Contracts**	**Max Quantity (LCR MW)**
Gas-Fired Gen – Incremental	NRG Energy Center Oxnard LLC (Puente Project)	1	262
Gas-Fired Gen – Not Incremental	NRG California South LP (Ellwood Project)	1	0 (or 54 – not incremental)
Energy Efficiency - Incremental	Onsite Energy Corporation	6	6
Renewable Distributed Gen - Incremental	Solar Star California XXXIV, LLC Solar Star California XXXIX, LLC	2	5.66
Energy Storage (In Front Of Meter) – Incremental	NRG California South LP	1	.5

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[12] Exhibit SCE-1 at 54, lines 12-17; NRG August 5, 2015 reply brief at 7.

[13] Exhibit SCE-1 at 3, Table I-1.

[14] Exhibit SCE-1 at 3 and 55.

On January 12, 2015, City of Oxnard, World Business Academy (WBA), the Office of Ratepayer Advocates (ORA), and the Sierra Club, Center for Biological Diversity (CBD) filed protests. Other parties filed responses to this Application, including NRG, NRG California South, California Energy Storage Alliance (CESA), EnerNOC, Inc. (EnerNOC), the Western Power Trading Forum, and Alliance for Retail Energy Markets (AReM) with the Direct Access Customer Coalition (DACC).

Parties submitted prepared testimony in preparation for evidentiary hearings which were held on May 27, 28, and 29, 2015.

A public participating hearing (PPH) was held in Oxnard on July 15, 2015. The general public and public representatives presented opinions at the PPH in Oxnard that were mostly against the Ellwood project and NRG Puente Project.[15] Some speakers supported the projects. These public comments are part of the administrative record of this proceeding, although not the evidentiary record. In addition, hundreds of letters from the public have been included in the correspondence file of this proceeding.

Parties filed concurrent opening briefs and reply briefs on July 22, 2015 and August 5, 2015, respectively.

1.1. Standard of Review

We review today's Application and request therein under a reasonableness standard. The question is whether SCE conducted its RFO in a reasonable manner, consistent with the law and Commission decisions, and whether the results are reasonable.

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15 The reporter's transcript of this public participation meeting can be found in Central Files at the Commission.

1.2. Burden of Proof

The burden of proof is on the Applicant in this proceeding to support its request by a preponderance of evidence. In short, the preponderance of evidence burden of proof standard is met if the proposition is more likely to be true than not true. The standard is also described as being met by the evidence presented when the proposition is more probable than not.

2. Scope of Issues

The issues to be determined are:[16]

1. Whether the results of SCE's 2013 LCR RFO for the Moorpark sub-area enhance the safe and reliable operation of SCE's electrical service?
2. Does the Application comply with the procurement authority granted by the Commission in D.13-02-015?
3. Are the results of SCE's 2013 LCR RFO for the Moorpark sub-area a reasonable means to meet the 215 to 290 MW of identified LCR need determined by D.13-02 015? This issue includes consideration of the reasonableness of at least the following:
    a. Are the price, terms and conditions of the LCR contracts reasonable?
    b. Did SCE's RFO process limit certain resource bids from being considered? If so, were these limitations reasonable?
    c. Was the process used to develop the eligibility requirements reasonable?
    d. Did the process and outcome of any consultations between the California Independent System Operator

[16] March 13, 2015, *Assigned Commissioner's Ruling and Scoping Memo* at 4-5.

and SCE impact resources requirements and contract selection? If so, was this impact reasonable?

e. Are the LCR RFO contracts consistent with the Commission's Emissions Performance Standards?

4. Should the Commission approve these contracts prior to completion and a final decision by the California Energy Commission (CEC) of the California Environmental Quality Act (CEQA) review? The CEC is the lead agency for purposes of the CEQA review. As a result, environmental matters will largely be resolved by the CEC.
5. Is SCE's proposed rate treatment, cost recovery, and cost allocation just and reasonable? (A workshop for the purpose of clarifying SCE's proposed Cost Allocation Mechanism, or CAM, treatment will not be necessary.)
6. Is the 54 MW Ellwood Refurbishment project appropriate for the Commission to consider in this proceeding and, if so, is the contract reasonable?
7. Is the contract with NRG California South LP, for a 0.5 MW storage project, reasonable?

3. 262 MW Gas-Fired Generation NRG Puente Project - Offer 447019

This decision approves the NRG Puente Project contract.

3.1. Grid Reliability - Flooding

SCE seeks Commission approval of a 20-year contract with NRG Energy Center Oxnard LLC for 262 MW of gas-fired generation from a new GE 7HA.01 gas-fired CT with a contract start date of June 1, 2020 to be located at 393 North Harbor Boulevard, Oxnard, California.[17]

Our review of the reliability risks facing the NRG Puente Project reflects our obligation to ensure investments in electricity infrastructure are used and

[17] Ex. SCE–1 at 55.

useful and contribute to local reliability. The Commission's review of reliability risks is distinct from the CEC's environmental review but, nevertheless, includes some of the same evidence.

The reliability of the grid is one aspect of the Commission's broader analysis and responsibility to ensure safety under Pub. Util. Code § 451,[18] consistent with Section 454.5.[19] Section 454.5 concerns utility procurement plans. Pursuant to D.13-02-015, SCE's procurement plan for the Moorpark sub-area was approved by the Energy Division after modifications.[20] The approved procurement plan specified how SCE would consider various factors required by D.13-02-015, including reliability factors such as:

least-cost/best-fit analysis, consultation with the CAISO, energy and ancillary services benefits, permitting and interconnection, resource adequacy capacity benefits, and local effectiveness factors.

According to undisputed evidence from NRG, Puente will be a reliable peaker plant with fast-start, fast ramping capabilities which provide important grid support services. Puente has operational characteristics that are similar to (and better than) the retiring OTC units. Puente will utilize a new GE 7HA.01 combustion turbine. This technology has been manufactured and used in the

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[18] Section 451 provides, in relevant part, "Every public utility shall furnish and maintain such adequate, efficient, just, and reasonable service, instrumentalities, equipment, and facilities … as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public."

[19] We do not here determine whether there is an obligation for the Commission to evaluate reliability issues in review of procurement contracts that is separate from the Commission's obligations under Section 454.5.

[20] The SCE procurement plan also addressed SCE's plans for the West Los Angeles Basin, per D.13-02-015.

power generation industry for many years, and is a proven and reliable technology. The combustion turbine is designed to start quickly, ramp up and down, and turn off when not needed. The combustion turbine can start and be at its full capacity in 10 minutes. Puente will be able to ramp up and down at a rate of approximately 40 MW per minute. Puente will have a flexible operating range between 81 MW (equivalent to 30 percent of maximum load) and 270 MW at standard conditions.

An additional issue raised in this proceeding is the risk of flooding and sea rise. SCE's procurement plan does not specifically address the risk of flooding on reliability. However, the record in this proceeding raises the question of whether sea level rise and potential flooding would be reliability risks for the Puente Project. The CEC evaluates the risk of flooding from an environmental perspective; however, this Commission reviews this risk from a reliability perspective.

Parties presented competing points of view on the risks posed to reliability and safety based on the location of the plant, as the proposed beach location is near sea level. According to the Sierra Club and City of Oxnard, local reliability could be compromised with a future sea level rise.[21] Dr. David Revell, expert witness of the City of Oxnard, states "portions of the Generating Station's site are exposed to coastal flooding hazards under existing conditions" and the flood risk will only increase as sea level rises.[22] According to the City of Oxnard's expert witness, Dr. Revell, since the site is directly adjacent to the Pacific Ocean, on the

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[21] Oxnard July 22, 2015 Opening Brief at 6-7 and Exhibit A; Ex. CO-1 at 2; Sierra Club July 22, 2015 Opening Brief at 2-4.

[22] Ex. CO-1 at 2; Oxnard July 22, 2015 Opening Brief at 5-7; Sierra Club July 22, 2015 Opening Brief at 2-3.

beach, it will be exposed to coastal hazards by 2030 and the entire site will likely be flooded by 2060, according to the most conservative sea level rise projections.[23]

Further, the City of Oxnard's expert stated that much of the sandy beach protecting the site is the result of the dredging of Ventura Harbor. Since future funding for this dredging is in doubt, the coastal hazard risk for the NRG Puente Project may increase substantially.[24] The City of Oxnard's second expert, David Cannon, P.E., testified that there would be significant tsunami risk under current conditions, and the risk will increase as sea levels rise.[25] The City of Oxnard noted that in the event of an earthquake-tsunami scenario, the Goleta-Santa Clara 230 kV transmission line could be taken out by the earthquake and Puente would be knocked out of service by the earthquake-induced tsunami.[26]

The City of Oxnard and Sierra Club emphasized that this is a reliability issue, squarely within the jurisdiction of the Commission, since it concerns not the effects of the project on the environment, but the effects of the environment on the reliability of the project.[27]

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[23] Oxnard July 22, 2015 Opening Brief at 7.

[24] Oxnard July 22, 2015 Opening Brief at 7; Sierra Club July 22, 2015 Opening Brief at 3.

[25] Oxnard July 22, 2015 Opening Brief at 10-11.

[26] Sierra Club July 22, 2015 Opening Brief at 4, Oxnard July 22, 2015 Opening Brief at 11-13.

[27] Sierra Club July 22, 2015 Opening Brief at 4; Oxnard August 5, 2015 Reply Brief at 15-21. SCE, however, argues that the climate-related issues (such as tsunami impacts, floods, and sea levels) are, in fact, environmental issues and as such, they will be addressed by the CEC in its review of the proposed project. SCE July 22, 2015 Opening Brief at 7.

On the other hand, NRG states that no such risks exist, as determined by its own expert analysis by Mr. Mineart.[28] NRG further argued that, even if risks existed, the CEC has jurisdiction. NRG states that, to date, the existing facility, Mandalay, at the NRG Puente Project site, has not flooded as a result of large storms and that the beach area surrounding the site has only grown wider in the last approximately 30 years.[29] Mr. Mineart provided evidence that the NRG Puente Project is not at risk for coastal hazards or tsunamis and highlights flaws in the opponents' experts' testimony.[30]

NRG further notes that, even if merit exists to Sierra Club's and City of Oxnard's claims of potential flooding and reliability risks, that the Commission should approve of the contract because the financial risk of destruction is not carried by SCE because, if the NRG Puente Project is destroyed by a tsunami or flood, SCE is only responsible for capacity payments and could terminate the contract if the project does not provide power.[31]

Based on a review of all of the expert testimony, we find that, during the term of the contract and the expected life of the plant, the risk of coastal flooding has not been shown to compromise the reliability of the proposed project.

Sierra Club argues that the Commission should nevertheless postpone its decision on this matter until the CEC completes its environmental review, a review that Sierra Club suggests could bring forth additional important

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[28] NRG Reply Brief at 11, stating that "[U]nder 'current conditions,' the Puente site is not more vulnerable to coastal hazards than it was in 1983, but is actually less vulnerable."

[29] NRG August 5, 2015 Reply Brief at 10-11.

[30] NRG July 22, 2015 Opening Brief at 25-29.

[31] NRG July 22, 2015 Opening Brief at 22.

considerations as related to reliability. Sierra Club suggests that benefits exist to waiting until the CEC's review is complete, including giving the Commission a comprehensive picture of additional flooding risks and the related reliability concerns.

Sierra Club's argument relies, in part, on Executive Order B-30-15, which directs all state agencies to "take climate change into account in planning and decision making…."[32] Sierra Club also relies on the Commission's "ongoing duty to ensure that utility investments result in infrastructure that is used and useful" and that generating capacity be "deliverable to locations and at times as may be necessary to maintain electric service system reliability and local area reliability."

Section 451 states, in part, "every public utility shall furnish and maintain such adequate, efficient, just, and reasonable service, instrumentalities, equipment, and facilities…as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and public." As stated above, based on the evidence presented in the proceeding, we do not find that the risk based on flooding, sea rise, or tsunami has been shown to compromise reliability and thus do not find that SCE would violate Section 451 through contracting with the NRG Puente Project. In the same way, Executive Order B-30-15 is satisfied. This determination in no way prejudices the CEC's

[32] Sierra Club July 22, 2015 Opening Brief at 2-4, citing to Executive Order B-30-15, issued on April 29, 2015 by Governor Brown, to establish a mid-term greenhouse gas emission reduction target for California of 40 percent below 1990 levels by 2030. All state agencies with jurisdiction over sources of emissions were directed to implement measures to achieve reductions of emissions to meet this target. Executive Order B-30-15 states, in part, "WHEREAS taking climate change into account in planning and decision making will help the state make more informed decisions and avoid high costs in the future."

separate review of the project. All further environmental review of flooding-related issues will be conducted under the CEC's CEQA review process.

3.2. Environmental Justice

Environmental justice matters are raised in this proceeding in connection with the NRG Puente Project. One argument focuses on NRG's proposed use of a brownfield site for the NRG Puente Project. NRG suggests that it has adequately considered all environmental justice concerns by siting the proposed gas-fired generator in a brownfield site.

NRG is correct that the Commission has encouraged the use of brownfield sites for environmental reasons – to site plant on previously disturbed land. D.07-12-052, (and previously D.04-12-048) provided specific direction regarding brownfield siting. Ordering Paragraph 35 states in pertinent part: "IOUs are to consider the use of Brownfield sites first and take full advantage of their location before they consider building new generation on Greenfield sites. If IOUs decide not to use Brownfield, they must make a showing that justifies their decision."

At the same time, the use of a brownfield site can raise environmental justice issues by, for example, siting new facilities on a brownfield site within a historically economically disadvantaged neighborhood. The City of Oxnard argues that to continue to employ such a site near the disadvantaged neighborhood perpetuates the economic injustice issues connected with living near power plants built decades ago.[33]

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[33] On November 19, 2015, in CEC Docket 15-AFC-01 (Application for Certification of Puente Project by NRG), NRG filed Project Enhancement and Refinement, Demolition of Mandalay Generating Station Units 1 and 2, proposing to include the demolition by late 2022 of the two gas-fired steam-generating units at the existing Mandalay Generating Station site, the site where the NRG Puente Project is proposed. Neither NRG's proposal nor the contract presented in this

Footnote continued on next page

A second environmental justice argument focuses on the community surrounding the site. In this instance, the proposed site is near a low-income community. As CEJA states, the Moorpark sub-area includes affluent, predominantly white communities with few pollution sources and many socioeconomic advantages, and it also includes a few low-income communities of color bearing disproportionate environmental burdens.[34] CEJA refers to these areas in this proceeding as "environmental justice" or "disadvantaged" communities. In fact, the City of Oxnard is identified as an environmentally disadvantaged community[35] by the California Environmental Protection Agency's (CalEPA) tool called CalEnviroScreen 2.0.[36] Based on a quantitative analysis of multiple pollution sources and stressors used to rank California's

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proceeding included the demolition at the proposed site. A third generating unit, a jet-engine–powered unit that was commissioned in 1970, and has a generating capacity of approximately 130 MW, will continue to operate and will not be affected by the construction of the NRG Puente Project or the demolition of MGS Units 1 and 2. *See*, November 19, 2015 NRG Project Enhancement and Refinement, Demolition of Mandalay Generating Station Units 1 and 2 filed in CEC Docket 15-AFC-01.

[34] CEJA July 22, 2015 Opening Brief at 2.

[35] Ex. CEJA-1 at 6.

[36] CalEnviroScreen is the tool on which California relies to identify communities where environmental injustice is the greatest. Ex. CEJA-1 at 5. The Commission has relied on CalEnviroScreen as a tool to identify disadvantaged communities. *See* D.15-01-051 at 53-54. The tool "includes two components representing pollution burden – exposures and environmental effects – and two components representing population characteristics – sensitive populations (e.g., in terms of health status and age) and socioeconomic factors." D.15-01-051 at 4 (citing CalEnviroScreen Final Report). CalEnviroScreen 2.0 uses 19 statewide indicators to characterize both pollution burden and population characteristics, as illustrated in the following table. The tool's scientific methodology examines how many indicators are present within each census tract using a scoring system "to weigh[] and sum each set of indicators within pollution burden and population characteristics components." D.15-01-051 at 5 "After the components are scored, the scores are combined to calculate the overall CalEnviroScreen Score." *See* D.15-01-051.

census tracts,[37]some census tracks within the City of Oxnard rank within the top 20% most environmentally burdened cities in California.[38]

CEJA argues that a connection exists between safety and siting in environmentally disadvantaged communities. These communities, such as the City of Oxnard, are disproportionately affected by "environmental pollution and other hazards that can lead to negative public health effects, exposure, or environmental degradation" and "areas with socioeconomic vulnerability."[39] In addition, it is worth noting that the City of Oxnard has hosted two large OTC plants on its beaches for decades – the Mandalay and Ormond generating facility sites.[40] However, these once-through-cooling plants are scheduled for closure in 2020.

CEJA and others cite to D.07-12-052 stating that IOUs "need to provide greater weight" to criteria regarding "disproportionate resource siting in low-income and minority communities and environmental impacts."[41] Ordering Paragraph 4 of D.13-02-015 stated in part: "Any Requests for Offers (RFO) issued by Southern California Edison Company pursuant to this Order shall include the following elements, in addition to any RFO requirements not delineated herein but specified by previous Commission procurement decisions (including Decision 07-12-052) and the authorization and requirements of this decision."

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[37] Ex. CEJA-1 at 4-6.

[38] Ex. CEJA-1 at 8.

[39] CEJA July 22, 2015 Opening Brief at 2, citing to Senate Bill 43, codified at Pub. Util. Code § 2833 (1)(A).

[40] CEJA July 22, 2015 Opening Brief at 3.

[41] *Opinion Adopting Pacific Gas and Electric Company's, Southern California Edison Company's, and San Diego Gas & Electric Company's Long-Term Procurement Plans* (Dec. 21, 2007) at 157.

The dicta cited above from D.07-12-052 remains in effect as guidance, but the Commission to date has not yet provided further specificity regarding how the utilities should implement this guidance. D.07-12-052 provided a wide variety of other direction in Ordering Paragraphs to utilities regarding procurement activities (as have several subsequent decisions in LTPP proceedings, including D.13-02-015 and § 454.5). As noted above, D.07-12-052 provided specific direction regarding brownfield siting in an Ordering Paragraph.

CEJA states in comments on the Alternate Proposed Decision:

> "The Commission is not at liberty to ignore environmental justice in this proceeding in light of the state's anti-discrimination laws, the public utilities code the Commission is particularly bound to implement, and the Commission's own policies and rules, all of which mandate consideration of environmental justice. Accordingly, the APD's limitation of the Commission's review in this proceeding to economic and reliability issues, and exclusion of environmental justice criteria, is untenable."

A major CEJA contention is that Pub. Util. Code § 399.13 mandates environmental justice review in our review of this contract (presumably balanced against other factors required by procurement decisions between 2007 and 2013, such as reliability criteria, cost and a default preference for siting in brownfield locations). Section 399.13(a)(7) states in pertinent part that in both "soliciting and procuring renewable energy…, each electrical corporation shall give preference to renewable energy projects that provide environmental and economic benefits to disadvantaged communities." However, as CEJA itself notes, this section is on its face only applicable to Commission review of renewable procurement. In the future, these differences in criteria with procurement will be addressed in the Integrated Resource Planning Proceeding.

CEJA states that "This proceeding is the first and only opportunity CEJA has to challenge the adequacy of SCE's procurement plan, and due process requires the Commission to properly address it." CEJA is incorrect. This proceeding appropriately considers whether SCE followed its procurement plan, not whether the plan itself was adequate. As discussed herein, pursuant to D.13-12-015, Energy Division approved SCE's procurement plan which included procurement for the Moorpark sub-area in September 2014. If CEJA or another party contended that the process authorized in D.13-02-015 for review of SCE's procurement plan was unlawful, they could have filed an application for rehearing of that decision on this point.

While Energy Division could in theory have required SCE to modify its procurement plan to explicitly include an environmental justice analysis, SCE properly acted upon its approved plan. SCE's procurement process was then vetted by the Independent Evaluator (Sedway Consulting, Inc.), who found it to be reasonable.

This Commission is concerned about environmental justice issues. It is not our interest or intent to approve contracts for pollution-causing power plants in disadvantaged communities or other similarly-impacted areas beyond that which is necessary to maintain reliability at reasonable rates. If we determine that the Puente Project is consistent with the relevant economic and reliability criteria laid out in D.13-02-015 and SCE's procurement plan, the CEC is still required to conduct and complete its review. Environmental justice issues are also applicable within the CEC's CEQA review. The CEC will more fully develop the environmental justice and siting issues in CEC Docket 15-AFC-01 (*Application for Certification of Puente Project by NRG*). The CEC may disapprove or determine that mitigation measures are required due to environmental justice concerns. If the CEC determines that the project should not be permitted for environmental justice or other reasons within its jurisdiction, it will not go forward.

In future procurement applications, we intend to explicitly consider environmental justice issues as part of our review of procurement contracts. In order to ensure that utility procurement applications include sufficient information to ensure such review, the long-term procurement plan (LTPP) proceeding (which is a Rulemaking proceeding applicable to the industry as a whole) will need to specify what information the utility must provide. The Commission recently opened proceeding R.16-02-007 to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements. R.16-02-007 includes potential procurement rule changes within its preliminary scope. Any procurement guidance regarding environmental justice must delineate between the role of the CPUC in evaluating the reasonableness of a proposed procurement contract and the role of the CEC in performing its CEQA-equivalent evaluation. In addition, any procurement guidance must consider how to balance the Commission's long-standing preference for brownfield site development with environmental justice considerations, as well as all other economic and reliability considerations.

3.3. No Deferral to the CEC

As noted above, the Scoping Memo in this proceeding included the question of whether the Commission should approve these contracts prior to completion and a final decision by the CEC of its CEQA review. Several parties argue that the Commission should defer review of the Puente Project contract until the CEC completes its CEQA review process. We have discussed above why this is unnecessary in the context of potential flooding risks. Here we discuss the issue more broadly.

NRG and SCE argued that deferral of consideration of the Puente Project contract would be a substantial departure from Commission precedent. They claim it would create a new standard of review for contracts submitted to the Commission for approval. SCE also contends that, if environmental review is a prerequisite for Commission approval, every project that was the subject of an offer in the LCR RFO would have had to be fully permitted in order to submit a bid. This would have limited the number of eligible bidders and associated competition. Other parties argue that there is sufficient evidence in this proceeding about reliability concerns associated with environmental factors and environmental justice issues to defer our decision until the CEC completes its CEQA review.

In D.15-11-041 at 28-29, regarding SCE's Los Angeles Basin LCR contracts stemming from D.13-02-015, we addressed the issue of our contract review process vis-à-vis the CEC CEQA review process:

> We find that no law specifically requires the Commission wait until CEQA review is complete. We further find that if the project is not approved by the CEC under CEQA, termination of a contract with SCE may result.
>
> We further find that no law specifically requires us to approve contracts before CEQA review is complete. Rather, we use our best judgement in each case to determine the optimal timing of our contract review and disposition. In some cases, we will find that making a contract decision independent of the CEC's CEQA review is reasonable.
>
> In this case, we find that contract approval now, prior to approval of the CEC's CEQA review is reasonable. Misuse of the Commission's contract approval, however, is not permitted. For example, parties are directed to not interfere with the CEC's review

> by, for example, impressing upon the CEC that contract damages may result if the project is not approved under CEQA. The CEC's CEQA review can and should be conducted independent of the parties' opinions regarding potential damages and risks based on the Commission's approval of the underlying contract.

The situation here is similar to that in D.15-11-041. While it is not unusual for non-CPUC environmental review processes to start or be completed before CPUC contract review, it is not a requirement that the project proponent do so. We have reviewed all Commission Decisions and Resolutions on procurement contracts since 2002. In none of those cases has the Commission deferred its decision to the completion of the CEC (or local) environmental review process.

If we were to change our long-standing process here, this would create substantial uncertainty for project developers seeking approval for contracts for new energy projects. Thus the question becomes whether there is a compelling rationale to modify our process.

The CEC has clear jurisdiction to review the environmental impact of the NRG Puente Project. The CEC website (Energy Facilities Licensing Process) at http://www.energy.ca.gov/siting/guide_license_process.html states: "The [CEC's] thorough site certification process provides a timely review and analysis of all aspects of a proposed project, including need, public health and environmental impacts, safety, efficiency, and reliability." Through the certification process an environmental review is performed under CEQA. Typically, CEQA reviews are performed by the "lead" local agency. Under Pub. Res. Code § 25500 et seq., the CEC "has the exclusive authority to certify the construction and operation of thermal electric power plants 50 [MW] or larger…."

The CEC specifically includes environmental justice issues in its review of projects of this type. For example, in the CEC's September 27, 2012 decision reviewing the Pio Pico Energy Center (Docket 11-AFC-1) – which was included in a contract approved by the CPUC - the CEC states: "The record establishes that an environmental justice screening analysis was conducted and that the project, as mitigated, will not have a disproportionate impact on low-income or minority populations." For the Puente Project, the CEC's January 14, 2016 "Puente Power Project Status Report 3" states that "The Applicant has submitted the following in support of their Application for Certification (AFC)…: A revised Environmental Justice analysis."

Thus, it is clear that environmental justice issues are not only within the purview of CEC environmental review, but will be specifically considered in the CEC's review of the Puente Project. Consideration of the NRG Puente Project contract by this Commission does not prejudge the CEC review.

There is no clear or compelling reason based on the record of this proceeding to modify the process of allocating responsibilities between this Commission and the CEC that has been used successfully for many years, including in D.15-11-041. We are satisfied that the siting issues regarding low-income and disadvantaged communities per D.07-12-052 will be adequately and substantially considered in the CEC review process. We will proceed to review the merits of the NRG Puente Project contract.

3.4. Economic and Reliability Review of the Puente Project Contract

The Puente Project contract was submitted by SCE in response to D.13-02-015, which required SCE to procure between 215 and 290 MW of capacity in the Moorpark sub-area. Per D.13-02-015, SCE submitted its procurement plan to Energy Division, which approved it with modifications on August 30, 2013. In accordance with D.06-05-039, SCE retained Sedway Consulting Inc. as an Independent Evaluator to oversee the preparation and administration of the LCR RFO. The Independent Evaluator confirmed that the Puente Contract's economics and general terms and conditions represent the best resource available from the RFO. SCE contends that it showed that it was not possible to procure the required minimum level of incremental capacity using only preferred resources.[42] SCE contends it demonstrated that a gas-fired project must be part of the Moorpark reliability solution, and proved that the Puente Contract was the superior gas-fired offer.

The CAISO analyzed the results of the RFO in the context of the draft 2014-2015 transmission plan local capacity requirement analysis for the Moorpark sub-area and found that the resources selected by SCE in the RFO meet the minimum procurement requirements set forth in D.13-02-015. However, the CAISO indicated that the selected resources "are only a portion of those necessary to meet reliability needs in the Moorpark sub-area. To ensure reliability, the Commission must continue to monitor the development and implementation of other local resources including additional achievable energy efficiency."[43] The CAISO noted that the 2014-2015 transmission plan assumed another 87 MW of energy efficiency would materialize in the Moorpark sub-area by 2024. Accordingly, based on the CAISO's local capacity requirement analyses, we find that the selected RFO resources will enhance the reliable operation of SCE's electrical service and support the reliability of service starting in 2021.

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42 Exhibit SCE-2, Appendix D at D-42.

43 Exhibit CAISO-1/Sparks at 4-5.

SCE held a single RFO for both preferred and conventional resources covering both the LA Basin and Moorpark sub-areas. SCE seeks approval of contracts totaling approximately 274 MW of capacity (excluding the Ellwood refurbishment, which we discuss separately below). This is below the maximum procurement target of 290 MW in D.13-02-015.

SCE's RFO was designed and conducted with oversight from the Independent Evaluator and reviewed by the Energy Division and SCE's Cost Allocation Mechanism Group. The Independent Evaluator stated that it "believe(d) that SCE pursued reasonable and adequate procedures for notifying potential interested parties…On the LCR RFO launch date…SCE issued a press release and emailed over 3,400 industry contacts (compiled from previous power supply solicitations, regulatory service lists, etc.) that the LCR RFO had been released and invited them to participate. SCE also notified all CAM members of the LCR RFO's launch."[44] The Independent Evaluator "concluded that SCE did a good job of publicizing the 2013 LCR RFO solicitation, and that the solicitation was quite robust, as evidenced by the substantial response that it received from the bidding community."[45]

D.13-02-015 made several Findings of Fact which are relevant to our independent analysis of the Puente Project contract. Finding of Fact 26 stated: "Gas-fired resources at the current OTC sites are certain to meet the ISO's criteria for meeting LCR needs. Other resources can also meet or reduce LCR needs, but may not be effective in doing so." Finding of Fact 38 states: "The ISO has shown that there is a need for in-area generation with operational characteristics similar

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[44] Exhibit SCE-2, Appendix D at D-34 to D-35.

[45] Exhibit SCE-2, Appendix D at D-35.

to retiring OTC plants in the Moorpark sub-area of the Big Creek/Ventura local area." Finding of Fact 39 states: "The most likely locations for [sic] to meet LCR needs in the Moorpark sub-area are the sites of the current OTC plants."

The CAISO states in its brief that its local capacity requirement analyses show that the procured RFO resources will help maintain the reliable operation of SCE's electrical service. In addition, the CAISO states that SCE's required consultations with the CAISO during the RFO process were consistent with the Commission's directives and necessary to ensure that the selected resources met identified capacity needs. Through its consultations with SCE, the CAISO was able to ensure that the selected RFO resources do in fact meet system needs. If the Puente Project is delayed or rejected, the CAISO is concerned that it will increase the possibility that there will be insufficient resources to meet local capacity requirements when generation facilities in the Moorpark sub-area retire at the end of 2020. We agree with the CAISO that the Puente Project is necessary to meet the identified local reliability need in the Moorpark sub-area. The need determination of the Moorpark sub-area in D.13-02-015 depended upon the retirement of Mandalay Units 1 and 2 and Ormond Beach once-through-cooling generation units.

CEJA casts doubt on the reasonableness of the Puente Project contract. CEJA claims in its brief that there is no evidence to support a finding that SCE acted reasonably in assigning NRG's offers key qualitative value based on its fear that NRG may retire the Mandalay and Ellwood peakers. CEJA also contends that "NRG Oxnard's economic ranking as the least cost/best fit GFG offer[], and its ultimate selection, turned on those unfounded reliability concerns."

As SCE explains in its reply brief at 11, the qualitative factors reinforced SCE's quantitative assessment that the NRG Energy Center was the best option to meet the LCR need. SCE's assessment combining qualitative and quantitative factors is consistent with its procurement plan. The outcome of SCE's RFO was found by the Independent Evaluator to be the best resource available from the RFO and was found by the CAISO to meet the LCR needs of the Moorpark sub-area.

We find that the results of SCE's 2013 RFO are consistent with the CAISO's planning assumptions in the 2014-2015 transmission plan and support the safe and reliable operation of SCE's electrical service. The record shows that the LCR RFO followed a thorough process and elicited a robust response. We find the contract process to have been reasonable and in compliance with D.13-02-015. The Puente plant is expected to provide necessary grid reliability benefits at a reasonable cost to ratepayers. We find the results of the contract process regarding the selection of the Puente Project contract to be reasonable and consistent with D.13-02-015.

4. 54 MW Gas-Fired Generation NRG Ellwood Project – Offer 447021

Today's decision defers consideration of the ten-year contract for the Ellwood Project located in Santa Barbara County to a separate decision in this docket.

The Ellwood Project includes the refurbishment of the Ellwood plant, an existing gas-fired generation peaker plant in Goleta.[46] Ellwood is a combustion

[46] Ex. SCE-1 at 57.

turbine generating unit built in 1974. Historically, Ellwood has not been a reliable resource.[47] The Project is located adjacent to a residential area.[48]

4.1. Parameters of RFO

The Ellwood contract falls outside of the parameters of the RFO and the need determination, as defined D.13-02-015. In D.13-02-015, the Commission ordered SCE to procure a maximum of 290 MW in the Big Creek/Ventura local reliability area. The capacity of the Ellwood contract results in SCE contracting for amounts that exceed this limitation.[49] Importantly, D.13-02-015 set this maximum to reflect the maximum amount of potential costs that the Commission found reasonable to impose on ratepayers. The maximum amount was the limit of the LCR need the Commission determined, and the Commission has not yet found the need for any further LCR procurement together with the related costs reasonable for ratepayers.

Moreover, under the terms of the RFO, all contract capacity needs to be incremental. In D.14-02-040, the Commission found that only incremental capacity of existing plants, such as Ellwood, or repowered plants could participate in long-term RFOs.[50] The rationale behind this requirement in D.14-02-040 was to create a level playing field among bidders, an essential

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[47] Ex. SCE-1 at 57. *See also*, ORA August 5, 2015 Reply Brief at 3, suggesting that because Ellwood has not historically been a very reliable resource, the need for Ellwood to maintain reliability is unclear and further weakens any assertion that Ellwood is necessary to maintain reliability.

[48] The project is located at 30 Las Amas Road, Goleta, California 93117 and the commercial operation date is June 1, 2018. Ex. SCE-1 at 55. The project is located approximately 1000 ft. from a public school, the Ellwood School.

[49] ORA July 22, 2015 Opening Brief at 5.

[50] D.14-02-040 at 28.

component to a well-functioning market. All parties agree that Ellwood is not new or incremental capacity. Ellwood is currently operating, and under a contact with NRG. Therefore, the project does not fall within the definition of incremental resource and, under the terms of the Commission's prior decisions, the 54 MW contract to refurbish the Ellwood facility does not count toward the LCR procurement authorization required in D.13-02-015.[51]

SCE essentially combined the Ellwood contract (and an associated 0.5 MW storage contract) with the Moorpark LCR procurement contracts into one application. Arguing that this proceeding is the appropriate forum for the Commission's consideration of the Ellwood contract, NRG contends an application proceeding such as this one is the appropriate means to seek approval for a ten-year contract, such as the Ellwood contract, and no reason exists to submit a second, separate application. (NRG July 22, 2015 Opening Brief at 46.)

The Scoping Memo in this proceeding includes the following issue for consideration: Is the 54 MW Ellwood Refurbishment project appropriate for the Commission to consider in this proceeding and, if so, is the contract reasonable?

In SCE's August 30, 2013 approved procurement plan pursuant to D.13-02-015 (at p. 15-16), SCE provides the following additional statements regarding the Moorpark sub-area:

> The CAISO's analysis of LCR needs in the Moorpark sub-area focused on the loss of the Moorpark–Pardee number one, two, and three transmission lines. This would result in voltage collapse for the Moorpark sub-area. However, in addition to

[51] Sierra Club July 22, 2015 Opening Brief at 5-6, *citing to* D.14-02-040, *Modifying Long-Term Procurement Planning Rules* (also known as the LTPP Track 3 decision).

> the loss of the Moorpark-Pardee lines, there is another transmission outage that, without sufficient local generation capacity support, could create a reliability concern in this area. As can be seen from Figure II-3, the Goleta substation area is served radially from Santa Clara substation by two 230 kV lines, Santa Clara-Goleta No. 1 and No. 2. The two Santa Clara-Goleta 230 kV lines are co-located on a single tower corridor through rugged mountainous terrain in a wooded area that is subject to natural hazards including soil erosion and wildfires. If an outage occurred on the two Santa Clara-Goleta 230 kV lines, SCE can serve approximately two-thirds of the peak loads served by Goleta substation by being transferred to an adjacent 66 kV system once a proposed upgrade to that system that presently awaiting CPUC approval is completed. However, the time period to restore full service to load served by Goleta substation could be significant. Due to the rugged terrain, loss of the Santa Clara-Goleta lines due to environmental hazards could result in rolling blackouts in this area for an extended period. There is significant value to the local communities in seeking generation sited in this area. (footnote deleted)

NRG and SCE seek to justify this contract based on the concerns about the challenges of maintaining system reliability in the Goleta area.[52] In addition, while SCE and NRG acknowledge that the contract falls outside of the parameters of the RFO, SCE and NRG urge the Commission to evaluate and approve of a power purchase agreement for Ellwood in this proceeding because, by acting now, the Commission might, according to SCE and NRG, be able to obtain a more favorable outcome in terms of lower costs to ratepayers and increased reliability. SCE and NRG also point to the companion contract that NRG presented as a package with Ellwood - the contract for 0.5 MW of IFOM

[52] SCE July 22, 2015 Opening Brief at 11; Ex. SCE-1 at 57.

storage, as a reason to approve of the 54 MW Ellwood project. Also, as suggested by SCE and the Independent Evaluator, the costs of Ellwood could be modest compared to the reliability benefits. Finally, if SCE waits for NRG to retire Ellwood, the Commission might have to reassess the need in that area and for Ellwood and then order SCE to fulfill that need, very likely at a cost much greater than the proposed Ellwood refurbishment.[53] On the other hand, CEJA argues[54] that there is no substantial evidence in the record to support a decision for the Ellwood plant, no evidence that Ellwood is faulty or unreliable, or needs to be refurbished, and no legal authority to close or refurbish a gas-fired plant based on age alone.

We find that it is appropriate to consider the Ellwood contract in this proceeding. SCE clearly stated in its approved procurement plan that it would evaluate reliability issues in Goleta. Further, parties have litigated SCE's proposal for the Ellwood refurbishment contract; there is no value in starting anew and duplicating the efforts already undertaken by the parties. However, the record in this proceeding does not appear to be fully developed enough to decide whether to approve the Ellwood contract at this time.

To determine if the Ellwood contract is reasonable, it is necessary to determine if there is a reliability need that it would meet. D.13-02-015 required that SCE procure new resources to fill the Moorpark sub-area reliability need. Goleta is within the Moorpark sub-area, but the current Ellwood facility was considered by the CAISO to be an existing operational resource in the 2012 LTPP

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53 SCE July 22, 2015 Opening Brief at 11-12.

54 Reply Brief at 13-14

proceeding in which D.13-02-015 was decided. Thus, the Ellwood peaker would not be eligible to fill the identified reliability need in the Moorpark sub-area.

The CAISO states in its brief that if the Ellwood Peaker is not refurbished, and instead retires, the LCR needs in the Moorpark sub-area will increase. The CAISO also includes the Ellwood peaker in its 2014-2015 TPP. SCE states in its brief that the Ellwood refurbishment, which will provide a new 30-year design life for an existing gas-fired generation facility that is close to the end of its useful life, is necessary to maintain system reliability in the Moorpark LCR area, and in particular, in the Goleta sub-area absent other resources being developed.

With the approval of the contract for the Puente Project and 12 MW of preferred resources in this decision, SCE has filled more than the minimum procurement of 215 MW in the Moorpark sub-area required by D.13-02-015. Typically, we would consider if there are any further local reliability needs through our LTPP proceeding (currently R.16-02-007). The preliminary scope of that proceeding, as set forth in the Rulemaking at 12, includes: "To the extent necessary, identify CPUC-jurisdictional needs for new resources to meet local, flexible, or system resource adequacy requirements and consider authorization of procurement to meet that need." However, the Rulemaking at 16-17 also states: "we do not anticipate that the modeling refinements addressed in this new proceeding will lead to procurement decisions in this two-year cycle, absent any unforeseen circumstances that could potentially affect grid reliability."

Although it may be incomplete, there is already a record in this proceeding regarding the reliability circumstances in the Moorpark and Goleta areas. Therefore, this proceeding is the most efficient procedural venue to establish if there is a separate local reliability need in the Goleta area, given that the identified Moorpark sub-area need identified in D.13-02-015 has been filled. If we determine there is an additional unmet local reliability need in the Goleta area that needs to be filled, we will consider if the Ellwood refurbishment contract is the best resource to do so.

Rather than delay consideration of the Moorpark LCR contracts until the record regarding reliability needs and the Ellwood contract is complete, we will defer consideration of Goleta reliability matters to a separate decision in this docket. For the purposes of the forthcoming decision, we seek to ensure the record includes the following information:

1. Is the Ellwood facility currently under contract between SCE and NRG, and, if so, for how long?
2. Is there a specific unmet local reliability need in the Goleta area absent the Ellwood facility, given the approvals in this decision? If so, what is the amount of this need, and in what timeframe does it occur?
3. What is the best way to fill any local reliability need in the Goleta area?
4. Should there be a new RFO or other process to identify resources to meet any unmet local reliability need in the Goleta area?
5. Should the Ellwood refurbishment contract and associated storage contract be approved at this time to meet any unmet local capacity need, or should the Ellwood refurbishment/storage contract be required to participate in any new RFO (or other process) to meet any unmet local capacity needs?

5. 0.5 MW NRG Energy Storage Project – Offer 447030

The ten-year, 0.5 MW energy storage contract[55] between SCE and NRG California South LP at the Ellwood site will also be considered in a subsequent

[55] Ex. SCE-1 at 54.

decision in this docket. The Ellwood refurbishment is required to facilitate the addition of the new 0.5 MW energy storage facility at the Ellwood site, as the two contracts were linked together by NRG as a mutually exclusive offer.[56]

6. Remaining Offers

SCE presented several additional contracts for Commission consideration. Six contracts are for energy efficiency (totaling 6 MW of capacity), and two contracts are for renewable distributed generation (totaling 5.66 MW of capacity).[57] We find these contracts reasonable and consistent with D.13-02-015. These contracts are approved.

7. Cost Allocation Mechanism Treatment

The cost treatment and allocation proposals were uncontested. On April 17, 2015, a joint motion was filed seeking to enter into the record a Joint Memorandum of Understanding with respect to cost allocation issues in this proceeding.[58]

Based upon our review, we find that any payments to be made by SCE pursuant to the contracts are recoverable in full by SCE through the ERRA proceeding.

Moreover, SCE is authorized to allocate the benefits and costs of the contracts entered into as a result of the LCR RFO to all benefitting customers in accordance with D.13-02-015 and D.14-03-004. We also find that such cost allocation should be made consistent with the April 17, 2015 motion and memorandum of understanding.

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[56] NRG July 22, 2015 Opening Brief at 45.

[57] Ex. SCE-1 at 3, Table I-1.

[58] This motion was filed by SCE, AReM and DACC.

Lastly, we approved SCE's plan for the allocation of costs and benefits to all benefitting customers set forth in Chapter 9 of Exhibit SCE-1. SCE may establish the LCR Products Balancing Account, as needed.

8. Motions

All outstanding motions to correct transcript errors, to file documents confidentially, and for party status are granted. SCE's motion for leave to amend rebuttal testimony is granted. The motions dated July 21, 2015 and August 17, 2015 by ORA to admit exhibits, file under seal, and amend exhibits are granted.

9. Comments on Alternate Proposed Decision

The alternate proposed decision of Commissioner Carla J. Peterman in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on March 3, 2016 by SCE, ORA, CAISO, City of Oxnard, CEJA, EnerNOC, Sierra Club, WBA and NRG, and reply comments were filed on March 8, 2016 by ORA, SCE, CAISO, City of Oxnard, Sierra Club, CBD, and NRG.

The alternate decision was revised in response to comments as follows:

- Clarify the flooding risks pertain to both the contract and the expected life of the plant;
- Address the applicability of Sections 451, 454.5 and 399.13;
- Address the significance of dicta in D.07-12-052 regarding environmental justice;
- Reference previous decisions which included procurement requirements regarding siting in brownfield locations, and other procurement mandates;
- Clarify the relationship between the CPUC and CEC roles in evaluating environmental justice issues with regard to

the NRG Puente Project, including citing language from D.15-11-041;

- Address the conduct of the RFO and SCE's compliance with procurement directives in D.13-02-015;
- Determines that the Puente Project is necessary to meet the identified local reliability need in the Moorpark sub-area;
- Address the relationship between this proceeding and the LTPP Rulemaking regarding reliability in the Goleta area;
- Provide guidance regarding record development for a subsequent decision in this docket about procurement in the Goleta area; and
- Provide guidelines for record development in R.16-02-007 regarding environmental justice.

10. Assignment of Proceeding

Michel Peter Florio is the assigned Commissioner and Regina M. DeAngelis is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. The results of the RFO, with the exception of the Ellwood contract, substantially comply with the procurement directives in D.13-02-015.
2. During the term of the Puente Project contract and the expected life of the plant, the risk of coastal flooding has not been shown to compromise the reliability of the proposed project.
3. D.07-12-052 included dicta regarding environmental justice considerations in procurement solicitations.
4. D.07-12-052 and subsequent LTPP decisions up to D.13-12-015 included Ordering Paragraphs regarding a preference for brownfield sites and other requirements for procurement solicitations.

5. The Energy Division reviewed and approved SCE's procurement plan pursuant to D.13-02-015.

6. The SCE procurement plan involved an all-source RFO.

7. The NRG Puente Project would be located in a brownfield site.

8. Additional review of safety, reliability, and environmental justice issues regarding the NRG Puente Project will be performed by the California Energy Commission.

9. The NRG Puente Project contract's economics and general terms and conditions represent the best resource available from the RFO.

10. SCE's assessment combining qualitative and quantitative factors in evaluating the NRG Puente Project contract is consistent with its procurement plan.

11. The results of SCE's 2013 RFO are consistent with the CAISO's planning assumptions in the 2014-2015 transmission plan.

12. The selected RFO resources will enhance the reliable operation of SCE's electrical service and support the reliability of service starting in 2021.

13. The Puente Project is necessary to meet the identified local reliability need in the Moorpark sub-area. The need determination of the Moorpark sub-area in D.13-02-015 depended upon the retirement of Mandalay Units 1 and 2 and Ormond Beach once-through-cooling generation units.

14. SCE's LCR RFO followed a thorough process and elicited a robust response.

15. The record is incomplete regarding evaluation of the reliability need for the Ellwood contract and whether the Ellwood contract is the best way to meet any such need.

16. Under the terms of the contracts, the energy storage contract with NRG California South, located at the site of Ellwood, is not available if the Commission refrains from approving Ellwood at this time.

17. The terms and conditions of the six contracts for energy efficiency (totaling 6 MW of capacity) and the two contracts are for renewable distributed generation (totaling 5.66 MW of capacity) are reasonable and consistent with D.13-02-015.

18. The cost allocation and recovery proposals by SCE together with the April 17, 2015 Joint Memorandum of Understanding are reasonable.

Conclusions of Law

1. Southern California Edison Company substantially complied with the procurement directives in Decision 13-02-015.

2. The California Energy Commission has jurisdiction to review environmental issues, including issues about flooding and environmental justice in its review of the NRG Puente Project.

3. Dicta from D.07-12-052 regarding environmental justice considerations in procurement solicitations should be viewed as guidance.

4. Pub. Util. Code § 399.13 does not apply to all-source procurement contracts.

5. There is no clear or compelling reason based on the record of this proceeding to modify the process of allocating responsibilities between this Commission and the CEC that has been used successfully for many years, by deferring Commission contract review until the CEC environmental review is complete.

6. The results of the contract process regarding the selection of the Puente Project contract are reasonable and consistent with D.13-02-015.

7. The 20-year contract for gas-fired generation (totaling 262 MW of capacity) with NRG for a new simple cycle peaking facility, the NRG Puente Project, should be approved.

8. The ten-year agreement with NRG California South for the existing 54 MW Ellwood Generating Station (Ellwood) should be considered in a subsequent decision in this docket.

9. The energy storage contract with NRG California South (0.5 MW) should not be approved at this time.

10. Six contracts for energy efficiency (totaling 6 MW of capacity) are reasonable and should be approved.

11. Two contracts for renewable distributed generation (totaling 5.66 MW of capacity) are reasonable and should be approved.

12. SCE has substantially satisfied the procurement requirements of D.13-02-015 and is relieved from the requirement to procure additional resources as part of the RFO required by D.13-02-015.

13. Any payments to be made by SCE pursuant to the approved contracts are recoverable in full by SCE through the ERRA proceeding.

14. SCE is authorized to allocate the benefits and costs of the contracts entered into as a result of the LCR RFO to all benefitting customers in accordance with D.13-02-015 and D.14-03-004.

15. SCE's plan for the allocation of costs and benefits to all benefitting customers set forth in Chapter 9 of Exhibit SCE-1 is reasonable.

16. The April 17, 2015 motion regarding cost allocation is reasonable and should be granted.

17. SCE should be allowed to establish the LCR Products Balancing Account, as needed.

O R D E R

IT IS ORDERED that:

1. All contracts presented by Southern California Edison Company are accepted and approved, with the exception of 447021 (Ellwood) and 447030 (Energy Storage). These contracts will be considered in a subsequent decision in this docket.

2. Southern California Edison Company shall allocate costs associated with the contracts approved in this proceeding according to Chapter 9 of Exhibit SCE-1 and the April 17, 2015 Joint Memorandum of Understanding.

3. Southern California Edison Company shall establish the Local Capacity Requirement Products Balancing Account.

4. All rulings on motions issued by the Administrative Law Judge during the proceeding are adopted. All outstanding motions to correct transcript errors, to file documents confidentially, and for party status are granted. Southern California Edison Company's motion for leave to amend rebuttal testimony is granted. The motions dated July 21, 2015 and August 17, 2015 by Office of Ratepayer Advocates to admit exhibits, file under seal, and amend exhibits are granted.

5. Application 14-11-016 remains open.

This order is effective today.

Dated May 26, 2016, at San Francisco, California.

MICHAEL PICKER
President
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
CARLA J. PETERMAN
LIANE M. RANDOLPH
Commissioners

EXHIBIT B

ALJ/DMG/rs6 **Date of Issuance 2/13/2013**

Decision 13-02-015 February 13, 2013

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

DECISION AUTHORIZING LONG-TERM PROCUREMENT FOR LOCAL CAPACITY REQUIREMENTS

TABLE OF CONTENTS

TITLE **PAGE**

TABLE OF CONTENTS
(cont.)

TITLE **PAGE**

DECISION AUTHORIZING LONG-TERM PROCUREMENT FOR LOCAL CAPACITY REQUIREMENTS

1. Summary

In this decision, we authorize Southern California Edison Company (SCE) to procure between 1400 and 1800 Megawatts (MW) of electrical capacity in the West Los Angeles sub-area of the Los Angeles (LA) basin local reliability area to meet long-term local capacity requirements (LCRs) by 2021. SCE is also authorized to procure between 215 and 290 MW of the Moorpark sub-area of the Big Creek/Ventura local reliability area. The LCRs require resources be located in a specific transmission-constrained area in order to ensure adequate available electrical capacity to meet peak demand, and ensure the safety and reliability of the local electrical grid.

For the defined portion of the LA basin local area, at least 1000 MW, but no more than 1200 MW of this capacity must be procured from conventional gas-fired resources. At least 50 MW must be procured from energy storage resources. At least 150 MW of capacity must be procured through preferred resources consistent with the Loading Order in the Energy Action Plan, or energy storage resources. SCE is also authorized to procure up to an additional 600 MW of capacity from preferred resources and/or energy storage resources. In addition, SCE will continue to obtain resources which can be used in these local reliability areas through processes defined in energy efficiency, demand response, renewables portfolio standard, energy storage and other relevant dockets.

The long-term LCRs are expected to result from the retirement of thousands of MW from current once-through cooling generators due to compliance with State Water Quality Control Board regulations. 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. Energy storage resources may also be available.

In the next long-term procurement proceeding, expected to commence in 2014, we will evaluate whether there are additional LCR needs for local reliability areas in California.

SCE is directed to begin a solicitation process to procure authorized LCR resources. The first step is a plan to issue one or more Request for Offers and/or to enter into cost-of-service contracts per Assembly Bill 1576 (Stats 2005, ch. 374). SCE should also actively pursue locally-targeted and cost-effective preferred resources. SCE's procurement plan shall be consistent to the extent possible with the multi-agency Energy Action Plan, which places cost-effective energy efficiency and demand response resources first in the Loading Order, followed by renewable resources and then fossil-fuel resources. Energy storage resources should be considered along with preferred resources. SCE's procurement plan should take into account the technical reliability requirements of the California Independent System Operator. Energy Division will review SCE's adherence to these and other requirements before SCE commences its public solicitation process.

We consider today's decision a measured first step in a longer process. If as much or more of the preferred resources we expect do materialize, there will be no need for further LCR procurement based on current assumptions. If circumstances change, there may be a need for further LCR procurement in the next long-term procurement proceeding. We are confident that today's decision is the appropriate and considered step at this time.

SCE is directed to file an Application for each local reliability area seeking approval of contracts arising from the procurement process we authorize today. The Applications are expected in late 2013 or early 2014. Separately and earlier, SCE may also file applications for gas-fired generation in order to expedite review of such contracts. This decision establishes criteria for review of SCE's forthcoming Applications. A significant aspect of that review will be to ensure consistency with the Loading Order.

2. Background

This proceeding is the successor proceeding to rulemakings dating back to 2001 intended to ensure that California's major investor-owned utilities (IOUs) can maintain electric supply procurement responsibilities on behalf of their customers. The most recent predecessor to this proceeding was Rulemaking (R.) 10-05-006. As stated in the order originating this rulemaking in Ordering Paragraph 3, the record developed in R.10-05-006 is "fully available for consideration in this proceeding" and is therefore incorporated into the record of this proceeding.

In the Scoping Memo for this proceeding, issued on May 17, 2012, the general issues for the 2012 procurement planning cycle were divided into three topics[1]:

1. Identify Commission-jurisdictional needs for new resources to meet local or system resource adequacy (RA), renewable integration, or other requirements and to

[1] Scoping Ruling at 5.

consider authorization of investor-owned utility (IOU) procurement to meet that need. This includes issues related to long-term renewable planning and need for replacement generation infrastructure to eliminate reliance on power plants using once-through cooling technology (OTC);

2. Update, and review individual IOU bundled procurement plans consistent with Public Utilities Code § 454.5;[2] and
3. Develop or refine procurement rules that were not resolved in R.10-06-005, and consider other emerging procurement policy topics.

The Scoping Memo divided the proceeding into three Tracks:

1. Track 1: Local Reliability
2. Track 2: System Reliability
3. Track 3: Procurement Rules and Bundled Procurement Plans

This is the decision for Track 1 of this proceeding. In recent years the California Independent System Operator (ISO or CAISO) has performed an annual Local Capacity Requirements (LCR) study, which is filed in the Commission's RA proceeding. This study is used to adopt local RA procurement requirements for the next year; for example, requirements for 2013 were adopted in Decision (D.) 12-06-025, in the 2012 RA proceeding (R.11-10-023).

In RA decisions, the Commission has focused on LCR for local reliability for one forward year. In the Local Reliability track of this proceeding, we consider authorizing long-term procurement of new infrastructure for local

[2] All statutory references are to the Public Utilities Code, unless otherwise noted.

reliability purposes for the years 2021 and beyond.[3] As the Scoping Memo stated, the end result of this track of the proceeding should be that the IOUs and/or other load-serving entities (LSEs) will be authorized or required to contract for local reliability needs over the next several years, to the extent that the Commission finds there is such a need.

The main driver of local capacity requirements is that around 4900 megawatts (MW) of OTC plants in the local transmission-constrained areas of the Los Angeles (LA) basin local area may retire in the next several years, as well as other OTC plants in the Big Creek/Ventura and San Diego local areas because of State Water Resources Control Board (SWRCB) regulations.[4][5] By 2021, approximately 7000 MW of OTC capacity is expected to retire in the LA basin local area and the Big Creek/Ventura local area.

"Once-through cooling" is a method to dispose of waste heat produced by a power plant (heat not converted into electricity) in which cold ocean or river water is pumped one time through the plant, absorbing and carrying out the plant's waste heat back into the ocean or river. Because the water pumped through the plant and back into the ocean or river can cause considerable stress on the local aquatic ecosystems, the result is considered as water pollution under Section 316(b) of the Federal Clean Water Act. In California, the SWRCB is the

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[3] A local capacity area is a geographic area that does not have sufficient transmission import capability to serve the customer demand in the area without the operation of generation located within that area.

[4] *See* State Water Resources Control Board Resolution No. 2010-0020, adopted on May 4, 2010, effective 9/28/2010; Attachment 1, Milestone No. 26 at 14.

[5] Issues related to infrastructure needs for the San Diego local area are being considered in Application (A.) 11-05-023 and will not be in the scope of this proceeding, except to the extent that any decisions in that proceeding inform the record.

state agency that enforces the Federal Clean Water Act. As part of such regulation, the SWRCB now requires that most of these aging coastal fossil-fuel plants become compliant with their policy by the end of the year 2020, with some exceptions with different dates. Compliance can occur either through changing cooling intake to no longer use once-through cooling, or by reducing entrainment by 93%. Most generators in their plans filed with the SWRCB have indicated that they are pursuing the first option, which implies retirement or repowering of the facility.

Table 1 shows the plants, locations and expected compliance dates for OTC plants in the LA basin and Big Creek Ventura local areas.[6]

[6] The San Onofre Nuclear Generating Stations (SONGS) plants are OTC plants, but are not included in this analysis.

TABLE 1

Once-Through Cooling Plants Compliance Schedule Per State Water Resources Control Board

Los Angeles Basin Local Reliability Area

Unit Name	Owner	NQC	Compliance date
		175	12/31/20
		175	12/31/20
		332	12/31/20
		336	12/31/20
		498	12/31/20
		495	12/31/20
El Segundo Unit 3	NRG	335	12/31/15
El Segundo Unit 4	NRG	335	12/31/15
Huntington Beach Unit 1	Edison Mission Energy	226	12/31/20
Huntington Beach Unit 2	Edison Mission Energy	226	12/31/20
Huntington Beach Unit 3	Edison Mission Energy	225	12/31/12
Huntington Beach Unit 4	Edison Mission Energy	227	12/31/12
Redondo Beach Unit 5	AES	179	12/31/20
Redondo Beach Unit 6	AES	175	12/31/20
Redondo Beach Unit 7	AES	493	12/31/20
Redondo Beach Unit 8	AES	496	12/31/20

Big Creek - Ventura Local Reliability Area

Unit Name	Owner	NQC	Compliance date
Mandalay Unit 1	GenOn	215	12/31/20
Mandalay Unit 2	GenOn	215	12/31/20
Ormond Beach Unit 1	GenOn	741	12/31/20
Ormond Beach Unit 2	GenOn	775	12/31/20

Units and compliance dates from:
http://www.waterboards.ca.gov/publications_forms/publications/factsheets/docs/oncethroughcooling0811.pdf

As noted, Table 1 excludes SONGS

* Net Qualified Capacity (NQC) from:
http://www.cpuc.ca.gov/NR/rdonlyres/C6BE7182-D647-4C70-B1AC-5D3A1CE207C3/0/CPUCNQCLocalAreaData_ComplianceYear2012.xls

In a settlement agreement approved by the Commission in D.12-04-046 in the previous long-term procurement plan Rulemaking,[7] parties to the agreement found that in the first quarter of 2012 the ISO would present a study of integration of renewable resources into local transmission-constrained areas, along with a study of the effect of potential OTC plant retirements. The adopted settlement included a recommendation that the Commission issue a decision by the end of 2012 on the need for sufficient resources to integrate the number of renewable resources coming online to meet a 33% renewable portfolio standard by 2020 and the retirement of OTC plants.

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[7] This settlement was entitled: "Motion For Expedited Suspension Of Track 1 Schedule, And For Approval Of Settlement Agreement Between And Among Pacific Gas And Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, The Division Of Ratepayer Advocates, The Utility Reform Network, Green

Footnote continued on next page

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 demand-side resources, followed by renewable resources, and only then in clean conventional electricity supply." (Energy Action Plan 2008 Update at 1.)

In the 2008 Energy Action Plan Update at 20, the Commission further interpreted this directive to mean that the IOUs are obligated to follow the loading order on an ongoing basis. Once procurement targets are achieved for preferred resources, the IOUs are not relieved of their duty to follow the Loading

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Power Institute, California Large Energy Consumers Association, The California Independent System Operator, The California Wind Energy Association, The California Cogeneration Council, The Sierra Club, Communities For A Better Environment, Pacific Environment, Cogeneration Association Of California, Energy Producers And Users Coalition, Calpine Corporation, Jack Ellis, Genon California North LLC, The Center For Energy Efficiency And Renewable Technologies, The Natural Resource Defense Council, NRG Energy, Inc., The Vote Solar Initiative, And The Western Power Trading Forum."

Order. 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.

This clarified Loading Order is a departure from the Commission's previous position of procuring energy efficiency and demand response, then renewable energy, and then allowing "additional clean, fossil-fuel, central-station generation," because "preferred resources require both sufficient investment and adequate time to 'get to scale.'" (D.04-06-011, footnote 22 at 31). Instead of procuring a fixed amount of preferred resources and then procuring fossil-fuel resources, the IOUs are required to continue to procure the preferred resources "to the extent that they are feasibly available and cost effective." (D.12-01-033 at 21.) While procuring a fixed amount of preferred resources provides flexibility and a clearer idea of how to approach the procurement process, the ongoing Loading Order approach is more consistent with Commission policy. (*Id.*)

A prehearing conference (PHC) was held on April 18, 2012. At the PHC, the ISO stated that it had completed a study of LCRs through 2016 in its Transmission Planning Process. The ISO also completed a study of local capacity needs related to expected or potential retirements of OTC plants through 2021. These studies are consistent with the studies anticipated in the settlement agreement adopted in D.12-04-046. In its comments on the scope of this proceeding and at the PHC, the ISO maintained that it cannot evaluate any additional renewable portfolio scenarios beyond those already in the record of R.10-05-006 in time for a decision by the Commission by the end of 2012.

In this proceeding, parties were given the opportunity to present evidence that the ISO's studies should be modified, or that the Commission should consider additional factors beyond the ISO's studies, for the purposes of determining local reliability needs. The Scoping Memo presented a list of specific issues for this phase of the proceeding.

The ISO served its testimony on May 23, 2012. Parties served testimony in response to the ISO and on issues from the Scoping Memo on June 25, 2012. The assigned Commissioner issued a Ruling on July 13, 2012 seeking clarification on certain issues raised in opening testimony. Parties (including the ISO) served reply testimony (including issues from the assigned Commissioner's Ruling) on July 23, 2012.[8] Evidentiary hearings were held August 7-10 and August 13-17, 2012. Briefs were filed on September 24, 2012 and Reply Briefs were filed on October 7, 2012. Per a Ruling issued September 14, 2012, comments were filed on October 9, 2012 regarding certain implementation issues arising from a workshop on September 7, 2012. This track of the proceeding was submitted on October 9, 2012.

The parties which served testimony in Track 1 of this proceeding are[9]: AES Southland (AES); Alliance for Retail Energy Markets, Direct Access

[8] Certain parties served supplemental and other versions of testimony on other dates with permission of the Administrative Law Judge (ALJ).

[9] Parties serving testimony that was subsequently stricken from the record are not included in this list.

Customer Coalition and Marin Energy Authority (collectively, AReM); California Cogeneration Council (CCC); California Energy Storage Alliance (CESA); California Environmental Justice Alliance (CEJA); CAISO or ISO; California Large Energy Consumer's Association (CLECA); Calpine Corporation (Calpine); Center for Energy Efficiency and Renewable Technologies (CEERT); Cogeneration Association of California (CAC); Division of Ratepayer Advocates (DRA); EnerNOC, Inc. (EnerNOC); GenOn Energy, Inc. (GenOn); Independent Energy Producers Association (IEP); Natural Resources Defense Council (NRDC); Pacific Gas and Electric Company (PG&E); San Diego Gas and Electric Company (SDG&E); Southern California Edison Company (SCE); South San Joaquin Irrigation District (SSJID); The Utility Reform Network (TURN); The Vote Solar Initiative (Vote Solar); and Women's Energy Matters (WEM). Testimony from each of these parties was received into evidence at the evidentiary hearing.

Each of these parties also filed comments and/or briefs. In addition, comments and/or briefs were filed by Alliance for Nuclear Responsibility (ANR); Beacon Power, LLC; City and County of San Francisco; Clean Coalition; Community Environmental Council; Distributed Energy Consumer Advocates; Ormat Technologies; and Sierra Club California (Sierra Club).

3. Long-Term Local Capacity Requirements for the LA Basin Local Area – Party Positions

3.1. ISO

Overall, the ISO recommends the long-term procurement of approximately 2400 MW in the LA basin local area to meet LCR needs in 2021, if the generation is selected from the most effective sites. This amount includes a specific identified need for 225 MW in the Ellis sub-area of the LA basin local area.[10] The ISO recommends that the Commission authorize this procurement by the end of 2012 and that SCE begins a contracting process in 2013. The ISO found that potential retirement of OTC generation in the PG&E service territory is not expected to create local capacity deficiencies.[11]

The ISO performed local capacity technical studies to determine the minimum amount of resources within a local capacity area needed to address reliability concerns following the occurrence of various contingencies on the electric system.[12] The ISO used power flow modeling as the basis for its recommendations. The ISO's recommendations for the amount of local capacity required to ensure that there is sufficient capacity to keep the lights on at all times are based on load circumstances that are projected by the CEC to occur once in 10 years,[13] and the assumption that the two largest generation or transmission failures occur nearly simultaneously in a local area.

In the previous Rulemaking (R.10-05-006), Commission staff provided the ISO with four scenarios consistent with the 33% renewables portfolio standard[14] (RPS).[15] These scenarios provided information for models tested by the ISO in

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10 Exhibit ISO-1 (Sparks) at 17.

11 Exhibit ISO-1 (Sparks) at 3.

12 Exhibit ISO-1 (Sparks) at 3.

13 Exhibit ISO-1 (Sparks) at 16.

14 *See* Pub. Util. Code §§ 399.11-399.31.

15 The four scenarios are: 1) Trajectory, or the current procurement path; 2) Environmentally-constrained, which focused on reducing land-use impacts; 3) the ISO Base Case, which was a modified version of the CPUC's cost-constrained case wherein cost was the primary consideration; and 4) the time-constrained case, which focused on attaining 33% renewables as quickly as possible.

that proceeding, based on analysis developed in the Commission's RPS proceeding. Due to the settlement adopted in D.12-04-046, such models were not used as the basis for a Commission decision, but these models remain available for use in this proceeding.

In opening testimony, ISO witnesses Rothleder and Sparks describe how in this proceeding they again modeled a number of possible outcomes for the ISO based on the same RPS portfolios. An important part of the modeling was the use of demand forecasts provided by the CEC in its 2010 Integrated Energy Policy Report (IEPR), which used 2009 demand forecast data. Rothleder describes certain modeling changes that led to different results from those produced in R.10-05-006.[16]

The ISO performed a local capacity technical study that "determined the minimum amount of resources within a local capacity area needed to address reliability concerns following the occurrence of various contingencies on the electric system."[17] While the ISO has performed annual short-term (one year out) local capacity studies for a number of years that are used in the Commission's RA proceedings, here the ISO performed a local capacity study that looked at a 10-year planning horizon.[18] This is the first time the ISO has performed this 10-year study.[19]

The ISO performed its studies assuming that generation to meet LCR needs stemming from the assumed retirement of OTC plants would be met via

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[16] Exhibit ISO-4 (Rothleder) at 5-6.

[17] Exhibit ISO-1 (Sparks) at 3.

[18] Exhibit ISO-1 (Sparks) at 5.

[19] Reporter's Transcript (RT) 117.

repowering or replacement in the same locations as the OTC plants.[20] The ISO provided a range of forecasts for each RPS portfolio. The lower end of the range for the four RPS scenarios corresponds to the amount of generation needed if it were located at existing OTC sites that are the most effective at mitigating the identified transmission constraint. The higher end of the range corresponds to the amount of generation needed if it were located at existing OTC sites that are the least effective at mitigating the identified transmission constraint.[21] In the various studies, the ISO found an LCR need of at least 1870 MW for the most effective sites, and up to 3896 MW for less effective sites in the LA basin local area served by SCE. Specifically, the LCR need would be in the Western LA portion of the LA basin local area (a transmission-constrained sub-area of the LA basin).

Several parties challenged the ISO's methodology, as discussed herein. The ISO maintains that no party presented a valid alternative to the ISO's methodology, which it describes as "a deterministic approach based on Northern American Electric Reliability Council/Western Electricity Coordinating Council planning criteria and ISO tariff requirements."[22]

No capacity from demand response[23] 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

[20] Exhibit ISO-1 (Sparks) at 2.

[21] Exhibit ISO-1 (Sparks) at 6.

[22] ISO Opening Brief at 2.

[23] There appears to be price-responsive demand response built into the CEC demand forecast, but not other demand response programs.

characteristics and response to that of a dispatchable generator." The ISO claims "demand response does not have these characteristics at this time."[24]

Nor does the ISO include any demand reduction for uncommitted energy efficiency or uncommitted combined heat and power (CHP) in its forecasts.[25] Uncommitted energy efficiency and uncommitted CHP are potentially viable energy efficiency programs or CHP installations not already included in the 2009 CEC demand forecast, regardless of actions taken after that forecast. The ISO contends that it has "no basis for expecting that uncommitted energy efficiency and uncommitted CHP generation can be counted upon for meeting local reliability needs beyond the committed programs that were included in the CEC's officially adopted demand forecast."[26]

Table 2 shows the various outcomes of the ISO studies.

[24] Exhibit CEJA x ISO-1 at 3.

[25] These resources are termed either "incremental" or "uncommitted." Either term refers to resources beyond the amounts embedded in the CEC's demand forecast.

[26] Exhibit ISO-1 (Sparks) at 15.

TABLE 2

Summary of ISO Studies by RPS Portfolio

Local Area	Local Area Requirements (MW)				Replacement OTC Generation Need (MW)			
	Trajectory	Environmentally Constrained	ISO Base Case	Time Constrained	Trajectory	Environmentally Constrained	ISO Base Case	Time Constrained
LA Basin (this area includes sub-area below)	10,743	11,246	11,010	12,165	2,370 – 3,741	1,870 – 2,884	2,424 – 3,834	2,460 – 3,896
Western LA Basin (sub-Area of the larger LA Basin)	7,797	7,564	7,517	7,397				
Big Creek/Ventura (BC/V) Area	2,371	2,604	2,438	2,653	(Need is for Moorpark only, a sub-area of the Big Creek/Ventura Local area)			
					430	430	430	430

In each of the four RPS scenarios, the ISO model included assumptions of distributed generation MW, and non-distributed generation MW for 2021; all scenarios assumed the same demand forecasts from the CEC. Tables 3 - 6 show the ISO's distributed generation and non-distributed generation assumptions for each scenario.[27]

[27] Exhibit ISO-1 (Sparks) at 7-9.

TABLE 3

Portfolios	Area	Local Area Reqm't Non-D.G. (MW)	Local Area Reqm't D.G. (MW)	Local Area Reqm't Total (MW)	Replacement OTC Units Needed?	Constraint	Contingency
Trajectory	Overall LA Basin	12,961	339	13,300	Yes	Mira Loma West 500/230 Bank #1 (24-Hr rating)	Chino-Mira Loma East #3 230 kV line + Mira Loma West 500/230 kV Bank #2
		10,404	339	10,743	Yes	Eagle Rock-Sylmar S 230 kV line	Sylmar S-Gould 230 kV line + Lugo-Victorville 500 kV line
	Western	7,529	268	7,797	Yes	Serrano-Villa PK #1	Serrano-Lewis #1 / Serrano-Villa PK #2
	Ellis	225	59	284	Yes	Voltage Collapse	Barre-Ellis 230 kV line + SONGS - Santiago #1 and #2 230 kV lines
	El Nido	614	5	619	No	La Fresa-Hinson 230 kV line	La Fresa-Redondo #1 and #2 230 kV lines

TABLE 4

Portfolios	Area	Local Area Reqm't Non-D.G. (MW)	Local Area Reqm't D.G. (MW)	Local Area Reqm't Total (MW)	Replacement OTC Units Needed?	Constraint	Contingency
Environmentally Constrained	Overall LA Basin	11,048	1,519	12,567	Yes	Mira Loma West 500/230 bank #1 (24-Hr rating)	Chino-Mira Loma East #3 23 0kV line + Mira Loma West 500/230 kV bank #2
		9,727	1,519	11,246	Yes	Eagle Rock-Sylmar S 230 kV line	Sylmar S - Gould 230 kV line + Lugo - Victorville 500 kV line
	Western	6,695	869	7,584	Yes	Serrano- Villa PK #1	Serrano-Lewis #1 / Serrano-Villa PK #2
	Ellis	225	124	349	Yes	Voltage Collapse	Barre-Ellis 230kV Line + SONGS - Santiago #1 and #2 230 kV lines
	El Nido	494	91	585	No	La Fresa-Hinson 230 kV line	La Fresa-Redondo #1 and #2 230 kV lines

TABLE 5

Portfolios	Area	Local Area Reqm't			Replacement OTC Units Needed?	Constraint	Contingency
		Non-D.G. (MW)	D.G. (MW)	Total (MW)			
Base	Overall LA Basin	12,659	271	12,930	Yes	Mira Loma West 500/230 Bank #1 (24-Hr rating)	Chino-Mira Loma East #3 230 kV line + Mira Loma West 500/230 kV bank #2
		10,739	271	11,010	Yes	Eagle Rock-Sylmar S 230 kV line	Sylmar S-Gould 230kV line + Lugo-Victorville 500 kV line
	Western	7,325	192	7,517	Yes	Serrano-Villa PK #1	Serrano - Lewis #1 / Serrano - Villa PK #2
	Ellis	225	39	264	Yes	Voltage Collapse	Barre-Ellis 230kV Line + SONGS-Santiago #1 and #2 230 kV lines
	El Nido	544	94	568	No	La Fresa-Hinson 230 kV line	La Fresa-Redondo #1 and #2 230 kV lines

TABLE 6

Portfolios	Area	Local Area Reqm't			Replacement OTC Units Needed?	Constraint	Contingency
		Non-D.G. (MW)	D.G. (MW)	Total (MW)			
Time-Constrained	Overall LA Basin	12,677	687	13,364	Yes	Mira Loma West 500/230 bank #1 (24-Hr rating)	Chino - Mira Loma East #3 230 kV line + Mira Loma West 500/230 kV bank #2
		11,478	687	12,165	Yes	Eagle Rock-Sylmar S 230 kV Line	Sylmar S-Gould 230 kV line + Lugo-Victorville 500kV line
	Western	6,954	443	7,397	Yes	Serrano-Villa PK #1	Serrano-Lewis #1 / Serrano-Villa PK #2
	Ellis	225	61	286	Yes	Voltage Collapse	Barre - Ellis 230 kV line + SONGS-Santiago #1 and #2 230 kV lines
	El Nido	589	31	620	No	La Fresa-Hinson 230 kV line	La Fresa-Redondo #1 and #2 230 kV lines

The ISO recommendation is based on the Trajectory scenario because "the Trajectory scenario studied in the OTC studies is the scenario most aligned with commercial interest."[28] The ISO also believes this scenario best reflects future

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[28] Exhibit ISO-1 (Sparks) at 17.

load growth and renewable generation development.[29] The Trajectory scenario forecasts a need for 2370 MW in the LA basin local area, which Sparks rounds up to 2400 MW.[30] This forecast includes a specific need for 225 MW in the Ellis sub-area.

In supplemental testimony, Sparks describes a sensitivity analysis performed at the request of this Commission, the CEC and the California Air Resources Board (CARB), to study a variation on the Environmentally Constrained portfolio. As part of the sensitivity analysis, demand reduction from 1950 MW of uncommitted energy efficiency and 201 MW of additional CHP was included in the model,[31] as provided by the three state agencies and adjusted for the LA basin local area (as part of 2461 MW of uncommitted energy efficiency and 209 MW of uncommitted CHP for the entire SCE territory).[32] For the Western LA basin sub-area, 1121 MW of uncommitted energy efficiency was included in this analysis, and 180 MW of CHP.[33]

According to this testimony, the results of this sensitivity analysis show a need of 1042 MW needed in the Western LA section of the LA basin local area for 2021 for effective sites, with the range reflecting the same effectiveness considerations as described above.[34] This compares to 1870 MW for effectives sites for 2021 in the Environmentally Constrained scenario in Table 2 herein. The

[29] ISO Opening Brief at 3.

[30] RT 197-198.

[31] Exhibit ISO-9 at (Table 3.4-1).

[32] Exhibit ISO-2 (Sparks) at 2-3.

[33] RT 137-143; Exhibit CEJA x ISO-1 at 2-3.

[34] Exhibit ISO-2 (Sparks) at Table 2.

sensitivity analysis also models the Del Amo-Ellis 230 kilovolt line loop-in project in service, based on updated information in the ISO's supplemental testimony that the ISO Board has now approved this project for 2012. This project eliminates the need for local generation in the Ellis sub-area in this scenario.[35]

The ISO does not recommend relying upon its sensitivity analysis to make a determination as to local area needs in this proceeding. Sparks testified that the ISO does not believe it is prudent to rely on uncommitted resources (such as uncommitted energy efficiency and CHP) for assessing future local needs. Further, Sparks testified that "deliberately conservative forecasts must be employed in the assessment of reliability requirements for capacity in constrained areas since the consequences of being marginally short versus marginally long are asymmetric. A marginal shortage means the loss of firm load, which puts public safety and the economy in jeopardy, whereas a marginal surplus has only a marginal cost implication."[36] Further, Sparks testified that there is "uncertainty" concerning both uncommitted energy efficiency and incremental CHP which makes it imprudent to include these potential resources in the ISO forecasts.[37]

Sparks testified that it is necessary to begin the procurement process for 2021 local capacity needs in 2013 "to ensure we don't forgo the best options, and also to make sure that the options that are available are actually feasible."[38]

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35 Exhibit ISO-2 (Sparks) at 2-3.

36 Exhibit ISO-2 (Sparks) at 3-4.

37 Exhibit ISO-2 (Sparks) at 5-6.

38 RT 199.

3.2. SCE Position

SCE generally agrees with the ISO's analysis identifying a 2021 need for up to 2370 MW of existing LCR generation in the LA basin local area to remain in service or be replaced with similarly located generation (also known as, or up to 3741 MW if new generation cannot be placed at the most effective sites in the local area.[39] SCE seeks authority to start a process in 2013 to enter into contracts for between zero MW and 3741 MW in the LA basin local area.

SCE seeks flexibility in conducting any LCR procurement that is needed. In general, SCE would prefer not to procure resources to meet system needs and to make long-term commitments that would subsequently be rendered less valuable by changed circumstances.[40] SCE "prefers procurement of new LCR generation through a new multi-year forward procurement auction, such as a capacity market or a new generation auction administered by the CAISO" but acknowledges that such a mechanism is not currently available.[41]

Due to uncertainty in forecasts, SCE describes input assumptions in the ISO models that may change based on new information, and which could lead to a higher or lower need for LCR resources than the ISO identified. These include changes to the reliability planning standards, demand forecast, resource scenarios, LCR generation sites, and transmission options.[42] SCE witness Minick testified that another variable in determining long-term LCR needs is accurate

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39 Exhibit SCE-1 (Cushnie/Silsbee/Minick) at 1, 3-5. SCE uses a slightly different definition of "effective" and "less effective" sites than the ISO.

40 Exhibit SCE-1 (Cushnie) at 2.

41 Exhibit SCE-1 (Cushnie) at 1.

42 Exhibit SCE-1 (Minick/Cabbell) at 5-9.

identification of when the OTC plants are expected to close. He points to the potential for extensions of SWRCB deadlines and other changes surrounding OTC regulations as uncertainties in determining need.[43]

Minick also testified that the ISO did not recognize the potential for increased distributed generation, assumptions for uncommitted energy efficiency or increased localized generation, all of which would lower the load on the transmission system.[44] In reply testimony, SCE cites concerns raised by many parties about the ISO's assumptions regarding the availability and use of preferred resources, agreeing with claims by parties that higher levels of preferred resources than forecasted by the ISO will reduce or eliminate the need for new LCR generation in SCE territory.[45]

Despite these uncertainties, SCE witness Silsbee testified that at least some new generation procurement needs to occur to meet LCRs in the LA basin local area. He points to difficulties in constructing new generation in the LA Basin local area, which mean that it might take 7 to 9 years to develop new replacement generation. While there are uncertainties about the dates when OTC plants will cease to operate, there are also uncertainties around the lead time for generation permitting and construction. Therefore, Silsbee testified that there is a need to start initial procurement processes soon; for example, with a Purchased Power Agreement (PPA) entered into and approved by the Commission in 2013, it would potentially take until 2020 or longer for the plant to become operational.[46]

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[43] Exhibit SCE-1 (Minick) at 10.

[44] Exhibit SCE-1 (Minick) at 7.

[45] Exhibit SCE-2 (Silsbee) at 4.

[46] Exhibit SCE-1 (Silsbee) at 16-17.

3.3. DRA Position

DRA recommends the Commission defer a decision on SCE's LCR procurement, in order to allow the Commission to take into account final adopted planning standards in Track 2 of this proceeding that relate to distributed generation standards. DRA also recommends a transmission study to determine if there is further potential to increase imports into constrained areas, and ways to upgrade current transmission facilities. If the Commission authorizes SCE to procure LCR resources, DRA recommends authorization of no more than 169 MW for the LA basin local area for 2021 and no more than 278 MW for this area for 2022.[47]

DRA witness Fagan testified that "the risk of not procuring now is minimal if not zero," and that there is not a technical reliability risk in waiting another two years to make the LCR determination.[48] DRA's concern is that the Commission could authorize procurement of fossil-fuel plants now, when preferred resources may materialize soon which would obviate the need for some fossil fuel resources. Alternatively, DRA recommends that there be an opportunity to revise the LCR need determinations after 2012 planning assumptions are finalized.[49]

DRA has significant concerns about the ISO models for LCR needs. Fagan testified:

> …the CAISO's modeling analyses overestimate the range of deficiency of resources needed to meet 2021 local capacity

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47 Exhibit DRA-6 (Fagan) at 4.

48 RT 924.

49 Exhibit DRA-3 (Spencer) at 12.

> requirements in the LA basin…primarily by either excluding or minimizing the effect that preferred demand side resources, including uncommitted energy efficiency and demand response, can have on projected peak load in these areas by 2021."[50]

Fagan calculates that LCR needs are lowered by more than 40% from the ISO's estimates of 1870 to 2664 MW in the Environmentally Constrained scenario (*see* Table 2) to only 828 to 1207 MW when the additional resources are included in the Environmentally Constrained scenario sensitivity analysis (*see* Table 3).[51]

Fagan testified that the ISO's primary modeling estimates are too high primarily because they exclude all uncommitted energy efficiency and all demand response resources. He believes these resources will be available and should be considered when planning for future year procurement needs.[52] Fagan recommends reducing the ISO forecast by 957 MW of uncommitted energy efficiency and 1550 MW of demand response.[53] Fagan acknowledges that these figures are part of a load and resources table, which is a simpler tool than the ISO's power flow model, and does not consider sub-areas; nevertheless, he contends that DRA's method is appropriate for a procurement proceeding.

DRA witness Spencer testified that the ISO has not properly accounted for the amount of preferred resources (including demand response, energy efficiency and renewable resources) expected to be available to reduce load or

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[50] Exhibit DRA-1 (Fagan) at 2-3.

[51] Exhibit DRA-1 (Fagan) at 2-3, 12-20. There are some methodological differences which cause a variation between DRA's figures and the ISO's figures.

[52] Exhibit DRA-1 (Fagan) at 17.

[53] Exhibit DRA-1 (Fagan) at 18, Table RF-2.

meet electricity demand. He maintains that "failure to adequately account for such resources increases the risk of over-procurement,"[54] including underutilized assets and "crowding out" of preferred resources. Further, over-procurement poses the risk of additional expenses for ratepayers.[55] In other words, ratepayers would pay to reduce load and increase supply, but would then (under the ISO recommendation) also be required to pay for additional supply as if the first set of funded initiatives did not exist.

Spencer also contends State policy goals should be given weight when considering the ISO 2021 local capacity needs recommendations. Specifically, California Governor Brown recently called for the development of 12,000 MW of distributed generation by 2020.[56] While the ISO recommendation of the Trajectory scenario includes 339 MW of distributed generation for the LA basin local area, it also modeled (but did not recommend) the Environmentally Constrained scenario with 1519 MW of distributed generation. DRA supports using the Environmentally Constrained scenario because DRA contends it is in line with California's commitment to distributed generation goals.[57]

3.4. TURN Position

TURN recommends that the Commission authorize procurement sufficient to satisfy 2/3 of the LCR needs sought by the ISO, due to problems with the ISO forecasts. Specifically TURN witness Woodruff contends that the ISO forecasts are "moving targets" that can vary significantly with each new iteration of the

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[54] Exhibit DRA-3 (Spencer) at 1.

[55] Exhibit DRA-3 (Spencer) at 3.

[56] Governor Jerry Brown, Clean Energy Jobs Plan at 3; June 2010.

[57] Exhibit DRA-3 (Spencer) at 8-9.

study.[58] TURN contends that both over-procurement and under-procurement would be costly, but that the ISO ignores the potential costs to ratepayers and focuses only on the "extremely low risk of criteria violations that could potentially result from significant shortage under extraordinarily stressed system conditions."[59]

TURN recommends that the Commission task SCE with procurement of any new local resources authorized in this docket, as the only practical option. TURN recommends that the Commission adopt one or more mechanisms to mitigate potential market power issues and other LCR procurement challenges. Possible mitigations measures include:

- Holding RFPs to seek the most competitive replacements for OTC resources, even in sub-areas in which there are currently no known alternatives to an OTC unit. Such RFPs should solicit both conventional generation and non-fossil alternatives.
- Providing minimum and maximum procurement targets to ensure truly needed amounts are procured but prevent procurement of capacity that will not necessarily be needed.
- Implementing some type of "circuit breaker" mechanism to allow procurement of lower amounts of capacity should prices of one or more bids greatly exceed a reasonable cost.
- Providing procurement in the most logistically challenging areas first, such as the Ellis and Moorpark sub-areas.[60]

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[58] Exhibit TURN-1 (Woodruff) at 7-9.

[59] TURN Opening Brief at 6.

[60] Exhibit TURN-1 (Woodruff) at 2-3.

3.5. Environmental Parties' Positions

CEJA, NRDC, Sierra Club and WEM all contend that the ISO local capacity methodology should not have excluded significant amounts of uncommitted energy efficiency, CHP, demand response and energy storage. CEJA claims that "CAISO's results are inherently conservative and call for greater MW than will actually be needed."[61] NRDC claims "the amount of efficiency included in the CAISO's assessment of local capacity needs is unreasonably low because it excludes all savings from future energy efficiency policies, as well as some that were recently adopted."[62] Sierra Club contends that the ISO "uses worst case, unrealistic assumptions," such as modeling for outages which have not occurred in the last 10 years.[63] WEM argues that omitting certain categories of uncommitted energy efficiency "will lead to major forecast errors."[64]

Vote Solar recommends the Commission make a finding of LCR need for the total of the LA basin local area and the Big Creek/Ventura local area of between 800 MW and 1700 MW, depending on location.[65] However, Vote Solar recommends authorizing SCE to procure some of the identified LCR needs via gas-fired plants (preferably in the most efficient locations), but to wait a few years to see how much uncommitted energy efficiency, demand response and

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[61] Exhibit CEJA-1 (Powers) at 4.

[62] Exhibit NRDC-1 (Martinez) at 1.

[63] Sierra Club Opening Brief at 5-6.

[64] Exhibit WEM-1 (George) at 10.

[65] Vote Solar Opening Brief at 2, 4-5.

distributed photovoltaic installations will be available for delivery to reduce LCR needs by 2020.[66]

CEJA's analysis foresees additional resources, including additional transmission fixes, which can lower the LCR need in the LA basin local area for 2021. CEJA contends that these added resources tend to be available when most needed and are distributed geographically. CEJA claims that the ISO's failure to consider or include uncommitted energy efficiency, demand response, incremental CHP and all available distributed generation is unreasonable. CEJA concludes that, after including these additional resources, the actual LCR need under each of the four RPS scenarios is "likely zero."[67] Sierra Club also recommends a finding of zero LCR need for the LA basin local area.[68]

CEERT contends that the ISO assumed higher customer loads than adopted as State policy, inconsistent with the Loading Order. While CEERT is concerned that the ISO's forecasts are based upon relatively rare contingencies, CEERT does recommend finding procurement of no more than 1800 MW for LCR needs in this proceeding.[69] However, CEERT wants the Commission to identify eligibility requirements and performance metrics for preferred resources that can meet LCR needs, before authorizing LCR procurement.[70] CEERT would

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[66] Exhibit Vote Solar-1 (Gimon) at 4-5.

[67] Exhibit CEJA-3 (May) at 2-3.

[68] Sierra Club Opening Brief at 19.

[69] CEERT Opening Brief at 30.

[70] CEERT Opening Brief at 4-5.

allow non-traditional resources (those other than gas-fired resources) to submit bids in any solicitation to fill this need, consistent with the Loading Order.[71]

3.6. Other Party Positions

PG&E recommends that the LCR need determination should be based on the ISO study, because the ISO uses a conservative approach without modification for uncertain resource availability. PG&E also recommends that the Commission not establish any preferred resources set-asides in this proceeding.[72] SDG&E recommends that the ISO's LCR determinations should be accorded considerable weight by the Commission. SDG&E endorses SCE's position that SCE be authorized to procure up to the LCR amounts recommended by the ISO, with review by the Commission of SCE proposed contracts.[73]

CLECA contends that new generation can be operational in less than 7 to 9 years in some circumstances, such as by getting plants to the point of construction but only paying for an option to build if necessary. CLECA suggests the Commission could authorize development contracts that include permitting and site development but do not include construction, effectively creating an option for expedited development of new generation if and when it is needed.[74] CLECA also contends that the ISO, due to its obligations with respect to grid reliability, recommends over-procurement compared to what are required under NERC/WECC standards, leading to excessive ratepayer costs.[75]

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[71] Exhibit CEERT-1 (Caldwell) at II-3 - II-4.

[72] PG&E Opening Brief at 4-9.

[73] SDG&E Opening Brief at 3-11.

[74] CLECA Opening Brief, p. 28.

[75] CLECA Opening Brief, pp. 12-19.

IEP contends there is a need for some form of replacement capacity for the potential retirement of at least some OTC units, and that IOUs should procure LCR resources through competitive solicitations, or cost-of-service contracts.[76] IEP recommends a "somewhat more conservative approach" to determining LCR needs in order to ensure that firm load curtailments do not occur.[77] IEP proposes an "Incremental Need" calculation to set procurement targets; the Commission would authorize IOUs to procure resources at the level recommended by the ISO, but acknowledge that other resources might become committed in the future.[78]

EnerNOC criticizes the ISO for leaving various preferred resources out of its forecasts, focusing on the exclusion of demand response resources.[79] EnerNOC recommends the Commission find an LCR need for the LA basin local area of 2400 MW minus a MW amount reflective of expected growth of preferred resources in the local area, as an interim target. EnerNOC recommends the Commission reconsider the level of LCR need in the next long-term procurement proceeding, expected in 2014.[80]

Calpine recommends that any procurement authorized in this proceeding to satisfy LCR needs not be granted until system needs have also been determined in Phase 2 of this proceeding. Calpine contends that such an approach will put the IOUs in a better position to identify the least cost/best fit

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[76] Exhibit IEP-1 (Monsen) at 5-11.

[77] Exhibit IEP-1 (Monsen) at 20-21.

[78] Exhibit IEP-1 (Monsen) at 5-11.

[79] EnerNOC Opening Brief at 4-15.

[80] EnerNOC Opening Brief at 15.

mix of resource options to satisfy both local and system needs.[81] Calpine also recommends adopting procurement rules to ensure all viable technologies, resources and solutions are considered by the IOUs to satisfy local and system reliability needs. This would include gas-fired plants, preferred resources and transmission alternatives and upgrades.[82]

AES calculates a need for approximately 2300 MW at certain OTC locations in the LA Basin local area. Therefore, AES finds the ISO recommendation for approximately 2400 MW at effective locations to be consistent with its own analysis.[83]

CCC disagrees with the ISO that uncommitted energy efficiency and CHP should be excluded from LCR forecast models. CCC argues that the ISO's reliance on the CEC's IEPR misses more recent developments with regard to CHP. Specifically, CCC points to Commission approval of the "QF/CHP Settlement Agreement" in D.10-12-035 which has led to IOUs conducting their initial Request for Offers (RFOs) to procure 2000 MW of CHP capacity.[84] CCC also cites to more recent CEC efforts to update its projections for future CHP development in California.[85]

ANR endorses the ISO's Trajectory scenario estimate for the LA basin local area, but has strong reservations about the future availability of SONGS and a 600 MW transmission transfer. ANR contends the risk of over-capacity is smaller

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81 Exhibit Calpine-1 (Barmack) at 1, 4.

82 Exhibit Calpine-1 (Barmack) at 5.

83 Exhibit AES-1 (Ballouz) at 1-2.

84 Exhibit CCC-1 (Beach) at 6-7.

85 Exhibit CCC-1 (Beach) at 7-8.

than the risk of under-capacity.[86] ANR recommends that Track 1 of this proceeding be continued after the Commission decision issues for the purpose of adjusting the determined LCR need, in order to take into account new information contained in the upcoming ISO 2012-2013 Transmission Plan.[87]

4. Long-Term Local Capacity Requirements for LA Basin Local Area – Discussion

4.1. Statutory Guidance

The Legislature has stated its policy goals relating to reliability, reasonableness of rates, and a commitment to a clean environment in the "Reliable Electric Service Investments Act," codified as § 399(b). This statute protects these divergent interests by ensuring investments in the integrity of the grid, in a sizeable and well trained utility workforce, in cost-effective energy efficiency improvements, in a sustainable supply of renewable energy, and in research and development that will advance the public interest.

The Commission is also bound by the RA Requirements in § 380. Section 380(c) states:

> Each load-serving entity shall maintain physical generating capacity adequate to meet its load requirements, including, but not limited to, peak demand and planning and operating reserves. The generating capacity shall be deliverable to locations and at times as may be necessary to provide reliable electric service.

The implementation of RA serves to ensure system reliability as well as siting and construction of new resources. Section 380 requires LSEs to maintain 100% of forecast load available as well as a 15% reserve. LSEs are also required

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86 ANR Opening Brief at 21.

87 ANR Opening Brief at 22.

to demonstrate to the Commission that sufficient Local RA resources have been procured in order to meet the needs of transmission constrained Local Areas.

A primary responsibility of this Commission is to ensure reliability in the electrical system. It would neither be prudent nor responsible to allow the system to fail and the lights to go out when we reasonably could have avoided such deleterious outcomes. Similarly, the primary mission of the ISO is to ensure reliability in the California electrical grid. Section 345 states:

> The Independent System Operator shall ensure efficient use and reliable operation of the transmission grid consistent with achievement of planning and operating reserve criteria no less stringent than those established by the Western Electricity Coordinating Council and the North American Electric Reliability Council.

A significant difference between the ISO's reliability mission and the Commission's reliability emphasis is that the Commission must balance its reliability mandate with other statutory and policy considerations. Primarily, these considerations are reasonableness of rates and a commitment to a clean environment. These considerations stem from both statute and Commission policy consistent with statute.

Regarding reasonableness of rates, § 451 states in pertinent part:

> All charges demanded or received by any public utility… shall be just and reasonable. Every unjust or unreasonable charge demanded or received for such product or commodity or service is unlawful.

Further, § 454 states:

> Except as provided in Section 455, no public utility shall change any rate or so alter any classification, contract, practice, or rule as to result in any new rate, except upon a showing before the commission and a finding by the commission that the new rate is justified.

There are a number of statutes which require the Commission to implement procurement-related policies to protect the environment. As a primary example, the Commission's RPS program is established in §§ 399.11-399.31. As discussed in Section 2, the Loading Order was established both in the Energy Action Plan and in statute.

In this decision, we strike a balance among the Commission's three primary statutory directives for ensuring reliability, reasonable rates and a clean environment. We cannot, and will not, sacrifice or ignore any of these imperatives. Nor need we do so; the record in this case supports outcomes which enable us to accomplish all our goals, meet statutory requirements and direct utilities to procure sufficient levels of diverse resources in a timely manner at a reasonable cost so as to ensure reliability. We now turn to the specific details.

4.2. Assumptions

ISO witness Sparks acknowledged that forecasting one year ahead is easier than 10 years out, with the 10-year forecast entailing more uncertainty on many factors.[88] Referring to the sensitivity analysis of the Environmentally Constrained scenario (which includes assumptions of more distributed generation, more uncommitted energy efficiency and more demand response than the Trajectory scenario), Sparks testified that the ISO study methodology "would need to be revisited if we were to actually see these types of changes to the resource supply in the area."[89] Because of the difficulty in assessing forecasts 10 years into the future done for the first time, it is necessary to carefully assess

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[88] RT 79.

[89] RT 81.

the assumptions in such forecasts and to build in a method to revisit the forecasts when more information is available.

Sparks further testified:

> The ISO has no basis for expecting that uncommitted energy efficiency and uncommitted combined heat and power generation can be counted on for meeting local reliability needs beyond the committed programs that were included in the CEC's officially adopted demand forecast."[90]

However, we do have a basis for considering an estimate of such resources in our analysis. We discuss such estimates below.

Sparks claims that "the consequences of being marginally short versus marginally long are asymmetrical" because "a marginal shortage means a loss of firm load, which puts public safety and the economy in jeopardy, whereas a marginal surplus has only a marginal cost implication."[91] DRA disagrees. DRA witness Spencer cites costs reaching over one billion dollars (plus annual maintenance costs) as being very significant and not simply marginal.[92] In addition, there are significant environmental detriments to building and running more fossil-fuel power plants than necessary.

ISO witness Millar agrees that if reliability needs are met through natural gas generation, but more distributed generation occurs than the ISO forecasts, this would increase ratepayer costs (although he contends "that is a consequence

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[90] Exhibit ISO-1 (Sparks) at 15.

[91] Exhibit ISO-2 (Sparks/Millar) at 4; Exhibit DRA-3 (Spencer) at 16, citing Rebuttal Testimony of Robert Sparks on Behalf of the California Independent System Operator Corporation, A.11-05-023, June 4, 2012 at 3.

[92] Exhibit DRA-3 (Spencer) at 16, citing PG&E's pending Oakley power plant Application (A.12-03-026).

of having to move forward in the face of uncertainty.")[93] Presumably, increased ratepayer costs would also occur if more energy efficiency or other resources than in the ISO models came to fruition. On the other hand, as already noted herein, the ISO contends that delaying procurement can result in lost opportunities due to a potential seven to nine year lead time for certain plants to go from proposal to operational.

We agree with the ISO that under-procurement entails significant risks. We also agree with DRA and others that over-procurement entails significant risks. We do not agree with the ISO that one error is necessarily more problematic than the other; neither error is desirable if avoidable. Nor can the consequences of either outcome be easily quantified; neither the ISO nor anyone else has quantified these consequences.[94]

Our intent is to neither authorize over-procurement nor under-procurement. However, the procurement process is of necessity imperfect because it relies on future forecasts. One benefit of a long planning horizon is the opportunity to adjust to the inevitable changes in circumstances. We will balance the potential for lost or limited opportunities to procure certain resources with long lead times against the opportunities to reconsider circumstances in the future.

The ISO used power flow modeling to develop its scenarios to forecast LCR needs. SCE agrees with this approach because it takes into consideration transmission constraints and limitations in specific local areas.[95] DRA proposes

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[93] RT 474.

[94] RT 499-503.

[95] Exhibit SCE-2 (Cabbell) at 16.

using a load and resources table. While DRA's approach has its benefits, there is general agreement that the ISO's modeling is more sophisticated and precise. We find the use of the ISO's power flow modeling to be reasonable for these purposes.

Sparks agreed that the precision of the ISO's power flow simulation is "completely dependent" upon the accuracy of the input assumptions, and that if the input assumptions vary, then the results would vary.[96] Therefore, it is important to consider whether any major assumptions used by the ISO should be revisited.

4.2.1. One-in-Ten Year Load, with Two Major Contingencies

The first question is whether the ISO's general methodology is reasonable. In our RA proceedings, we use ISO forecasts with a one-in-10-year load forecast, with two major contingency outages, to assess LCR needs one year in advance. In this proceeding, the ISO for the first time extended this methodology out to 10 years in advance.

A number of parties question whether the ISO's approach is appropriate. CEERT and others raise the issue of whether we should authorize procurement of up to several thousand MW of capacity based on a rare set of circumstances – essentially (as CEJA puts it) a "scenario that two import pathways to SCE's territory are unavailable on the hottest day in 10 years."[97] ISO witness Sparks testified that this situation in the LA basin local area has never

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[96] RT 167.

[97] CEJA Opening Brief at vii, 6-8.

occurred in the last 10 years.[98] The ISO did not analyze any scenario with only one contingency.

We recognize that the ISO models use assumptions of rare and unusual circumstances, which may never occur. However, this methodology is well-tested in our RA proceedings as a means of procurement of resources for local reliability purposes. As PG&E points out, the Commission must ensure the system will be reliable under a variety of possible future states, including a high load stress condition.[99] While the circumstances underlying the methodology are (hopefully) rare, the consequences of not having sufficient resources in such a rare situation would be extremely serious. We generally will use the ISO methodology for consideration of LCR needs, with the caveats concerning inputs discussed herein.

4.2.2. OTC Plant Compliance Schedule

The next question to consider is whether the OTC plants are likely to retire according to the compliance schedule presented in Table 1 herein. The schedule determined by the SWRCB is beyond our jurisdiction. However, we can consider relevant factors in the record that might influence whether the schedule will hold.

ISO witness Sparks testified that the ISO participates in a SWRCB committee called the Statewide Advisory Committee on Cooling Water Intake Structure (SACCWIS). In that committee, Sparks stated that the ISO "would seek to adjust the [OTC retirement] schedule" if it determines that reliability cannot be

[98] RT 120.

[99] PG&E Opening Brief at 6.

met within the schedule.[100] If the retirement schedule is delayed for one or more plants past 2020, there could be a reduction in the local reliability need for the LA basin local area. In addition, Sparks testified that the continued operation of OTC plants was one possible way to meet local needs.

ISO witness Millar testified that there are a range of mitigation options in lieu of the addition of generation by SCE, if reliability cannot be met. He continued that these options may "fall within our current framework and our current authorities as well as should we be seeking additional authorities in order to advance the necessary reinforcements." For example, continuation of procurement already under ISO contract and consideration of load-shedding are other options. However, he also stated that while "[t]here is no framework to simply delay compliance with once-through cooling" retirement deadlines, working with the SWRCB to consider changing deadlines would be an option (but not "a given").[101]

If the Commission authorizes procurement based on the current OTC plant closure schedule, there could be over-procurement to the detriment of ratepayers and the environment if the plants do not close as scheduled. DRA contends that several OTC plants in the LA basin local area have asked for partial deadline extensions of up to six years.[102] DRA claims that the SACCWIS in March 2012 recommended considering extension deadlines on a unit-by-unit basis.[103] CEJA contends that SWRCB OTC policy does not require any coastal OTC plants to

[100] RT 193 - 194.

[101] RT 447-456.

[102] Exhibit DRA-2 (Siao) at 5.

[103] Exhibit DRA-9.

actually retire, but allows these plants to remain operating should they comply with one of two tracks in the OTC policy (new cooling technologies or unit-by-unit measures to reduce marine impacts). CEJA claims many OTC units will not retire but will comply with one of the two tracks.[104] CLECA points out that delaying implementation of the OTC policy is an option for some limited period of time if it takes a little longer to implement full mitigation of the LCR consequences of this policy or to resolve some of the uncertainties that are currently driving the expected cost of LCR mitigation.[105]

We are aware of some efforts by specific OTC plant owners to comply with one of the SWRCB tracks to avoid retirement. However, there is at this time insufficient evidence that any change to the OTC deadlines in Table 1 will occur. As CLECA suggests, it may be that the ISO will request a delay in the OTC closure schedule in order to ensure ongoing reliability. While we do not anticipate such a delay, if any extensions to OTC closure deadlines do occur, this can be taken into account in future procurement proceedings or in review of a procurement application by SCE. At this time, it is reasonable to accept as a fact that, based on information available today, OTC plants will close as per the SWRCB schedule in Table 1.

4.2.3. Transmission

DRA contends that there are transmission fixes that may be able to offset some of the local capacity needs identified by the ISO. However, DRA acknowledges that it remains unclear whether additional cost-effective

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104 Exhibit CEJA-1 (Powers) at 27-30.

105 CLECA Opening Brief, p. 25.

transmission solutions are available that can reduce LCR need, and recommends further study.[106]

SCE agrees with DRA that the ISO did not consider certain transmission mitigation that could reduce LCR need,[107] but contends that the ISO's transmission infrastructure assumptions are reasonable.[108] SCE witness Cabbell testified that every year SCE evaluates the transmission grid and (with the ISO) looks for feasible and cost-effective transmission fixes.[109] However, she also asserts that there are challenges to reducing the local capacity need through transmission fixes, including the viability of construction of new transmission lines in the LA basin local area, increased need for voltage support for upgraded transmission, and a 7-to-10 year lead time to put in new transmission lines.[110] ISO witness Millar testified that "we have identified the…low-hanging fruit where transmission reinforcement was a viable way to reduce local capacity requirements" and these reinforcements were included in the ISO forecasts.[111]

CEJA contends that the ISO should have assumed in its models a 600 MW transmission load transfer to resolve the most critical contingency for the overall LA basin involving the Mira Loma West transmission line. According to CEJA, this transfer would significantly lower levels of LCR in the LA basin, if

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106 Exhibit DRA-1 (Fagan) at 4-5. Also *see* RT 907-910 and DRA Opening Brief at 24.

107 Exhibit SCE-1 (Cabbell) at 8-9.

108 Exhibit SCE-2 (Cabbell) at 16.

109 RT 778.

110 Exhibit SCE-2 (Cabbell) at 17-18; RT 798.

111 RT 421.

feasible.[112] The ISO states that "it is a reasonable assumption to base the 2021 local area generation on the proposed [600 MW] mitigation." The ISO also states that it has had preliminary discussions with SCE on this matter, but needs to obtain a cost and schedule for such an upgrade from SCE.[113] SCE witness Cabbell testified that SCE has not performed any technical analysis or power flow modeling on this proposal, which would require further investigation with the ISO. However, she understands that this mitigation measure could be useful for reducing the LA basin local area LCR but not necessarily the Western LA basin sub-area LCR.[114]

We find there is no conclusive evidence that any assumptions used by the ISO with regard to transmission capacity and contingencies are not appropriate. It is possible or even likely that there are certain mitigation options for transmission constraints or certain transmission upgrades which were not fully considered by the ISO and which may become feasible. It is also possible that certain transmission fixes may become feasible and cost-effective, including the use of synchronous condensers, static var compensators and shunt capacitors, all of which SCE considers annually.[115] In future procurement proceedings and in SCE's procurement application, we may be able to incorporate new information about transmission upgrades and new transmission capacity.

We find the ISO's transmission assumptions to be reasonable for use in this proceeding in determining LCR procurement authorizations.

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112 Exhibit CEJA-3 (May) at 4-7.

113 Exhibit CEJA-3 (May) at 6 (from ISO response to CEJA request No. 8).

114 RT 782; 828.

115 RT 173; 780-781.

4.2.4. Demand Assumptions

The ISO used the 2009 mid-energy demand case of the Final California Energy Demand Forecast of the CEC for 2010 - 2020, prepared as part of the CEC's 2010 IEPR, as the basis for its demand assumptions in its power flow models.[116] In and of itself, no party disputed that this forecast was reasonable. We agree. However, this is not the end of the analysis. We now consider whether there are elements of demand that should be considered in addition to or as supplements to that forecast.

4.2.4.1. Energy Efficiency

The ISO included in its modeling the amount of energy efficiency included in the CEC 2009 demand forecast (mid-energy forecast). This amount includes a significant amount of energy efficiency stemming from programs approved by the Commission through the IOUs (such as lighting programs and appliance efficiency programs)[117] and statewide programs approved by the CEC (such as building standards). This amount does not include any uncommitted energy efficiency. Several parties recommend adding in some forecast of uncommitted energy efficiency, which would decrease demand and, if located effectively, decrease local capacity needs.

As SCE witness Cushnie notes: "Energy efficiency can't address all of the needs of the electric system."[118] This includes meeting all technical requirements to directly reduce LCR needs. However, energy efficiency does directly reduce

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[116] This forecast was posted on May 30, 2012 on the CEC website.

[117] *See* D.12-11-015 for the most recent Commission-approved energy efficiency programs for IOUs.

[118] RT 688.

electrical demand, which indirectly reduces local capacity requirements. The question before us is whether some amount of uncommitted energy efficiency is certain enough to reduce demand through 2021.

IOU energy efficiency programs are funded on a three-year cycle basis (with occasional one-year extensions.) After the three-year cycle concludes, these resources are not considered committed in the CEC demand forecast analysis used by the ISO. As DRA witness Fagan points out, this does not mean the resources are not available. He testified that, due to the State policy of placing energy efficiency first in the Loading Order, "it is a relatively safe bet that funding will continue and that those resources will show up."[119]

NRDC contends that uncommitted energy efficiency levels in the CEC's 2009 Incremental Impacts Report[120] is what the CEC stated should be subtracted from the its base forecast. The CEC uncommitted energy efficiency forecast from 2009 included all anticipated energy efficiency programs from 2013-2020, all building code improvements between 2006 and 2020 and all appliance standards improvements between 2005 and 2020.[121] NRDC and CEJA list a number of energy efficiency programs which have already been adopted and are already saving energy, but which were excluded from the ISO forecasts because they were categorized as uncommitted.

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[119] RT 904-906.

[120] *Incremental Impacts of Energy Efficiency Policy Initiatives Relative to the 2009 Integrated Energy Policy Report Adopted Demand Forecast, CEC, May 2010. See* excerpts in Exhibit CEJA-2 at 75-77.

[121] Exhibit NRDC-1 (Martinez) at 3-4.

CEJA contends that the CEC's 2009 Incremental Impacts forecast for uncommitted energy efficiency is actually conservative, as it includes a low realization rate for "Big Bold Energy Efficiency Strategies" (BBEES) adopted as goals by this Commission in D.07-10-032 and in our 2008 Energy Efficiency Strategic Plan.[122] One of the BBEES is that all new commercial construction will be zero net energy by 2030.[123] As evidence that the BBEES are becoming more likely to be realized, CEJA points to Governor Brown's Executive Order B-18-12 which calls for 50% of California state government commercial buildings to reach zero net energy by 2025.[124]

ISO witness Millar agreed that the CEC demand forecast from the 2009 IEPR used by the ISO did not include BBEES or other uncommitted energy efficiency programs.[125] Examples of such programs already adopted or already in place include:[126]

- California's 2008 Title 24 Building Code;
- California's 2010 Title 20 Lighting Standard;
- California's 2010 Television Efficiency Standard;
- California's 2012 Title 20 Battery Charge Standard;
- California's 2013 Title 24 Building Code; and

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[122] Exhibit CEJA-1 (Powers) at 5.

[123] The other BBEES are: a) All new residential construction in California will be zero net energy by 2020; b) Heating ventilation and air conditioning will be transformed to ensure that its energy performance is optimal for California's climate; and c) all eligible low-income customers will be given the opportunity to participate in the low income energy efficiency program by 2020.

[124] Exhibit CEJA-1 (Powers) at 3.

[125] RT 445-447.

[126] Exhibit NRDC-1 (Martinez) at 4-5.

- Several Federal standards on appliances such as water heaters and clothes washers.

Energy efficiency is first in the Loading Order set forth in the Energy Action Plan. Our commitment to cost-effective energy efficiency has been consistent, and the resources we have approved for IOU energy efficiency programs have grown considerably over the last several years. In D.09-09-047, we approved approximately $3.2 billion in energy efficiency funding for 2010 through 2012. As required by statute, we fully expect to continue to fund all cost-effective energy efficiency into the foreseeable future. Recently, in D.12-05-014, we adopted 2013-2014 IOU energy efficiency portfolios, with estimates of 576 MW of energy savings statewide and 293 MW in SCE territory specifically.[127] Thus there is good reason to expect that California's commitment to energy efficiency will continue, if not strengthen. The likelihood that stretch energy efficiency goals will be achieved was enhanced by the November 6, 2012 passage of California Proposition 39, which (among other things) provides for $500 million per year in additional energy efficiency funds.

SCE's practice for many years has been to include certain components of uncommitted energy efficiency in doing its own internal load forecasts.[128] The ISO agrees that, to the extent uncommitted resources ultimately develop, they can be helpful in reducing overall net demand.[129] It is entirely consistent to assume that our ongoing energy efficiency efforts will result in continuation of successful programs and development of improved programs. We have no

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[127] D.12-05-015, section 4.5.8. Savings here are from programs, not including standards.

[128] RT 1032.

[129] Exhibit ISO-2 (Sparks/Millar) at 4.

doubt that the California Public Utilities Commission, CEC and federal programs and standards incorporated into uncommitted energy efficiency amounts will occur, as these are already in place.

We find that amounts of uncommitted energy efficiency in programs and standards already approved by this Commission and other agencies, but not yet in the demand forecast used by the ISO, should result in adjustments to demand forecasts for the purpose of authorizing LCR procurement levels.[130] There is a significant amount of uncommitted energy efficiency in such programs and standards that is certain to exist in the future. Many approved actions were included in the 2009 CEC uncommitted energy efficiency forecasts. Not all uncommitted energy efficiency is as certain to occur. For example, the Commission's BBEES are goals that may well materialize – and we intend to actively pursue these goals -- but achievement of these laudable goals is still somewhat speculative at this time. The CEC 2009 forecast of uncommitted energy efficiency properly evaluates the potential savings from uncommitted energy efficiency.

We now turn to the question of how much demand in the LA basin local area should be reduced by uncommitted energy efficiency. NRDC recommends a minimum amount of 2461 MW of uncommitted energy efficiency for the SCE territory.[131] This figure is derived from the Scoping Memo in R.10-05-006[132] (the

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[130] The CEC may wish to consider eliminating the distinction between forecasted energy efficiency and forecasted uncommitted energy efficiency in the future in favor of a single forecast of anticipated levels.

[131] Exhibit NRDC-1 (Martinez) at 6-7.

predecessor to this proceeding and part of the record in this proceeding), and is based on the CEC's analysis of the total amount of energy efficiency that is incremental to its 2009 demand forecast. However, this amount is for all of the SCE territory, not just the LA basin local area. DRA uses the same information as the ISO uses in the Environmentally Constrained Scenario sensitivity analysis, and recommends assuming 2305 MW of uncommitted energy efficiency in the LA basin local area by 2021. CEJA estimates 1934 MW of uncommitted energy efficiency in the LA basin local area by 2021.[133]

There is a difference between using uncommitted energy efficiency levels for projecting future demand levels and using uncommitted energy efficiency levels for forecasting local capacity requirements. Lower demand levels do not reduce LCRs on a one-to-one basis, but must be modeled. In addition, uncommitted energy efficiency may not occur uniformly across the state. Amounts must be allocated or assigned to specific areas to model outcomes. A sophisticated power flow model can show the impacts of different demand levels with accuracy and detail. This is exactly what the ISO did in the Environmentally Constrained scenario sensitivity analysis. For the LA basin local area, the ISO determined that the LCR need for 2021 is 1042 MW in that scenario sensitivity analysis for effective sites, after including the CEC's uncommitted energy efficiency forecasts.

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[132] Assigned Commissioner and Administrative Law Judge's Joint Scoping Memo and Ruling, R.10-05-006 (December 3, 2010), Attachment 1; and Corrections to December 3, 2010 Long-Term Procurement Plans (LTPP) Scoping Memo (February 10, 2011).

[133] Exhibit CEJA-3 (May) at 2.

The ISO determination of 1042 MW in the sensitivity analysis is 828 MW below its determination for the Environmentally Constrained scenario (*See* Table 2). The only difference between these scenarios is modeling of uncommitted energy efficiency and CHP resources. We can impute that a similar 828 MW reduction in LCR needs would occur in other scenarios.

We find that the ISO's Environmentally Constrained scenario sensitivity analysis includes a reasonable level of uncommitted energy efficiency for the LA basin local area. We will consider this level as part of our authorization of what level of LCR need SCE is authorized to seek.

4.2.4.2. Demand Response

The ISO did not include any demand response in its forecast beyond the amount embedded in the CEC IEPR forecast.[134] As with energy efficiency, there are various demand response programs that already exist, but were not included in the ISO models. There are also a number of demand response programs under development. Demand response is equal with energy efficiency at the top of the Loading Order in the Energy Action Plan.

CEJA contends the ISO should have included more demand response in its analysis estimating that up to 2224 MW of demand response resources may be available in the LA basin.[135] CEJA cites D.12-04-045 stating "demand response will be an increasingly valuable resource as we pursue future policy challenges."[136] CEJA lists a number of recent developments at the Commission

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[134] SCE witness Silsbee testified that price-responsive demand may be embedded in the CEC demand forecast. RT 1040.

[135] Exhibit CEJA-1 (Powers) at 6 – 14; Exhibit CEJA-3 (May) at 2.

[136] D.12-04-045 at 77.

and the ISO to facilitate integration of demand resources into ISO electricity markets. In its Opening Brief, CEJA estimates that 1064 MW of demand response should be considered in the LCR calculation.[137]

EnerNOC claims that SCE has identified an opportunity to nearly double its existing demand response portfolio by 2017 as a result of such technologies as SCE's Smart Grid Deployment Plan by adding an additional 1500 MW of demand response potential, to approximately 3000 MW. EnerNOC contends that at least some of this should be assumed to be in the LA Basin and have capability of reducing that area's LCR need.[138]

DRA presented evidence that SCE's most recent load impact report predicts 942 MW of demand response for 2020 for the Western LA Basin.[139] This forecast does not identify a level of locally dispatchable demand response resources nor does it evaluate the effectiveness of demand response resources in reducing LCR needs. SCE witness Silsbee testified that at least 549 MW of demand response is currently available in the Western LA Basin, with 102 MW in the most effective locations.[140] It is unclear how much of these resources are locally dispatchable.

EnerNOC objects to the ISO's LCR need assessment for its "failure to include or adequately consider demand response resources in (its) need assessment, either in terms of meeting or reducing its need."[141] EnerNOC

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[137] CEJA Opening Brief, p. 35.

[138] Exhibit EnerNOC-1 (Tierney-Lloyd) at II-8.

[139] Exhibit DRA-6 (Fagan), p. 8 (Table RF-1)

[140] RT 1079, referencing Exhibit CEJA x SCE 03.

[141] EnerNOC Opening Brief at 16.

witness Tierney-Lloyd testified with regard to demand resources that "the filter for evaluating preferred resources must not only be what is feasible and reliable by today's standards; but, what is likely to be available during the planning window."[142]

We agree that demand response programs are important resources in the California electricity system. However, there are differences between demand response and energy efficiency. The ISO contends that demand response programs should not be counted for local reliability purposes because there are limitations on the use of these programs, customers are not required to shed load when called upon, demand response programs generally do not have the necessary characteristics (such as voltage support) of supply-side resources,[143] and the effects of demand response programs may not materialize at the times and in the locations needed.[144]

ISO witness Sparks allows that demand response "could be used to reduce the replacement OTC needs if the demand response is in electrically equivalent locations and if they materialize and are determined to be feasible for mitigation."[145] ISO witness Millar also testified that it may be possible to develop specific demand response programs which would be able to count for reliability purposes, possibly including programs targeted to specific local areas,[146] or to

[142] Exhibit EnerNOC-3 (Tierney-Lloyd) at III-2.

[143] Exhibit ISO-4 (Rothleder) at 9; RT 287.

[144] RT 350 - 352.

[145] Exhibit ISO-1 (Sparks) at 15; RT 204-205.

[146] RT 352-355.

shave peak load (which would reduce the load forecast).[147] However, there are no demand response programs at this time which the ISO believes meet reliability criteria.

In D.11-10-003 in the RA proceeding, we adopted protocols for counting demand response resources for reliability purposes. In that decision, we required that, effective in 2013, demand response resources must be dispatchable locally to count as RA resources. Millar contends that, even with this requirement, there is "no basis yet to have…sufficient comfort that (demand response resources) will actually reduce our local capacity needs" because it is unclear that there will be any locally dispatchable demand response programs.[148]

In other proceedings, we are moving forward to promote cost-effective demand response and to integrate demand response programs as reliability resources. SCE acknowledges the potential of demand response resources to address the transmission contingencies in the ISO's analysis.[149] SCE witness Silsbee testified that he sees "no reason" why a small amount of demand response which now counts for local RA requirements cannot be counted toward meeting LCR needs (although there may be limits to the ability of demand response to meet LCR needs).[150] However, SCE recommends additional work regarding the economics and viability of demand response programs for reliability purposes, and for meeting the needs of the grid and fitting in with the

[147] RT 423-425.

[148] RT 433-434.

[149] Exhibit SCE-2 (Silsbee) at 12-13.

[150] RT 1044-1045.

transmission system. Therefore, SCE recommends more study to see if such programs can reduce the LCR need.[151]

We fully expect that innovative demand response programs will continue to develop, including those that possess characteristics that are consistent with ISO local reliability criteria. In R.10-05-006, the predecessor to the proceeding, the Scoping Memo (Appendix 1 at 60) estimated 2842 MW of demand response resources would be available in the SCE territory in 2020. In D.12-04-045, our recent demand response decision, we stated:

> The California Clean Energy Future plan expressly acknowledges that in addition to its historic role as an emergency and peak demand management tool, DR will be able to provide a range of services that can support grid integration of large quantities of intermittent and variable renewable resources. The plan also articulates our collective commitment to integrating DR into the CAISO's wholesale energy markets.

We reiterate our commitment to a strong demand response program consistent with D.12-04-045. We agree with parties who contend that demand response resources are likely to be able to provide capabilities which should reduce LCR needs recommended by the ISO. While the ISO did not study a scenario with additional demand response resources, it is reasonable to assume that some amount of demand response resources will be located in the LA Basin, be locally dispatchable, and available to meet LCR needs by 2020. Estimates of 2000 to 3000 MW of demand response are clearly overly optimistic for local reliability purposes, as these estimates are not specific to the LA Basin, may not be locally dispatchable and may not effectively reduce LCR needs.

[151] RT 607; 646.

In order to determine a reasonable level of demand response likely to be available by 2020 to reduce LCR needs, we take a conservative approach. We will assume a nominal level of 200 MW of dispatchable demand response resources that will be available in the LA Basin to reduce LCR needs by 2020. Since there appears to be at least 100 MW of demand response in the most effective locations now in the LA Basin (and 549 MW of total demand response resources now in that area), by 2020 it is likely that the actual amount available to reduce LCR needs in the LA Basin will be significantly higher – perhaps closer to DRA and CEJA's estimates of around 1000 MW. As the Commission, the ISO and the industry work together over time to clarify the technical characteristics for the circumstances in which demand response resources should count for meeting local capacity requirements (such as local dispatchability), our confidence in the viability of these resources for such purposes should grow. In the future, it is likely that there will be more consensus about how to include demand response resources in LCR forecasts.

4.2.4.3. Distributed Generation

Under Governor Brown's June 2010 Clean Energy Jobs Plan, approximately 6500 MW of new CHP would be added to the grid over the next 20 years with a plan to add 12,000 MW of distributed generation statewide by 2020. The Assembly Bill (AB) 32 Scoping Plan sets a goal of 4000 MW of new CHP by 2020.

The Commission's commitment to expanded distributed generation is supported by a multitude of programs, including the California Solar Initiative, Net Energy Metering, Self-Generation Incentive Program (SGIP), the Renewable Auction Mechanism (RAM), Renewable Market Adjusting Tariff (Re-MAT), Combined Heat and Power tariffs, and the Utility Photovoltaic and

Fuel Cell Programs. In 2013 the Commission will implement Senate Bill (SB) 1122 expanding offerings to bioenergy distributed generation projects. These programs commit IOU customers to substantial investment in distributed generation and promise to deliver thousands of megawatts.

The ISO scenarios assume between 271 MW and 1519 MW of distributed generation actually will be developed in the LA basin local area over the next 10 years, based on the standardized planning assumptions developed in R.10-05-006.[152] Most of this appears to be rooftop solar and other small solar installations. ISO witness Millar testified that if distributed generation increased beyond what the ISO is forecasting, that generally would lower the local capacity need. However, the ISO does not recommend relying on the 1519 MW distributed generation forecast in the Environmentally Constrained scenario, but on a range from 271 MW to 687 MW embedded within the other three scenarios. This is because the ISO claims the distributed generation level in the Environmentally Constrained scenario may be an "admirable goal" but "it is not a capacity amount that can be depended on for ensuring reliability of the bulk power system."[153]

The ISO does not consider it reasonable or prudent to rely on incremental CHP programs beyond what has been considered in the 2009 CEC forecast due to uncertainty that exists with regard to future increases in CHP development. However, Millar also contends that CHP should not be excluded from meeting reliability needs if such facilities can meet ISO technical characteristics. Further,

[152] DRA similarly estimates between 347 MW and 2468 MW of new CHP in SCE's region by 2020.

[153] Exhibit ISO-2 (Sparks/Millar) at 6-7.

Millar testified, in the context of state policy objectives supporting CHP: "We want to support [CHP] if there's some work we can do to help those programs or those resources meet these [reliability] needs providing they have the like characteristics."

As ISO witness Millar states, with regard to including energy efficiency in a demand forecast, "we would turn largely to the judgment of the CEC in developing their forecast."[154] We agree, and find that similar consideration should be given with regard to distributed generation forecasts by state agencies. We do not agree with the ISO's decision to unilaterally dismiss the CEC forecast of 1519 MW of distributed generation under the Environmentally Constrained scenario. This forecast has the same validity as CEC forecasts in the other three scenarios and should be considered as part of our analysis. However, we will adopt the ISO's recommendation to use the 339 MW projection of distributed generation, except for uncommitted CHP.

SCE witness Cushnie testified: "CHP has some of the same characteristics that conventional gas-fired resources would have, but they are not going to be as effective as (gas-fired resources) in meeting the need."[155] CEJA contends the ISO should have considered more CHP in its analysis, citing to the Governor's goals and a CARB 2008 Scoping Plan adopting a CHP goal of an additional 4000 MW of installed CHP capacity by 2020. Specifically, CEJA recommends inclusion of at least 285 MW of incremental CHP should be included in the ISO forecast for the LA basin local area, which is a proportion of 360 MW of incremental CHP for SCE's total territory (this amount is taken from the Scoping Memo in

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[154] RT 492.

[155] RT 731.

R.10-05-006.) CCC presents a report showing a medium projection of 621 MW of additional CHP by 2020.

We find that there is the potential for additional CHP to be realized over the ISO's Trajectory scenario. The exact amount that can be assumed is not clear from the record; however, it is reasonable to assume that some amount of uncommitted CHP will come to fruition in the LA basin local area before 2021. Thus, we find there will be more distributed generation than was included in the ISO Trajectory scenario. SCE's point that CHP may not be as effective as gas-fired generation in meeting LCR needs is important; it is necessary to model the impacts of increased CHP. This is what the ISO has done in the four scenarios it studied; Table 3 – 6 herein show that the ISO assumed between 271 MW (Base scenario) and 1519 MW (Environmentally Constrained scenario) of distributed generation. The ISO's recommended Trajectory scenario includes 339 MW of distributed generation.

As with uncommitted energy efficiency, we are convinced that the ISO should have included some projection of uncommitted CHP into its models. As with energy efficiency, a significant amount of what the CEC categorized in 2009 as uncommitted CHP is now more certain to exist. As discussed in Section 4.2.4.1 herein, we find that the ISO's Environmentally Constrained scenario sensitivity analysis includes a reasonable maximum level of uncommitted energy efficiency for the LA basin local area. This same forecast also includes the full amount of uncommitted CHP in the CEC forecast. The combination of uncommitted energy efficiency and uncommitted CHP led to a reduction in LCR needs of 828 MW in the one ISO scenario which modeled this modification. We will consider this level as part of our authorization of what level of LCR need SCE is authorized to seek.

4.2.4.4. Energy Storage

Under California Governor Brown's June 2010 Clean Energy Jobs Plan, approximately 3000 MW of energy storage would be added to the grid to meet peak demand and support renewable energy generation.

CESA recommends that the Commission closely coordinate this proceeding with the Energy Storage Rulemaking, R.10-12-007. CESA calls for the full integration of storage into long-term procurement planning as "a powerful and resource adequacy-improving asset class."[156] CESA contends that energy storage can meet LCR needs and, like generation, is dispatchable.[157]

CEJA contends it is not reasonable that the ISO did not consider any energy storage in its analysis.[158] CEJA claims that energy storage has been found to be more effective than conventional peaking generation, and that both SCE and the ISO recognize the value of storage and the increasing viability of storage technology.

ISO witness Millar testified that, at this time, there are no energy storage facilities on the net qualifying capacity (NQC) list for local capacity[159] (i.e., eligible to be counted for RA purposes) and that the ISO has not identified any energy storage projects in its transmission planning process.[160] However, he stated that there is a process by which any energy storage facilities which emerge could be placed on the NQC list and be eligible to provide local reliability for RA

[156] Exhibit CESA-1 (Lin) at 8.

[157] Exhibit CESA-2 (Lin) at 2.

[158] Exhibit CEJA-1 (Powers) at 14-19.

[159] RT 347.

[160] RT 404.

purposes.[161] Similar to demand response resources, Millar testified that if energy storage technologies met certain performance requirements, they could count for reliability purposes.[162] However, he testified that "we don't know" if energy storage can meet ISO technical characteristics in the next ten years.[163]

SCE witness Minick testified that there are "only a few test programs for energy storage on our system, and they are not specifically located in areas that would be of any benefit for LCR analysis." He continued: "We have looked at 20 to 30 different energy storage technologies, and we have presented that information to the Commission, and I don't think we have found many, if any, cost-effective."[164]

We are examining the feasibility of energy storage technologies in R.10-12-007. In that proceeding we are considering multiple energy storage options to determine the cost-effectiveness of these potential resources. At this time we do not have sufficient information to determine how many viable energy storage facilities will emerge between now and 2021 that can be used for local reliability purposes in the LA basin local area (or elsewhere). We will not consider a modification to the ISO local reliability need forecast for energy storage for the LA basin local area at this time.

However, we intend to promote the inclusion of energy storage technologies in SCE's upcoming procurement process. CEJA details a number of SCE energy storage initiative and projects underway that will increase energy

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161 RT 348-349.

162 RT 355.

163 RT 461.

164 RT 948.

storage capacity in its territory (although largely outside of the LA Basin).[165] As a result, CEJA recommends a minimum procurement level of 48 MW of energy storage resources, based upon a storage assumption of 100 MW for the LA Basin, with the Western LA Basin as approximately 48% of the LA Basin.[166] As explained below, we will require that SCE procure at least 50 MW of energy storage resources for LCR purposes in the LA basin local area. We view this as a reasonable and modest level of targeted procurement of an emerging resources, and as an opportunity to assess the cost and performance of energy storage resources.

5. Minimum and Maximum Procurement Authorizations

As noted above, SCE recommends that we authorize a range of procurement from zero to 3871 MW. While SCE and many parties have significant concerns about the LCR procurement levels recommended by the ISO, SCE proposes the widest possible range of procurement flexibility. Other parties find fault in SCE's expansive proposal. CEJA, for example, recommends that SCE's proposal be rejected as "a bad idea to take an economically risky (and environmentally harmful) scenario, and simply shift the burden of this risk to ratepayers."[167]

To address this concern, TURN recommends both a minimum and maximum procurement authorization level, partially to "provide purchaser flexibility when negotiating with bidders."[168] SCE contends that a minimum

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165 CEJA Opening Brief, pp. 55-56.

166 CEJA Reply Brief, p. 2.

167 Exhibit CEJA-5 (May) at 2.

168 Exhibit TURN-1 (Woodruff) at 22.

LCR procurement target is not useful as the specific proposals and options available to meet the LCR need are not known at this time; instead SCE would have the Commission finalize appropriate LCR levels in SCE's future application for approval of proposed LCR projects.[169]

We agree with SCE that not all information is known. We can and will further refine LCR authorization requirements in future long-term procurement planning proceedings. However, we take seriously the ISO's concern (seconded by SCE and others) that there are some procurement opportunities associated with gas-fired power plants which may be lost if there is a delay in moving forward, due to a likely seven to nine year lead time. We do not agree with DRA that "there is zero reliability risk of waiting to procure additional fossil resources" for 2021.[170] Gas-fired resources are appropriate resources to procure for their technical reliability characteristics and for cost considerations; however, we discuss below that procurement should be consistent with the Loading Order to the extent possible.

We will set a minimum LCR procurement level. There is some uncertainty about what how much uncommitted energy efficiency will be available to reduce demand by 2021, and how much uncommitted CHP will be available to fill LCR needs. However the forecast of zero for these resources included in the ISO Trajectory scenario is not reasonable. Therefore, the LCR need is less than the ISO forecasts in its Trajectory scenario. At the same time, the record establishes that there is a significant need for LCR resources to replace retiring OTC plants

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[169] Exhibit SCE-2 (Cushnie) at 7.

[170] RT 912.

by 2021 under every ISO scenario and sensitivity analysis. It is reasonable to require a minimum procurement level to ensure reliability.

TURN recommends a "circuit breaker" mechanism if the Commission allows procurement of a lower amount of capacity than the ISO recommends (which is the maximum level SCE recommends.) The "circuit breaker" would occur "if the prices of one or more bids greatly exceed a reasonable cost."[171] SCE argues this proposal is not needed if the Commission does not adopt a minimum LCR procurement target.[172] However, we do adopt a minimum LCR procurement level. While we are cognizant of the potential for bids with excessive cost, already existing mechanisms such as cost-of-service contracts and reliance upon requests for offers provide some ratepayer protection. Further, the Commission-established Procurement Review Groups, Independent Evaluators and Energy Division staff review also provide important and substantive ratepayer protections.

Adjustments to the ISO forecasts to include the maximum reasonable level of uncommitted energy efficiency and CHP, lead to the ISO's Environmentally Constrained scenario sensitivity analysis. As shown in Table 2, this analysis leads to a forecast of 1042 MW of LCR need for effective sites. However, this scenario is a derivative of the Environmentally Constrained scenario. The difference between the Trajectory scenario and the Environmentally Constrained scenario is that the latter included 1519 MW of supply-side distributed generation,[173] as compared to 339 MW in the Trajectory scenario. There is no

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[171] Exhibit TURN-1 (Woodruff) at 22.

[172] Exhibit SCE-2 (Cushnie) at 9-10.

[173] Some distributed generation is embedded in the CEC's demand forecast.

credible evidence in the record that there will be 1519 MW of supply-side distributed generation in the LA Basin by 2020.

We agree with the ISO, SCE and others that the Trajectory scenario is appropriate for determining LCR needs. However, we have determined herein that it is appropriate to reduce the ISO forecasts to account for the likelihood that 828 MW of uncommitted energy efficiency and CHP will exist, and that at least 200 MW of locally-dispatchable demand response will exist.

The ISO did not provide a sensitivity analysis for the Trajectory scenario. It is possible to roughly calculate the impact of including more energy efficiency, CHP and demand response resources into the Trajectory scenario. The sole difference between the ISO Environmentally Constrained scenario and the sensitivity study for this scenario is the inclusion of uncommitted energy efficiency and CHP. The ISO shows that these resources would decrease LCR needs by 828 MW. It is reasonable to assume that modeling uncommitted energy efficiency and CHP into the Trajectory scenario would result in at least this much reduction in LCR needs (given that the Trajectory scenario starts with a higher LCR need). We will assume that inclusion of 100% of uncommitted energy efficiency and 100% of uncommitted CHP will reduce the LCR need in the Trajectory scenario by 800 MW (with rounding). In addition, we have determined that we will assume a conservative projection of 200 MW of locally dispatchable demand response resources.

In sum, the Trajectory scenario LCR forecast should be reduced by a maximum of 1000 MW to account for undercounted resource availability. We therefore adopt a minimum LCR need of 1400 MW for the West LA sub-area of the LA basin local area.

We have stated herein that potential demand response and energy storage resources are likely to be able to reduce LCR needs in the future. A way of looking at this is that even if some uncommitted energy efficiency and/or CHP resources included in the ISO forecast do not ultimately appear, there is a reasonable likelihood that other resources including locally-dispatchable demand response (beyond our conservative forecast of 200 MW) and/or energy storage resources will appear which can similarly fill or reduce LCR needs. Alternatively, there may also be transmission-related improvements which can decrease LCR needs. These additional potential resources strengthen our determination that far lower levels of new generation procurement are needed to satisfy LCR needs in the LA basin local area than recommended by the ISO in the Trajectory scenario.

We will also set a maximum procurement level. SCE's proposal for a maximum procurement level is based on the highest ISO forecast level, given less efficient locations.[174] Our analysis of the demand forecast used by the ISO convinces us that the ISO's recommendations for procurement of LCR needs in the LA basin local area are too high. Further, we are convinced that inevitably changing circumstances over the next several years must be taken into consideration. By adopting a lower maximum procurement level than the ISO recommends, the maximum levels are unlikely to turn out to be too high. If our adopted maximum procurement level is too low, there will be timely

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[174] SCE's method for recommending maximum LCR levels appears to be slightly different than the ISO's method for calculating the upper bound for LCR needs in each scenario. The ISO considered the least effective OTC sites in each local area, while SCE used less effective locations in each local area.

opportunities to obtain additional resources in future long-term procurement planning proceedings.

For determining the maximum procurement level, we reiterate that this projection should include a reasonable amount of uncommitted energy efficiency and uncommitted CHP. Again, this projection should also include information regarding potential demand response and energy storage resources which can meet LCR needs. In addition, the location of energy efficiency and CHP installations in the LA Basin local area (unknown at this time) may not be as effective in reducing LCR needs than other resources, such as gas-fired generation located at current OTC sites.

As with our determination of a minimum procurement level, we will assume subtraction of 1000 MW of uncommitted energy efficiency, uncommitted CHP and demand response resources from the Trajectory scenario forecast. For the maximum procurement level, we will add back 400 MW to reflect possible effectiveness factors. Therefore, we adopt a maximum LCR need of 1800 MW for the West LA sub-area of the LA basin local area.

The ISO forecasts provide a range of LCR needs depending upon location of new capacity. The low end of the ISO forecasts assume the new capacity is located at the most effective current OTC sites, and the high end assumes less effective OTC sites. Our determination of the minimum procurement level implicitly assumes that new capacity will be sited at the most effective sites. However, this may not be the case. SCE shall use the most up-to-date effectiveness ratings in its solicitation process.

As discussed further below, we will revisit LCR needs in the next long-term procurement proceeding, expected to commence in 2014. It is possible that in the next long-term procurement proceeding there will be shown to be a need for more LCR procurement than the maximum procurement levels we establish today. We consider today's decision a measured first step in a longer process. If as much or more of the preferred resources we expect do materialize, there may be no need for further LCR procurement in this time period. If circumstances change, there may be a need for further procurement. We are confident that today's decision is the appropriate and considered step at this time.

6. Long-Term Local Capacity Requirements for Big Creek/Ventura Local Area

In the Big Creek/Ventura local area, the Ormond Beach and Mandalay power plants are OTC plants with four units that are scheduled to shut down per SWRCB regulations before 2021. In total, these units currently have approximately 2000 MW of capacity.

The ISO recommends LCR procurement of 430 MW in the Moorpark sub-area of the Big Creek/Ventura local area under all RPS scenarios, without a range for effectiveness of sites. This results from a need to mitigate reliability issues in the Moorpark sub-area of the Big Creek/Ventura local area, caused by a contingency of voltage collapse from a potential loss of area transmission lines.[175] The ISO analysis for the Big Creek/Ventura local area is consistent with the methodologies discussed above for studying long-term local capacity needs for the LA Basin local area.

SCE recommends deferring authorization for procuring additional local capacity in the Big Creek/Ventura local area until the next LTPP cycle (expected to commence in 2014). SCE contends that barriers to construction of new

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[175] Exhibit ISO-1 (Sparks) at 13-14.

LCR generation is not as difficult in the Big Creek/Ventura local area as in the LA basin local area, because "this area does not have as many, or as stringent, siting restrictions as the LA basin."[176] SCE further argues 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.[177]

DRA contends that there is no immediate need for LCR generation in the Big Creek/Ventura local area and that ongoing review of LCR needs is required. DRA acknowledges that there would be a loss of 1946 MW in the area due to OTC retirements by 2020.[178] However, based on a load and resources table, DRA contends that there is a surplus of resources (up to 1820 MW) in the Big Creek/Ventura local area when considering the effect of demand side resources.[179] DRA believes that it would not take as long to go through the process to start running a new fossil-fueled power plant in the Big Creek/Ventura local area as in the LA basin local area, due to fewer concerns about siting.[180] DRA maintains that this timeframe would allow the Commission to revisit whether alternative preferred resources materialize in the area. Therefore, DRA contends the risk of not procuring now is minimal if not zero. CEERT agrees with SCE and DRA that no LCR procurement is required to be considered until the expected 2014 long-term procurement proceeding.[181]

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176 Exhibit SCE-1 (Minick) at 10-11.

177 Exhibit SCE-2 (Cabell) at 20.

178 Exhibit DRA-1 (Fagan) at 19.

179 Exhibit DRA-1 (Fagan) at 17-22 and Table RF-3.

180 RT 920-922.

181 CEERT Opening Brief at 31.

Calpine agrees with DRA that further analysis of the Moorpark sub-area is needed before LCR authorization in the Big Creek/Ventura local area is granted. Calpine sponsored an analysis that "suggests that there are potential transmission upgrades that may reduce or eliminate the need for OTC replacement generation in the Big Creek/Ventura local area."[182] Specifically, Calpine argues that one of several transmission alternatives was identified by the ISO that can reduce the LCR need to 100 MW, while other transmission alternatives suggested by Calpine can reduce the LCR need to from zero to 230 MW.[183]

GenOn contends that Calpine's examples of transmission projects are not feasible or desirable solutions for addressing local reliability needs.[184] GenOn contends it is necessary to adopt an LCR need determination for the Big Creek/Ventura local area by the end of 2012 because of plant closures expected in 2020.[185] GenOn contends that it will take seven years or more until commercial operation of new gas-fired plants can commence. GenOn does not agree with SCE that it is not as challenging to develop new LCR generation in the Big Creek/Ventura local area.[186] GenOn also discusses implementation plans it submitted to the SWRCB for several OTC plants, including the Mandalay and Ormond Beach Generating Stations in the Big Creek/Ventura local area. While GenOn originally intended to keep the plants open via a compliance track

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[182] Exhibit Calpine-2 (Calvert) at 2, details in at 2-11.

[183] Calpine Opening Brief at 7.

[184] GenOn Opening Brief at 8.

[185] Exhibit GenOn-2 (Beatty) at 2.

[186] Exhibit GenOn-2 (Beatty) at 7-9.

acceptable to the SWRCB, it now intends to retire (and potentially replace) the plants by the SWRCB compliance deadline.[187]

6.1. Discussion

As with the LA basin local area, there are questions about the ISO forecasts for the Big Creek/Ventura local area. Here, the ISO also did not include any values for uncommitted energy efficiency and uncommitted CHP. As with the LA basin local area, it is likely that the ISO models overstate the LCR need for the Big Creek/Ventura local area for this reason. Similarly, it is more likely that at least some amount of demand response and/or energy storage will emerge in the Big Creek/Ventura area which can be used to meet LCR needs in the next decade, then that there will be zero amount of these resources.

Calpine has shown that there are several transmission possibilities which might reduce LCR needs in the Big Creek/Ventura local area. It is not clear that all of Calpine's suggestions are feasible. However, the ISO did identify a non-generation (transmission) alternative similar as feasible to be completed.[188] This transmission option would result in a total OTC need of 100 MW, instead of 430 MW as proposed by the ISO.[189] The ISO disagrees with Calpine about whether this option is a superior mitigation solution in the Moorpark area, contending that either way there would still be a need for replacement generation.

While it may be mathematically possible to show that some combination of preferred resources and transmission solutions could reduce the LCR need to

[187] Exhibit GenOn-1 (Beatty) at 3-5.

[188] Exhibit ISO-23 (Sparks) at 2.

[189] Exhibit ISO-23 (Sparks) at 3.

zero (or near zero), there are technical issues and operational benefits from having specific types of in-area generation with the characteristics of the current OTC plants for the Moorpark area. We find that the ISO has shown that there is a need for this type of in-area generation in the Moorpark area, in order to avoid adverse impacts on transmission voltages and loadings under some operation conditions.

The ISO contends that there is a need for 430 MW of total in-area generation in the Moorpark area, even with a viable transmission alternative (or any preferred resources which do not have similar operating characteristics to OTC plants.) The ISO recommendation appears to be conservative on this point, as the ISO has not shown that 430 MW is the minimum amount of LCR need necessary to maintain vital operational characteristics. While some in-area generation similar to existing plants appears to be necessary, some combination of transmission alternatives and preferred resources will necessarily reduce the LCR need below the ISO's projections.

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. The most likely locations for new OTC-like generation are the sites of the current OTC plants. The record shows that it may take seven years or more until operations commence in these locations.

The combination of likely preferred resource options and at least one viable transmission solution lead to the conclusion that less than 430 MW is needed for the Moorpark sub-area. It is reasonable to provide SCE with a range of procurement levels to allow SCE to take advantage of different technologies and combinations of potential solutions. TURN's recommendation to allow SCE to procure up to 2/3 of the ISO's recommendation leads to a total of approximately 290 MW. Two of the retiring Mandalay OTC plants have an NQC of 215 MW.[190] It is reasonable to assume that there is a need for approximately the same size replacement generation. Therefore the minimum procurement level for the Moorpark sub-area will be 215 MW. A reasonable maximum level is the 290 MW level per the TURN recommendation. We will authorize SCE to start the process to procure between 215 and 290 MW in the Moorpark sub-area of the Big Creek/Ventura local area, consistent with the process described herein.

7. Procurement Process

7.1. Technical requirements for local capacity

In this decision, we have determined that SCE should be authorized to start a process in 2013 to enter into contracts for between 1400 MW and 1800 MW in the LA basin local area, and 215 to 290 MW in the Big Creek/Ventura local area. Our determination accounts for a reduced demand level due to more energy efficiency and demand response resources than assumed by the ISO, and additional CHP resources. Here we discuss the process for procurement of resources to meet these needs.

One significant issue is what technologies and resources SCE should be authorized to procure. The ISO does not assume any particular technology

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[190] As shown in Table 1, the Ormond Beach plants have a much higher NQC than the 435 MW recommendation from the ISO. Therefore, it is not reasonable to expect plants of this larger size to be replaced.

would be required to fill the local capacity needs, according to ISO witness Sparks: "As long as the resources are in the location where they are needed in these local areas, and they have characteristics of gas-fired generation, I don't believe the ISO has a preference on exactly what type of resources."[191] Regarding distributed generation, the ISO studied a scenario with a high level of renewable distributed generation (the Environmentally Constrained scenario). Referring to distributed generation, Sparks suggested that further study would be needed "to the extent that some of these nonflexible resources are very large, and these large magnitudes are meeting local needs…we would probably need to study all seasons and all load levels to ensure the system can continue…to reliably operate."[192]

SCE witness Cushnie testified that SCE is technology neutral in terms of the resources that it would acquire.[193] In general, SCE would procure resources that will meet ISO criteria for local reliability. However, as ISO witness Millar testified, there is no specific written protocol or tariff that can be referenced to determine the ISO's performance criteria for local reliability.[194] The ISO finds that gas-fired generation meets its criteria, as well as any other resources (or combination of resources) which have the same performance criteria as gas-fired generation. Demand response resources and CHP may meet the ISO's criteria, but not at this time. It is possible that other resources will pass the ISO test as

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191 RT 201.

192 RT 208–209.

193 RT 604.

194 RT 355-356.

well in the future. Of course, acquisition of more energy efficiency and demand side resources would reduce the LCR need.

Our concern is, without knowing upfront exactly what the ISO would find acceptable, that SCE could procure resources that would not past ISO muster. In that case, the ISO -- consistent with its reliability mandate -- could seek Commission action authorizing additional resources (thus lowering the value to ratepayers of already-procured resources) or could use its own authority (or seek new authority) to contract with resources to meet local needs (also increasing total costs). Either of these approaches is sub-optimal, both in cost terms and in environmental terms.

SCE proposes to use existing RA program rules to assess the effectiveness of proposed generation solutions for meeting LCR need. SCE proposes to identify its assumptions on the effectiveness of any resource for which the RA program does not provide clear guidance.[195] We will adopt SCE's proposal.

The ISO states that it will work with SCE and the Commission to develop the requirements needed for resources to compete in the procurement process.[196] We will require SCE to consult with the ISO regarding ISO performance characteristics (such as ramp-up time) for local reliability. In its application to procure specific resources to meet local reliability needs (discussed herein), SCE shall provide documentation of such efforts and how SCE meets ISO performance requirements.

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195 Exhibit SCE-2 (Silsbee) at 5.

196 ISO Opening Brief at 3.

7.2. Consistency with the Loading Order

SCE proposes to demonstrate that any proposed contract is consistent with the Loading Order by identifying each preferred resource and then assessing the availability, economics, viability and effectiveness of that supply in meeting the LCR need.[197] Per SCE witness Cushnie, SCE would also perform a cost/benefit analysis of the various procurement options.[198] This study would be performed in parallel with any RFO and/or bilateral negotiations for supply.[199]

Several parties have raised concerns that SCE's procurement process might not be consistent with the Loading Order in the Energy Action Plan. Vote Solar contends that preferred resources are endowed with advantages that are difficult to monetize or otherwise capture in an all-source RFO; for example, modularity (ability to be deployed in smaller MW), less environmental impact, smaller sites, and avoidance of outages and losses.[200] CEJA contends that implementation of the ISO recommendations for how to meet LCR needs will lead to excessive and unnecessary natural gas-fired capacity.[201] Similarly, Sierra Club contends that the ISO's models "turn the Loading Order upside down by creating a framework that favors conventional generation over preferred resources."[202]

CAC claims there are about 60 MW of existing CHP capacity in the Western LA basin sub-area, and 70 MW of existing CHP in the

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[197] Exhibit SCE-2 (Silsbee) at 4; RT 612-613; RT 627 (Cushnie).

[198] RT 626-627.

[199] RT 650.

[200] Exhibit Vote Solar-2 (Gimon) at 2–3.

[201] Exhibit CEJA-1 (Powers) at 31-32.

[202] Sierra Club Opening Brief at 13.

Big Creek/Ventura local area, which were not included in ISO studies. In order to be consistent with the Loading Order and obtain this capacity to meet LCR needs, CAC recommends that the Commission establish a rebuttable presumption that existing resource offers (presumably CHP) priced no greater than the cost of new conventional fossil generation be deemed reasonable in the IOU procurement process.[203]

CEERT recommends a process for SCE to procure preferred resources as part of its solicitation. This process includes consultation with the ISO and prospective bidders to establish metrics and protocols for dispatchability and performance of preferred resources. Next, SCE would issue a Request for Qualification to establish the likely quantity and price range of available qualified preferred resources. Then, a cost-effective level of transmission and load-shedding which could meet LCR need would be established by the Commission based on existing and new studies. Through this process, CEERT contends there will be sufficient data available to conduct a "directed procurement" of LCR need.[204]

IEP recommends an all-source RFO in which all resources can compete on an equal basis.[205] IEP proposes that any uncommitted energy efficiency and similar resources which are unable to qualify to compete in an all-source RFO would remain outside of the procurement mechanism until they materialize. At that point, these resources would be considered as committed, and reduce the

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[203] Exhibit CAC-1 (Ross) at 3, 8-9.

[204] Exhibit CEERT-2 (Caldwell) at 3-4.

[205] Exhibit IEP-1 (Monsen) at 15.

amount of demand and amount of procurement needed in future procurement proceedings.[206]

7.3. Discussion

We have already determined herein the need to modify the ISO's recommendations for LCR needs in the LA basin local area to take into account reasonably-expected levels of energy efficiency, demand response resources and CHP (and the potential for more demand response resources as well as energy storage resources to become available which can meet LCR requirements). By assuming higher levels for these resources than the ISO, we are promoting the policies of the Loading Order, and reducing the anticipated LCR need.

Because the range of LCR need we establish herein includes between 50% and 100% of uncommitted energy efficiency and uncommitted CHP resources as well as a conservative forecast of demand response resources, SCE will need to ensure that these resources do exist in the future in order to ensure local reliability. As part of our review of SCE's procurement plan, and when considering SCE's procurement application, we will require SCE to show that it has done everything it could to obtain cost-effective demand-side resources which can reduce the LCR need, and cost-effective preferred resources and energy storage resources to meet LCR needs. This task includes efforts already underway and approved in other Commission proceedings, with an eye to focusing such efforts in the specific local geographic areas where LCR needs exist. In other words, for the purposes of meeting LCR needs, it will do no good

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[206] IEP Opening Brief at 5-6.

to procure preferred resources such as energy efficiency outside of specific portions of the LA basin or Big Creek/Ventura local areas.

With respect specifically to SCE's procurement of RPS-eligible resources to meet some or all of the LCR needs identified in this decision, this decision does not set up any new RPS procurement processes. SCE should follow existing RPS program procurement authorizations, rules, and processes in its procurement of resources to meet these LCR needs. In SCE's procurement plan discussed below, we require SCE to detail the RPS procurement authorizations and processes that support its plans to acquire RPS-eligible resources to meet these LCR needs.[207]

We recognize that requirements regarding preferred resources must be reconciled with the additional requirement to consult with the ISO on performance criteria. We are confident that the dual objectives of reliability and adherence to the policy objectives of the Energy Action Plan can both be met.

In addition to meeting reliability criteria and consistency with the Loading Order, LCR procurement by SCE must be at least cost to ratepayers. SCE witness Cushnie testified that SCE "has every interest to do this in the least possible cost to the customers (because) there's no upside to the utility in doing this

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[207] In its 2012 RPS procurement plan, SCE proposed that it would not hold a solicitation for RPS-eligible resources in the period covered by the 2012 RPS procurement plan. In D.12-11-016, the Commission allowed SCE not to hold a solicitation for RPS-eligible resources and put in place a parallel restriction on SCE's ability to enter into bilateral contracts for RPS-eligible resources during the same period. In D.12-11-016 at 57, the Commission stated that "should SCE determine it has an unmet RPS need during the 2012 solicitation cycle, we will revisit SCE's request to not hold a solicitation and the corresponding restriction adopted today on bilateral contracts." SCE should indicate in its procurement plan whether it intends to seek Commission reconsideration of the solicitation and bilateral contracting determinations in its 2012 RPS procurement plan.

procurement."[208] We will review SCE's efforts at cost minimization in SCE's forthcoming Application. However, balancing the three criteria of ensuring reliability, consistency with the Loading Order and cost-minimization is a challenge.

SCE explains that it intends to capture all cost-effective energy efficiency that can meet LCR needs.[209] Overall, SCE further explains its intention for load reduction resources:

> For preferred resources, SCE will assess the cost-effectiveness of such resources relative to supply-side options. If load reduction in the local area appears to be cost-effective, SCE will engage the CAISO to conduct transmission modeling load flow analysis to determine the operational effectiveness of load reduction programs and technology. SCE will reduce its procurement of supply-side resources to accommodate the future procurement and/or development of load reduction programs and technologies to the extent that they are determined to be cost-effective and operationally effective in reducing the identified LCR need.[210]

SCE's process for balancing objectives with regard to demand reduction resources is reasonable. We will also require SCE to apply a similar balancing to all preferred resources; we agree with SCE's recommended approach to pursue the most competitively-priced CHP and renewable resources, consistent with meeting LCR locational needs and technical characteristics. The remainder of SCE's LCR need will need to be met by supply-side resources and cost-effective transmission upgrades.

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[208] RT 760-761.

[209] RT 609-610.

[210] SCE Opening Brief at 5-6.

The record shows that there may be a significant amount of energy storage capacity and/or demand reduction from demand response resources in the next several years which are not included in any ISO model. We have determined that a significant amount of these resources may be available to meet or reduce LCR needs by 2021, even beyond the projections in the ISO models. We recognize there may be barriers to integration of these resources, including technical issues regarding whether such resources can meet ISO LCR criteria. At the same time, the prospect of additional resources to meet or reduce LCR needs provides an opportunity to further our Energy Action Plan through additional procurement of resources other than conventional gas-fired generation.

Because there is a strong likelihood that additional preferred and energy storage resources not included in our maximum procurement authorization (and potential changes to the transmission system) will be available to effectively meet or reduce LCR needs by 2021, we will require that SCE procure no more than 1200 MW from conventional gas-fired resources in the LA basin local area. The record shows that the most certain technology which can meet LCR needs (from the ISO's perspective) is gas-fired generation. In order to ensure a base level of procurement certain to ensure reliability under the most stringent criteria, we will require that at least 1000 MW in the LA basin local area be from gas-fired generation. In addition, because we intend to promote promising technologies with a strong potential to effectively meet LCR needs, we will require that SCE procure at least 50 MW of energy storage resources as part of its procurement plan for the LA basin local area.

Several parties, in their comments on the Proposed Decision, recommend that we include a requirement that some specified amount of preferred resources be required to be procured. One rationale is that if we have a minimum procurement level for gas-fired and energy storage resources, we should also do so for preferred resources consistent with the Loading Order. Because the Proposed Decision has been modified to increase the minimum procurement level, there is an opportunity to specify further how the minimum procurement level will be achieved. We will require that at least 150 MW of the minimum procurement level be procured through preferred resources.

To summarize: SCE shall procure at least 1400 MW to meet 2021 LCR needs in the west LA sub-area of the LA basin, using the process delineated herein. Included in that 1400 MW shall be 1000 - 1200 MW of conventional gas-fired generation,[211] at least 50 MW of energy storage capacity, and at least 150 MW of capacity from preferred resources. All additional resources beyond the minimum requirement must also be from preferred resources, or from energy storage resources. SCE is not authorized to procure more than 1800 MW of capacity to meet 2021 LCR needs in this part of the LA basin. All resource procurement is expected to follow the principles of least cost/best fit within these constraints. For example, if more than 50 MW of energy storage resources bids into the solicitation process, the most cost-effective and best-located projects should be used to fill the 50 MW requirement.

In addition to authorizing SCE to procure new generation resources, SCE continues to be authorized or required to obtain other resources, as detailed in decisions in the Commission's energy efficiency demand response, RPS and other proceedings. Nothing in this decision is intended to supersede or limit any authority or requirement stemming from any other commission proceeding.

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[211] Conventional gas-fired generation includes CHP resources that are electrically equivalent to conventional generation.

SCE's efforts to obtain these resources are critical to ensuring that the assumptions embedded in this decision will become reality and the reliability needs in SCE's territory will be met.

7.3.1. RFOs and Bilateral Negotiations

One way for SCE to procure the LCR resources we authorize in this order will be to issue one or more RFOs.[212] For example, an RFO to fill LCR needs could specify the amounts needed, the location needed, and technical requirements.

SCE agrees with TURN that an RFO can be very effective in determining the most competitive options for meeting LCR needs. However, SCE requests the flexibility to determine whether it should hold an RFO or not in local capacity areas with limited or no alternatives, because in such a case an RFO may not yield competitive or cost-effective results. SCE contends that such problematic results could occur because the existing generation location has numerous inherent advantages that it can seek to increase costs in a solicitation process.[213]

TURN agrees that some cost-of-service contracts may be needed for OTC unit owners in certain sub-areas where market power exists, in order to ensure reasonable costs to ratepayers.[214] Vote Solar contends that an all-source RFO could give rise to market power mitigation issues to address potentially unreasonable costs, irreversible outcomes, and a cumbersome process to take

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[212] SCE witness Cushnie testified that SCE conducts numerous RFO solicitations for procurement, including all-source solicitations, RPS solicitations and CHP solicitations. RT 686.

[213] Exhibit SCE-3 (Cushnie) at 8.

[214] Exhibit TURN-2 (Woodruff) at 3.

into account unique characteristics of preferred resources. CEJA proposes a phased RFO process, starting with a solicitation aimed at energy efficiency, then one for demand response, and on through the Loading Order.[215]

IEP recommends annual all-source solicitations after setting clearly defined performance requirements and obligations for various resource types, but cautions that there might be concerns about whether energy efficiency and demand response resources can be relied upon for firm capacity and deliverability.[216] IEP supports cost-of-service contracts if there is an IOU showing and a Commission finding of local market power.[217] GenOn also supports use of cost-of-service contracts in the situation where a solicitation does not yield robust results.[218]

AB 1576[219] (codified as § 454.6) authorizes the use of cost-of-service contracts to facilitate investment in the replacement or repowering of older, less-efficient thermal generation facilities when the ISO certified that the project is needed for local reliability. Section 454.6 states:

> (a) A contract entered into pursuant to Section 454.5 by an electrical corporation for the electricity generated by a replacement or repowering project that meets the criteria specified in subdivision (b) shall be recoverable in rates, taking into account any collateral requirements and debt equivalence associated with the contract, in a manner

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215 CEJA Opening Brief at 43.

216 Exhibit IEP-1 (Monsen) at 12-17, 21.

217 Exhibit IEP-1 (Monsen) at 8-11.

218 Exhibit GenOn-2 (Beatty) at 12.

219 Stats. 2005, ch. 374.

determined by the commission to provide the best value to ratepayers.

(b) To be eligible for rate treatment in accordance with subdivision (a), a contract shall be for a project which meets all of the following criteria:

1. The project is a replacement or repowering of an existing generation unit of a thermal powerplant.
2. The project complies with all applicable requirements of federal, state, and local laws.
3. The project will not require significant additional rights-of-way for electrical or fuel-related transmission facilities.
4. The project will result in significant and substantial increases in the efficiency of the production of electricity.
5. The Independent System Operator or local system operator certifies that the project is needed for local area reliability.
6. The project provides electricity to consumers of this state at the cost of generating that electricity, including a reasonable return on the investment and the costs of financing the project.

In situations where an RFO may not result in a reasonably priced contract, SCE proposes a targeted bilateral negotiation that may result in a cost-effective cost-of-service PPA option.[220] SCE contends that § 454.6 provides the option of using cost-of-service contracts to replace or repower existing generation. SCE witness Cushnie describes the relationship between an RFO solicitation and bilateral negotiations:

[220] Exhibit SCE-3 (Cushnie) at 8.

> If Edison was to negotiate separately through bilateral negotiations, the potential for a cost of service contract consistent with the legislation…the counterparty will not necessarily know what Edison's options are with respect to pursuing preferred resources with respect to transmission solutions. So it gives Edison more leverage in those negotiations that if we can't negotiate a contract that is reasonable, that we can then move to these other forms of procurement. But if we conduct the solicitation first and conclude that the solicitation was not competitive, we now have reduced any sort of leverage we might have in a subsequent bilateral negotiation because that will have informed the counterparty that there were no competitive options and now Edison just wants to negotiate on price. So it's a judgment call at the end of the day as to what makes the most sense.[221]

It is reasonable to authorize SCE to use either or both RFOs and cost-of-service contracts in its LCR procurement process. Both methods are intended to fill the LCR needs identified in this order, and to do so consistent with the Loading Order and cost minimization. We agree with SCE and other parties that cost-of-service contracts (also called bilateral contracts) are allowed under § 454.6 under specified circumstances which are likely to result in a procurement process as a result of this decision. Therefore, § 454.6 cost-of-service contracts are an option that SCE will be able to use in situations where there is significant market power that would be detrimental to ratepayers.

SCE opposes requiring all resources to bid into a single all-source RFO. SCE witness Cushnie contends: "Certain preferred resources just aren't going to be viable in (an all-source) solicitation," and that he is not aware of a preferred

[221] RT 641.

resource ever prevailing against a conventional resource in an all-source RFO.[222] Instead, SCE recommends studying ways to assess the effectiveness and potential use of preferred resources separate from an RFO.[223] SCE maintains that these studies are necessary because such programs cannot be reasonably expected to be developed and bid into a utility solicitation to meet a need that begins in 2020 and extends for ten years or more.

We agree that load reduction programs may not fit well into a typical RFO. SCE witness Cushnie testified that "to the extent we can get comfort that the economics and the viability are there, we can do studies to see if that can reduce the LCR need to meet with supply side resources."[224] It is not clear exactly what SCE intends through this study process. However, we have already assumed a significant amount of preferred resources in determining the minimum and maximum LCR levels for the LA basin local area. SCE should continue to assess and implement all ways to include cost-effective and viable preferred resources to reduce LCR needs. As more preferred demand side resources are available to meet these needs, SCE's LCR needs will be reduced toward the minimum authorized procurement level.

In various other dockets, we have established programs to promote the development of cost-effective energy efficiency and demand response resources. In order to ensure these resources will best be available to meet LCR needs, DRA recommends that SCE should be directed to work with the ISO to determine a

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[222] RT 628-629.

[223] RT 628.

[224] RT 612.

priority-ordered listing of the most electrically beneficial locations for preferred resources deployment.[225] We agree and will require SCE to do so.

Cushnie testified that before SCE undertakes any procurement method, it would take into account updated load forecasts and all available current information.[226] Thus, he recommends not locking down all the assumptions to use for LCR procurement at this time.[227] We agree with this approach. We have set minimum and maximum LCR procurement levels herein. Within this range, SCE will need to consider a variety of issues. These issues include (but are not necessarily limited to) effectiveness of siting, changes in load forecasts, potential cost-effective transmission upgrades, availability of SONGS and other existing resources, and potential market power of bidders. Within the parameters we set today, we will allow SCE managerial discretion to seek the best mix of resources. However, as set forth below, Energy Division will review SCE's procurement in advance, and SCE will need to file an application for approval of its procurement contracts.

One specific consideration is that the requirement to procure at least 50 MW of energy storage resources may provide energy storage providers with market power, to the detriment of ratepayers. TURN recommends allowing SCE to "invoke a price circuit-breaker for storage procurement if storage providers cannot provide resources that help meet local reliability at a reasonable price."[228] We agree. While we see considerable value in pursuing the experiment to

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[225] DRA Opening Brief at 30.

[226] RT 757-758.

[227] RT 760.

[228] TURN Opening Comments on Proposed Decision, p. 4.

procure energy storage resources, we do not intend that SCE be required to sign contracts from energy storage suppliers at all costs. In its application to implement this decision, SCE shall present the required contracts for energy storage resources to the Commission for approval, or have the burden to show that it should procure less than 50 MW because the bids it received were unreasonable.

CEJA and DRA urge the Commission to consider OTC plants that comply with SWRCB Track 2 policy (90+% reduction in water usage) without retiring as potential resources to meet SCE's local procurement needs.[229] Such plants may provide SCE with additional capacity options and potentially lower costs to ratepayers. We find that it is reasonable for SCE to consider retrofits to existing OTC plants, assumed retired in the ISO studies, in its procurement process. SCE may negotiate with existing OTC plant owners, either through an RFO or consistent with § 454.6, to finance retrofits that will reduce these plants' environmental harm sufficiently to be in compliance with SWRCB policy. Any proposed retrofit of an OTC facility shall compete with other least cost/best fit options.

7.3.2. Energy Division Review of SCE Procurement Plan

SCE seeks flexibility to choose the exact circumstances and timing under which it would utilize an RFO process or a bilateral contract negotiation in its LCR solicitation process, including parallel use of both methods. We agree with SCE that it is difficult in advance to know which method would be most advantageous to ratepayers, and that SCE is in the best position to administer

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[229] CEJA Opening Comments on Proposed Decision, p. 7. DRA Reply Comments on Proposed Decision, p. 2.

this process. We will allow SCE the flexibility it seeks, subject to review of its procurement plan by Energy Division and a subsequent Commission application.[230]

SCE shall provide its procurement plan for all required and authorized resources in the LA Basin and Big Creek/Ventura local areas to Energy Division no later than 150 days after the effective date of this decision. SCE may provide parts of its procurement plan to Energy Division earlier than 150 days. Specifically, we encourage SCE to present its plan for procurement of up to 1200 MW of gas-fired generation in the LA Basin and up to 290 MW of gas-fired generation in the Big Creek/Ventura local area earlier than 150 days. Due to the long lead time for these particular resources, it is imperative that SCE begin the procurement process (including Energy Division review) as soon as possible.

The procurement plan(s) shall include all of the following:

- A list of all applicable rules and statutes impacting the plan;
- A detailed description of how it intends to procure resources, specifying the structure of any RFO or alternative procurement process and related timelines;
- A methodology for determining least cost/ best fit that includes evaluating and quantifying performance characteristics that vary among resource type (e.g. time to start, output at various times, variable cost, effectiveness in meeting contingencies, etc.);
- What type of price benchmark will be used in determining cost-effectiveness for resources;

[230] Nothing in this decision exempts SCE from previously adopted Commission rules on RFOs in D.07-12-052 and elsewhere.

- An explanation for each resource type indicating whether modifications will be made to existing programs or if a new approach will be utilized;
- A methodology for determining peak capacity for resources for which there is not a currently approved methodology for determining Net Qualifying Capacity; and
- A methodology for determining other reliability capabilities (e.g. voltage support) for resources for which there is not a currently approved methodology for determining these capabilities

We have reviewed the comments of parties filed in response to the September 7, 2012 energy storage/long-term procurement workshop. Based on those comments and the overall record in this proceeding, any RFO should include the following elements:

a) The resource must meet the identified reliability constraint identified by the California ISO;

b) The resource must be demonstrably incremental to the assumptions used in the California ISO studies, to ensure that a given resource is not double counted;

c) The consideration of costs and benefits must be adjusted by their relative effectiveness factor at meeting the California ISO identified constraint;

d) A requirement that resources offer the performance characteristics needed to be eligible to count as local RA capacity;

e) No provisions specifically or implicitly excluding any resource from the bidding process due to resource type (except as authorized through this decision);

f) No provision limiting bids to any specific contract length;

g) Provisions designed to be consistent with the Loading Order approved by the Commission in the Energy Action Plan and to pursue all cost-effective preferred resources in meeting local capacity needs;

h) Provisions designed to minimize costs to ratepayers by procuring the most cost-effective resources;

i) A reasonable method designed to procure local capacity requirement amounts at or within the levels authorized or required in this decision, not counting amounts procured through cost-of-service contracts;

j) An assessment of projected greenhouse gas emissions as part of the cost/benefit analysis;

k) A method to consider flexibility of resources without a requirement that only flexible resources be considered; and

l) Use of the most up-to-date effectiveness ratings.

SCE shall not begin its public solicitation process until Energy Division determines in writing that SCE has complied with the provisions of this Decision. Separate Energy Division approvals are needed for the procurement plan and any request for offers. Because the process for soliciting gas-fired capacity may be simpler than for other capacity, Energy Division may provide that the gas-fired capacity portion of SCE's procurement plan can go forward first. The determination of the Energy Division shall be final.

7.3.3. SCE Application

SCE estimates that it would take anywhere from one to two years after today's decision before SCE can submit an application to the Commission with final LCR procurement contracts for Commission approval, after procurement solicitations, bilateral negotiations and studies for preferred resources.[231] At that

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[231] RT 719-720; 733-735.

time, SCE witness Cushnie foresees that "parties may choose to challenge the resources we're proposing to utilize to meet the LCR need."[232] In addition, he agrees that SCE would not object if a party wanted to assert that there were other preferred Loading Order resources that were available to SCE on a cost-effective basis that SCE failed to incorporate.

All contracts stemming from the LCR procurement authorization we establish today shall be brought to the Commission for approval in a single application for the LA basin local area and a single application for the Big Creek/Ventura local area (these applications may be combined if SCE chooses). Under SCE's schedule, the applications will be forthcoming sometime in late 2014. However, it is not self-evident why this process should take this amount of time. We expect that SCE's applications could be filed earlier than late 2014. Given the likely 7 to 9 year procurement process for gas-fired resources, we implore SCE to file its applications as soon as practical.

In its applications, SCE shall show:

- Cost-effectiveness;
- Consistency with the Loading Order, including a demonstration that it has identified each preferred resource and assessed the availability, economics, viability and effectiveness of that supply in meeting the LCR need;
- Procurement of between 215 and 290 MW to meet local capacity requirements in the Big Creek/Ventura local reliability area;
- Procurement of between 1400 and 1800 MW to meet local capacity requirements in the Los Angeles local reliability

[232] RT 758.

area (including specific provisions for conventional gas-fired and energy storage resources);

- For bilateral contracts negotiated under § 454.6, that the project will provide electricity at the cost of generation, including a reasonable return on the investment and the costs of financing the project; and
- A demonstration of technological neutrality, so that no resource was arbitrarily or unfairly prevented from bidding "or winning" in SCE's solicitation process, except as authorized through this decision. To the extent that the availability, viability and effectiveness of resources higher in the Loading Order are comparable to fossil-fueled resources, SCE shall show that it has contracted with these preferred resources first.

8. Flexible Capacity

The ISO recommends that any capacity to fill LCR needs "should have flexibility characteristics similar to the OTC generation" that needs to be replaced.[233] ISO witness Rothleder testified that flexible resources should:

> [p]rovide dispatch flexibility between minimum and maximum operating level[s]…can be used to respond to quick changes in load and variations of generation from renewable resources…can provide ancillary services…have inertia or governor control to respond to changes in frequency and a faster start, to respond more quickly when needed.[234]

Rothleder further testified that LCR resources would also need to meet other attributes of flexible conventional generation including "voltage support, flexibility, frequency response, sustained energy supply, reliable responsiveness,

[233] Exhibit ISO-1 (Sparks) at 17.

[234] Exhibit ISO-4 (Rothleder) at 8-9.

no significant use limitations and the ability to provide energy regulation, operating reserves and load following."[235]

SCE believes that all resources that have high NQC ratings -- as determined through the Commission's RA proceedings -- have the potential to meet local area needs (although some are more effective than others). SCE witness Minick testified: "In reality, an LCR resource doesn't need to have flexibility. They could be a baseload resource at a certain location and meet LCR requirements. But, it would be very nice from an operational perspective to have flexibility."[236] SCE witness Cushnie testified that "you might not want to have very stringent standards [for flexibility] in your solicitations" and SCE "can then look at various permutations of resource mixes including preferred resources."[237]

IEP recommends that the Commission wait for the completion of studies by the ISO necessary to determine the need for, and the preferred characteristics of, flexible resources before authorizing specific procurement of flexible resources.[238] EnerNOC believes that the Commission must define flexible attributes before requiring such attributes to be procured for LCR purposes.[239] EnerNOC contends that there are demand resources that provide several operational characteristics that the ISO considers in its description of flexibility.[240]

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235 Exhibit ISO-4 (Rothleder) at 8-9.

236 RT 972-973.

237 RT 696-697.

238 IEP Opening Brief at 10-11.

239 EnerNOC Opening Brief at 22.

240 Exhibit EnerNOC-2 (Huffman) at II-1 – II-6.

TURN does not believe that it is important to explicitly incorporate flexible capacity attributes into the LCR procurement process, because it is a serious challenge to establish specific values for different dimensions of flexibility. Further, TURN contends that new combined cycle plants and combustion turbines likely to bid into RFOs will possess tremendous flexibility, thus likely leading to procurement of flexible resources even without any explicit requirement.[241]

CEJA recommends that the Commission not limit potential procurement to resources that meet the ISO's flexibility definition, as LCR procurement in RA proceedings has never been equated with flexible capacity. CEJA points out that the ISO's modeling in R.10-05-006 (which is in the record of this proceeding) showed no flexibility need for 2020.[242]

WEM recommends that the Commission consider that various preferred resources (including demand side resources) should be able to provide certain flexibility characteristics. WEM recommends that the Commission establish final flexibility needs after completion of the ISO's flexibility analysis in Track 2.[243]

8.1. Discussion

SCE will be starting a procurement process as a result of this decision. In procuring resources, SCE will be able to determine what flexibility components various resources contain. At this time there is considerable uncertainty in both the types and quantities of flexible resources that may be needed to balance future resource needs. Preliminary ISO studies indicated a need with all OTC

241 TURN Opening Brief at 19-20.

242 CEJA Opening Brief at 51.

243 WEM Opening Brief at 6.

resources compliant of 0 MW in the mid load scenarios, but a need of 4600 MW in the high load trajectory scenario.[244] The combined cycle gas turbine resources added from the local areas to a subsequent run of the renewable integration modeling had high capacity factors, over 75%, while combustion turbines had capacity factors close to 13%.[245] These results indicate that while flexibility is an important consideration, it is unclear what exact attributes and blend of flexible versus baseload resources are needed.

The issue of flexibility and determination of flexible attributes for LCR needs is also currently being considered in the RA proceeding, R.11-10-023. A decision in the RA proceeding is expected in the first half of 2013. There is no need to make a determination on flexibility issues in this track of this proceeding. There is also an insufficient record at this time. We cannot currently define flexibility for LCR procurement purposes with any specificity or determine what flexible attributes should or should not be procured by SCE.

Therefore, we will not require SCE to take into account any particular flexible attributes in its procurement process, and will not make acquisition of any flexible attributes a condition of approval of SCE's forthcoming LCR procurement application. However, SCE should identify any known flexible attributes or characteristics of resources bid into its RFO or considered in bilateral negotiations. To the extent that SCE can obtain flexibility in LCR contracts consistent with other requirements, it should do so.

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244 Exhibit ISO-4 (Rothleder) at 2, 11-19.

245 Exhibit ISO-4 (Rothleder) at 5, 7-20.

9. Cost Allocation Methodology (CAM)

9.1. CAM Overview

In D.04-12-048, the Commission adopted the IOUs' 2004 long-term procurement plans. As part of its efforts to ensure a long-term, reliable energy supply for California customers, the Commission authorized the IOUs to recover stranded costs associated with new PPAs and utility-owned generation (UOG) from all customers, with the goal of providing "the need for reasonable certainty of rate recovery."[246] By doing so, the Commission sought to address utilities' concern that they could end up over-procuring resources and incurring the associated stranded costs given the potential for a significant portion of their load to take service from a different electric service provider (ESP).

D.04-12-048 did not specify the actual implementation mechanism for recovering these costs. D.06-07-029 in the 2006 long-term procurement proceeding decision adopted the CAM, which allows the costs and benefits of new generation to be shared by all benefiting customers in an IOU's service territory. The Commission designated IOUs to procure the new generation through long-term PPAs, and the rights to the capacity were allocated among all LSEs in the IOU's service territory. The allocated capacity rights can be applied toward each LSE's RA requirements. In exchange for those benefits, the LSEs' customers – termed "benefitting customers" – pay for the net cost of the capacity.[247]

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[246] D.04-12-048, Conclusion of Law 14.

[247] The energy and capacity components of the newly acquired generation are disaggregated. The net capacity cost is calculated as the net of the total cost of the contract minus the energy revenues associated with the dispatch of the contract. The

Footnote continued on next page

The basic framework for the CAM was set forth in D.06-07-029 as follows: The IOU would contract with an Independent Evaluator to oversee an RFO for new resource contracts. At the conclusion of the RFO, the IOU would sign a long-term contract with the generator of a new resource. The IOU would seek contract approval from the Commission, and at that time, select whether or not it intends for the CAM to apply to the contract. The Commission's decision on the IOU's application determines the applicable CAM based on allocating the appropriate net capacity costs to all benefiting customers in the IOU service area.[248] The IOU would then request Commission approval to conduct periodic auctions with an Independent Evaluator for the energy rights of the resource, essentially selling the tolling right – the energy component – and retaining the RA benefit, which it then shares with all customers paying for the capacity.[249] D.06-07-029 at 26 explained that "benefiting customers" referred to all bundled service, direct access (DA), Community Choice Aggregator (CCA) customers and "other customers who are located within a utility distribution service territory but take service from a local publicly-owned utility subsequent to the date the new generation goes into service." D.06-07-029 at 26 (footnote 21) specified that current customers of publicly-owned utilities were exempt from the CAM.

Subsequent decisions clarified and amended the CAM. D.07-09-044 presented in greater depth the procedures for the energy auctions. The procedures established a backstop for the auctions. Should an auction fail to

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non-bypassable change levied is for the net capacity cost only, and the non-IOU LSEs maintain the ability to manage their energy purchases.

248 D.06-07-029 at 52-53.

249 D.06-07-029 at 31-32.

produce a successful bid for the energy products, the capacity costs would be calculated via a specified alternative mechanism.[250] D.08-09-012 set forth that customer generation departing load was exempt from the CAM. That decision clarified that only large municipalizations were subject to the CAM, while exempting other classes of municipal departing load.

Senate Bill 695, signed into law in 2009, requires that the net capacity costs of new generation resources deemed "needed to meet system or local area reliability needs for the benefit of all customers in the electrical corporation's distribution service territory" must be passed on to bundled service customers, DA and CCA customers.[251] In order to align the CAM with the requirements of SB 695, D.11-05-005 did the following:

(1) Removed the right for the utility to elect or not elect CAM treatment for a resource that meets the conditions of the statues;

(2) Widened the scope of the CAM to apply to utility-owned generation resources, and

(3) Extended the duration of CAM treatment to match the duration of the underlying contract, eliminating the 10-year cap.[252]

SB 790 in 2011 codified the Commission requirement that the costs to ratepayers for CAM procurement are allocated to ratepayers in a "fair and equitable" manner.[253]

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[250] *See* D.07-09-044, Appendix A for specifics relating to the Joint Parties' Proposal, the alternative to the auction mechanism.

[251] Stats. 2009, ch. 337.

[252] D.11-05-005 reaffirmed that SB 695 does not require any revisions to the determinations made in D.08-09-012 regarding non-bypassable charges and the CAM process.

The Scoping Memo posed three questions related to the CAM:

(1) How should the costs of any additional local reliability needs be allocated among LSEs in light of the CAM?

(2) Should the CAM be modified at this time? and

(3) Should LSEs be able to opt-out of the CAM, and if so, what should the requirements be to permit such an opt-out?

In addition to the questions posed by the Commission, SSJID raised specific questions regarding its classification as a large municipalization and the CAM's application in its particular case. SSJID also questioned whether the CAM applies to municipal departing load in general.

9.2. Allocating Costs of Local Reliability Needs Among LSEs in Light of the CAM

The three IOUs, TURN and DRA all assert that the CAM should apply to all generation authorized in Track 1,[254] and net capacity costs should be allocated to all benefitting customers, including bundled service, DA, and CCA customers.[255] DRA explains that "since LCR resources would provide reliability benefits to all customers, the net capacity costs should similarly be allocated to all customers."[256]

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253 Stats. 2011, ch. 599.

254 Nothing in this decision is intended to imply or state that the CAM applies to bundled procurement.

255 *See* Exhibit SDG&E-2 (Anderson) at 9; Exhibit SCE -2 (Cabbell/Cushnie/Minick/Silsbee) at 20-23; Exhibit TURN-2 (Woodruff) at 16; Exhibit DRA-5 (Ciupagea) at 1.

256 Exhibit DRA-5 (Ciupagea) at 1.

AReM asserts that the Commission's goal should be to minimize CAM procurement.[257] AReM testified that it is only fair to allocate CAM costs when the need creating the costs can be attributed to all customers, and not solely to IOU bundled load. To that end, AReM maintains that the Commission must evaluate the characteristics of the load served by the IOUs versus the characteristics of the load served by the other LSEs in the IOU service area to determine the different rates at which they grow. If this analysis finds that bundled customer load is driving the peak or decreasing the system load factor, then AReM contends bundled customers should pay for the resources necessary to meet that need.

Further, AReM states that per its obligation under § 454.5, the Commission should ensure that CAM procurement is needed to meet a specified reliability need as defined by § 365.1(c)(2)(B). AReM contends that this means that the reliability need must be incremental to the needs associated with LSEs. For example, AReM argues that if a generation plant that "primarily" served bundled load retired or shut down and the IOU filed for approval for CAM procurement to replace the unit, the Commission should reject this application. According to AReM, while "incidental reliability benefits [from the replacement unit] would likely accrue to '*all*' customers, bundled customers would benefit disproportionately more, because the customers of other LSEs would subsidize their '*unmet needs*.'[258] Therefore, AReM reasons, CAM procurement should not be authorized.

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[257] Exhibit AReM-1 (Mara) at 5, 20.

[258] Exhibit AReM-1 (Mara) at 28.

AReM sets forth a two-step proposal for the Commission to determine whether a particular CAM project should be approved: (1) calculate the MWs of unmet need, and identify what portion of the unmet need is driven by the bundled load, and (2) if MWs of unmet need exist and are attributable to all benefiting customers in the service area, then AReM propose six criteria to ascertain whether the CAM should be applied in the particular case.[259] The proposed criteria are:

1. The IOU's Application requests, as required by § 365.1(c)(2)(A), the following: (i) approval for a specific contract with a third party to procure generation resources; or (ii) an order to procure a specific UOG resource.
2. The Commission has previously determined that the MWs in the Application may be subject to CAM procurement.
3. The Commission determines that the project identified in the Application fulfill an unmet need that is not attributable to any individual LSE.
4. The Commission determines that the project identified in the Application is required by the ISO to meet a specific System or Local RA need that cannot be reasonably met by other existing resources, demand response, energy efficiency or other alternatives and is required to be operational as of the timeline proposed in the IOU's Application to avoid degrading grid reliability.
5. The Commission determines that the project identified in the Application benefits all customers within the IOU's

[259] AReM proposes this criteria as a less restrictive alternative to a "benefits test" as a means of determining when to authorize CAM procurement per § 365.1(c)(2)(A). SDG&E and DRA both recommend that the Commission explore creating a defined "benefits test" for CAM procurement. *See* Exhibit SDG&E-1 (Anderson) at 10-11 and Exhibit DRA-5 (Ciupagea) at 4. SDG&E suggests that "the Commission should find that benefitting parties are those parties that have load in the reliability area." Exhibit SDG&E-1 (Anderson) at 11.

service territory, including DA and CCA customers, by the way in which it meets the reliability needs specified by the ISO, as required by § 365.1(c)(2)(B).

6. Local RA projects in an IOU's Local RA Area provide comparable reliability benefits, as specified by the ISO, to all customers located in the entire IOU's service area, as required by §§ 365.1(c)(2)(A), 365.1(c)(2)(B), and 366.2 (g). Projects that provide the specified reliability benefits primarily to customers located within the Local RA Area where the project will be developed must be rejected as inconsistent with the statutes noted.[260]

The three IOUs and DRA oppose AReM's cost causation principle, stating that LCR resources would provide reliability benefits to all customers, and thus, the net capacity costs should similarly be allocated to all customers.[261]

SDG&E proposes that the Commission explicitly adopt a rebuttable presumption that the net capacity costs of generation resources authorized to meet system and local reliability requirements should be allocated via the CAM to all customers within the IOU's service territory.[262] SDG&E acknowledges that while CAM procurement must receive careful consideration, minimizing CAM should not be the overriding consideration. As long as state policies and interests are served through utility procurements that provide benefits beyond the IOU's bundled customers, the Commission should allocate the costs via the

[260] Exhibit AReM-1 (Mara) at 30-31.

[261] Id. at 8-9; Exhibit SCE-2 (Cushnie) at 27-28; Exhibit PG&E-1 (Frazier-Hampton/Martyn/Williams) at 8 (PG&E asserts that if AReM's cost causation proposal is accepted, then DA and CCA providers should be willing to agree to submit procurement plans to the Commission alongside IOUs); Exhibit DRA-5 (Ciupagea) at 1-2.

[262] Exhibit SDG&E-2 (Anderson) at 6.

CAM to all benefitting customers.[263] SDG&E also takes issue with what it perceives as AReM presupposing that utility bundled load drives growth in peak demand and decrease in system load factors, when these assumptions are debatable. SDG&E states that AReM fails to address the complicated reality that there is no "objective formula that can be devised for quantifying and allocating reliability benefits among different customer groups."[264]

SCE states that the costs of any SCE procurement to meet system reliability needs must be "fully recoverable and allocated appropriately" to DA and CCA customers via the CAM.[265] SCE asserts that it would prefer not to procure beyond its bundled customers for system reliability,[266] and maintains that it will not procure system reliability resources unless "all benefitting customers pay their fair share."[267]

PG&E recommends allocating the costs of LCR procurement in Track 1 to "all customers in the service area where LCR resources are added, whether bundled, DA, or CCA customers."[268] PG&E believes that LCR procurement in the LA basin should be allocated to all benefiting customers in SCE's service territory, but not to any customers in PG&E's service territory.[269]

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[263] Exhibit SDG&E-2 (Anderson) at 1-3.

[264] Exhibit SDG&E-2 (Anderson) at 8.

[265] Exhibit SCE-1 (Cushnie) at 25.

[266] Exhibit SCE-1 (Cushnie) at 21-22.

[267] Exhibit SCE-1 (Cushnie) at 21.

[268] Exhibit PG&E-1 (Frazier-Hampton/Martyn/Williams) at 6.

[269] Exhibit PG&E-1 (Frazier-Hampton/Martyn/Williams) at 4.

TURN asserts that "the most reliable means of getting any needed new capacity built is for Edison take on the responsibility of contracting for such capacity and allocate the costs to all benefit[ting] customers via the CAM."[270] TURN states that AReM's suggestions for CAM implementation would result in DA and CCA customers paying for less than a proportionate share of the reliability costs, and should thus, be rejected.[271]

9.3. Discussion

Section 365.1(c)(2)(A)-(B) holds that in instances when the Commission determines that new generation is needed to meet local or system area reliability needs for the benefit of all customers in the IOU's service area, the net capacity costs for the new capacity shall be allocated in a fair and equitable manner to all benefiting customers, including DA, CCA and bundled load. Simply put, each customer must pay their fair share for the benefits that flow to them from the new generation for the full life of the asset.[272]

AReM's driving peak/decreasing load proposal fails to recognize the interrelated nature of the electric system and the reality that some individual customers of ESPs, CCAs and IOUs have static load profiles, while others are driving the need for new resources. In addition, the retirement of existing resources creates the need for new resources to serve customers that may not be driving increases. Therefore, we continue the current Commission policy of allocating CAM costs and benefits at the IOU service area level.

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[270] Exhibit TURN-1 (Woodruff) at; Exhibit TURN-2 (Woodruff) at 16.

[271] Exhibit TURN-2 (Woodruff) at 4.

[272] We note that SB 695 relieves the IOUs of limiting CAM treatment to 10-year contracts.

In addition, we do not adopt AReM's two-step/six criteria framework. AReM's approach imposes additional requirements designed to limit CAM allocation, and appears to create a precise determination of "benefitting customers." However, precision is not the same as fairness. The Commission's previously adopted criteria fairly apportion costs to customers as envisioned by past Commission and the legislature actions. While creating more complexity, nothing in AReM's proposal improves on the fairness of the current allocation. Thus, the costs of local reliability needs shall continue to be allocated in accordance with previous Commission decisions.

9.4. Should the CAM be Modified at This Time?

AReM proposes several further modifications to the CAM, including changes to energy auction terms and the adopted program's proxy calculation. AReM suggests that the Commission make the current five-year maximum ceiling on energy auctions products to a five-year minimum floor. AReM contends that longer term tolling would more accurately reflect "the incremental hedging value of the PPA."[273]

AReM also opines that the net capacity cost calculation from the adopted program should be changed to better reflect the increased ancillary service value and value of "other products and services" provided by the new PPAs or UOG plants beyond non-spinning reserves.[274] In addition, AReM proposes that the Commission modify the adopted program in order to account for the options value associated with a long-term tolling contract. By failing to incorporate this

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[273] Exhibit AReM-1 (Fulmer) at 39.

[274] Exhibit AReM-1 (Fulmer) at 39-41.

value, AReM contends, the current CAM framework "ignores one of the primary driver of PPA cost: the opportunity value of purchasing energy with agreed-upon terms in a market characterized by energy price volatility.[275]

AReM also supports a levelized annual revenue requirement for UOG plants in order to account for the reality the imputed capacity costs of a UOG generating plant changes over time as the plant is depreciated.[276] Finally, AReM asserts that the CAM should be capped, as a "backstop to ensure reasonable results."[277] AReM recommends that the Commission convenes workshops to discuss the details of implementing some of their suggested design modifications.

SDG&E believes that the current auction mechanism is administratively unwieldy and not necessarily conducive to efficient capacity costs.[278] SDG&E supports the use of the adopted program[279] as an alternative to the use of an energy auction to determine the net capacity costs for CAM resources. SDG&E suggests that the Commission eliminate the IOUs' obligation to auction the right to the energy, unless the Commission directs otherwise; toward that end, SDG&E opines that the Commission should convene workshops to construct a permanent alternative to energy auctions.[280] In addition, SDG&E specifically

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[275] Exhibit AReM-1 (Fulmer) at 42-43.

[276] Exhibit AReM-1 (Fulmer) at 44.

[277] Exhibit AReM-1 (Fulmer) at 48.

[278] Exhibit SDG&E-1 (Anderson) at 10-11. TURN, on the other hand, expressed its support for CAM's current energy auction approach. Exhibit TURN-2 (Woodruff) at 3.

[279] The adopted program refers to the current CAM program, adopted in D.06-07-029, and amended in subsequent decisions as previously laid out in this decision.

[280] Exhibit SDG&E-2 (Anderson) at 10.

rejects AReM's proposal to amend the adopted program to include all major ancillary service products currently available in the ISO market, levelize the annual revenue requirement for utility-owned generation, and cap the CAM.[281]

DRA supports SDG&E's proposal to change the energy auctions. DRA encourages the Commission to convene workshops to explore possible modifications to the net capacity cost allocation, the valuation for energy and ancillary services and pursue the reduction of capacity costs for all parties.[282]

The three IOUs and TURN oppose AReM's proposal to incorporate ancillary services in calculating energy dispatch value.[283] SCE and PG&E align with SDG&E in objecting a levelized annual revenue requirement,[284] while all three IOUs and TURN expressly object to AReM's proposal to cap the CAM.[285]

We reject the proposed cap on CAM. We find that AReM's proposal to levelize the annual revenue requirement obviates the plain language of § 365.1(c)(2)(C), which states that the net capacity costs shall be determined by "subtracting the energy and ancillary services value of the resource from the total costs paid by the electrical corporation pursuant to a contract with a third party or the annual revenue requirement for the resource if the electrical corporation

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281 SDG&E-2 (Anderson) at 6-12.

282 Exhibit DRA-5 (Ciupagea) at 4.

283 SDG&E-2 (Anderson) at 6-12; Exhibit SCE-2 (Cushnie) at Exhibit PG&E-1 (Frazier-Hampton/Martyn/Williams) at 9-10, Exhibit TURN-2 (Woodruff) at 9.

284 Exhibit SCE-2 (Cushnie) at 37; Exhibit PG&E-1 (Frazier-Hampton/Martyn/Williams) at 10.

285 Exhibit SCE-2 (Cushnie) at 32, 37-38; Exhibit PG&E-1 (Frazier-Hampton/Martyn/Williams) at 11; Exhibit TURN-2 (Woodruff) at 8-9 (TURN contends that imposes a cap on CAM without simultaneously imposing a floor would be discriminatory).

directly owns the resource." (emphasis added.) Once the CAM contract has lapsed, bundled customers would overpay for the depreciated value of the generating asset capacity, while non-IOU customers would have paid less than their fair share of the full value of the asset's capacity value. Further, the proposal to cap the CAM contradicts its central purpose: apportioning system and local reliability costs to all benefiting customers in an IOU service area so that each benefitting customer pays their fair share.

We have stated an openness to revisit the energy auction mechanism adopted in D.07-09-044.[286] Toward that end, we appreciate the suggestions from parties in the current proceeding to consider improvements toward the current auction mechanism structure, including valuing net capacity costs. The record, however, fails to provide an adequate basis upon which to comprehensively consider and adopt any potential changes to the auction mechanism. We may consider taking a more focused look at these issues in the future.

9.5. CAM Opt-Out

In D.06-07-029, the Commission found the concept of a CAM opt-out mechanism for LSEs appealing, upon the demonstration that an LSE is fully resourced with new generation for ten years forward. However, D.06-07-029 stated "the reality is that we have no viable enforcement program or mechanism for doing so," such as a "multi-year RA program where an LSE could demonstrate it is fully resourced for the next four or 10 years."

AReM strongly supports an LSE opt-out, asserting that it is essential to maintaining market choice. AReM's opt-out would function as follows. Once

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[286] For example, *see* D.11-05-005.

the Commission determines unmet need subject to the CAM, an ESP or CCA would have the option to request an opt-out from the CAM. The LSE has until the IOUs submit any proposed CAM projects to request an opt-out. In order to qualify for an opt-out, an LSE would make a showing to the Commission that it has procured adequate generation resources for a five-year period.

AReM proposes three types of out-out: (1) Load Ratio Share Opt-Out; (2) Load-Based Opt-Out; and (3) Customer-Based Opt-Out, which are described in detail in its testimony.[287] The three IOUs, TURN and DRA all categorically reject AReM's opt-out proposals.[288] Each asserts that AReM's proposed five-year forward contract term showing is insufficient time to procure and finance new generation resources given the reality of long lead time for building new generation.[289] SDG&E contends that a CAM opt-out would encourage LSE free riding at the expense of utility ratepayers.[290] SCE asserts that a CAM opt out stands in direct contrast to the Legislature's intent to pass along costs to all benefiting customers in a fair and equitable manner.[291] PG&E points out that keeping track of all the potential LSEs who choose to opt out of the CAM via one of the three ways proposed by AReM will result in high administrative costs.[292]

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[287] *See* Exhibit AReM-1 (Mara), starting at 57.

[288] Exhibit SDG&E-2 (Anderson) at 13-14; Exhibit SCE-2 (Cushnie) at 38; Exhibit PG&E-1 (Frazier-Hampton/Martyn/Williams) at 12; Exhibit TURN-2 (Woodruff) at 6-7; Exhibit DRA-5 (Ciupagea) at 5.

[289] Exhibit DRA-5 (Ciupagea) at 5.

[290] Exhibit SDG&E-2 (Anderson) at 12.

[291] Exhibit SCE-2 (Cushnie) at 39-40, which excerpts § 365.1(c)(2)(A)-(B).

[292] Exhibit PG&E-1 (Frazier-Hampton/Martyn/Williams) at 12.

TURN asserts that AReM's proposal would result in DA and CCA customers paying for less than a proportionate share of the costs of local reliability needs, with virtually no responsibility for new capacity needed to meet load reliably.[293] DRA argues that it is unclear how AReM's proposal would be enforceable to "ensure that 'there will be no free riders' vis-à-vis the cost of capacity of new generation,"[294] and disagrees with AReM that only non-IOU LSEs should be allowed to opt out of the CAM.[295]

9.6. Discussion

The issue of a CAM opt-out is complex. AReM has properly raised legitimate questions regarding equity of the current CAM structure. However, while AReM's detailed proposal of a potential opt-out structure is helpful, it is unclear how its five-year contract term/project life requirement would adequately ensure investment in new resources. Further, it is not at all clear that a CAM opt-out could be implemented without undue administrative burden. After considering comments from parties, we find the record insufficient to resolve these questions, and therefore do not adopt an opt-out at this time.

We will not rule out consideration of a CAM opt-out at a future date. However, we have considered parties' positions on more than one occasion, and declined to adopt a CAM opt-out. Therefore, we are disinclined to relitigate this issue in the future unless all or nearly all impacted parties can agree on a specific, detailed and implementable proposal, or there are significant changed circumstances.

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[293] Exhibit TURN-2 (Woodruff) at 7.

[294] Exhibit DRA-5 (Ciupagea) at 5, quoting Exhibit AReM-1 (Mara) at 19.

[295] Exhibit DRA-5 (Ciupagea) at 5.

9.7. SSJID Proposal

SSJID asserts that it should be exempt from the CAM. Specifically, SSJID recommends the Commission should "exempt all existing and future [publicly-owned utility departing load], including large municipalizations, from CAM responsibility."[296]

PG&E argues that SSJID should be subject to the CAM. PG&E asserts that the Commission has already decided in D.08-09-012 at 27-30 that the CAM applies to all large municipalization departing loads, and that SSJID fits into the Commission's stipulated definition of a large municipalization.[297]

SSJID's argument against CAM application is that: (1) SSJID's Municipal Departing Load (MDL) should not be classified as a large municipalization as defined by the Commission in D.08-09-012; (2) California law does not require that Public-Owned Utilities (POUs) or MDL of any size (including large) be included as "benefiting customers" for the purposes of the CAM; (3) POUs do not present the same capacity procurement risks as DA or CCA loads; (4) POU customers may not be able to RA credits allocated under CAM; and (5) the Commission's alternative methodology for allocating RA costs and benefits to large municipalizations is an approximation and is impractical.[298]

Most of the matters raised by SSJID were addressed in D.08-09-012 and will not be relitigated here. Regarding the definition of "large municipalization," D.08-09-012 at 26-27 stated:

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[296] Exhibit SSJID-1 (Shields) at 4.

[297] Exhibit PG&E-2 (Rubin) at 2.

[298] Exhibit SSJID-1 (Shields) at 3-4.

> While there is no precise measure of what constitutes a "large municipalization," in the context of this decision, we are defining "large municipalization" as any portion of an IOU's service territory that has been taken control of or annexed by a POU where the amount of load departing the IOUs' service territories due to the municipalization is of such a large magnitude that it cannot reasonably be assumed to have been reflected as part of the historical MDL trends used in developing the adopted LTPP load forecasts."

As indicated, D.08-09-012 did not specify the exact parameters for "large municipalization." It is not within the scope of this proceeding to determine whether SSJID is a large municipalization. SSJID has not convinced us that other issues it raised require any further action at this time.

10. Cost of Capital (COC)

SCE witness Hunt testified that SCE seeks Commission authorization to file a separate application to adjust its capital structure to take into account debt equivalence issues arising from additional PPAs.[299] Debt equivalence occurs when rating agencies determine that the capacity costs of PPAs are equivalent to debt for the IOUs because the payments cannot be avoided without defaulting on the PPA.

Hunt contends PPAs arising from this decision will create significant debt equivalents or debt equivalence on SCE's balance sheet that may need to be mitigated to preserve SCE's creditworthiness. Hunt estimates that SCE's 2013 debt equivalence will be about $2.5 billion, while LCR procurement contracts could increase that amount by $900 million to $2.9 billion.[300]

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[299] RT 834.

[300] Exhibit SCE-1 (Hunt) at 27.

DRA opposes SCE's request. DRA recommends that SCE should wait to have the Commission consider any changes in SCE's debt equivalence resulting from LCR procurement until the next COC proceeding. DRA asserts that since debt equivalence is only one of many credit risk drivers impacting SCE's credit rating, debt equivalence should be considered together with those other credit risk drivers.[301] TURN points out that the Commission has addressed this issue in several previous procurement-related proceedings and declined to approve the relief requested by the utility. TURN cites D.09-06-018 at 58, stating that "we will take action to address negative impacts on any utility's balance sheet or credit profile when warranted and necessary, and will do so in a manner consistent with the urgency of the matter."

SCE's capital structure is typically determined in its COC proceeding. On April 20, 2012, SCE filed its most recent COC application. SCE's next COC proceeding is expected in early 2015. SCE witness Hunt testified that the point at which SCE's procurement PPAs stemming from this order would be included in rating agencies' rating as debt equivalence is generally when energy deliveries begin under a contract.[302] Mr. Hunt also testified that to the extent that the contract will simply replace an expiring contract, Standard and Poor's rating agency will impute debt as though the future contract is a continuation of the existing contract.

SCE itself expects the process from today's decision to Commission-approved contracts to take about two years, or until late 2014. Any potential impact on SCE's COC will not commence until at least the time of the

301 Exhibit DRA-8 (Lasko) at 3.

302 RT 839.

Commission's decision on SCE's LCR procurement application, if not for several years afterwards.

We will not change our policy from D.09-06-018 and previous decisions. SCE should use its next COC application, or other venue for consideration of COC, to seek any changes it considers appropriate due to debt equivalence for the contracts foreseen from today's decision.

11. Motion of Megawatt Storage Farms (MSF)

On October 5, 2012 MSF filed a motion asking the Commission to rule that energy storage should be ranked first in the Loading Order. MSF argues that this proceeding is evaluating and deciding on quantities of resources to be procured, and that energy storage must be considered here. MSF notes that energy storage is not mentioned explicitly by name in the current Loading Order, and that it is impossible for the LTPP Proceeding to analyze or decide on procurements unless a decision is made on energy storage's ranking within the Loading Order.

MSF articulates several reasons why it contends energy storage should be first in the Loading Order. First, MSF contends that energy storage reduces natural gas needs for renewables integration. Second, MSF claims energy storage reduces natural gas needs for frequency regulation. Third, MSF argues that energy storage promotes energy efficiency by time shifting. Finally, because energy storage does not fit into other specified categories (these categories are entitled "new generation" and "fossil fuel, central station generation"), MSF contends energy storage is properly placed in the first category.

Several parties filed in opposition to MSF's motion. Opposing parties argue that the MSF motion is untimely, that energy storage issues are being considered in another proceeding, and that the Loading Order should not be modified in this proceeding.

The MSF motion is denied. In this decision, we establish a solicitation process for SCE to procure for long-term LCR needs. In this process, there will be opportunities for potential energy storage facilities to participate; we specifically require SCE's solicitation process to be technologically-neutral. Further, we require SCE to procure at least 50 MW of energy storage.

However, it is premature to consider where energy storage should be placed in the Loading Order. As MSF acknowledges and as discussed herein, we are considering issues related to energy storage in R.10-12-007. In that proceeding, it is possible (though not guaranteed) that the Commission will establish procurement targets for energy storage or otherwise provide a method to facilitate the development of energy storage technologies. At this time, no decisions have been made concerning the viability, cost-effectiveness or public interest nature of energy storage technologies in that docket. If and when such action is taken, the role of energy storage technologies in the procurement process can be considered.

We also note that, as discussed herein, the Loading Order was developed in a multi-agency process and is, in part, established in statute. We do not intend to unilaterally reconsider the multi-agency Energy Action Plan in this decision; certainly, we cannot alter a statute here.

12. Categorization, Need for Hearings and Assignment

The assigned Commissioner is Michel Peter Florio and the assigned Administrative Law Judge (ALJ) is David M. Gamson. ALJ Gamson is the Presiding Officer.

13. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on January 14, 2013, and reply comments were filed on January 22, 2013.

Based on comments, the PD has been modified as follows:

- The minimum procurement level for the LA Basin has been increased from 1050 MW to 1400 MW;
- The maximum procurement level for the LA Basin has been increased from 1500 MW to 1800 MW;
- For the LA Basin, SCE is now required to procure at least 150 MW of preferred resources (as opposed to no requirement in the PD);
- For the LA Basin, SCE may procure up to 600 MW of preferred resources (as opposed to an authorization of 250 -450 MW in the PD), subject to the overall 1800 MW cap;
- As with the PD, SCE is required to present contracts for at least 50 MW of energy storage resources in the LA Basin to the Commission for approval, or (in the revised PD) to have the burden of proof to show that it should procure less than 50 MW because the bids it received were unreasonable;
- The PD's authorization for SCE to procure up to 1519 MW of distributed generation (less amount already expected to be procured) in the LA Basin is deleted;
- The ISO Trajectory scenario is used as a starting point for forecasting LCR needs for the LA Basin (instead of the ISO Environmentally Constrained scenario sensitivity analysis in the PD). The ISO Trajectory scenario is adjusted to account for 100% of uncommitted energy efficiency and CHP forecasts by the CEC, and to account for a conservative forecast of 200 MW of demand response resources;
- SCE is now required to consider retrofits of a power plant cooling system undertaken to comply with State Water

Resources Control Board Statewide OTC Policy as a new resource in considering resources to meet its LCR needs;

- A footnote in the PD is modified to allow certain CHP resources to qualify as part of the 1000 to 1200 MW requirement for conventional gas-fired resources in the LA Basin;
- Clarification of the relationship between procurement requirements in this proceeding and Commission procurement decisions in the RPS docket;
- Clarifications to requirements for SCE's Procurement Plan (reviewed by Energy Division) and subsequent procurement Applications;
- Other minor changes and clarifications to the PD are made as appropriate;
- Various Findings of Fact, Conclusions of Law and Ordering Paragraphs are modified to effectuate the changes to the PD listed above.

Findings of Fact

1. It is reasonable for the Commission only to consider LCR forecasts by the ISO using renewable portfolio scenarios already in the record of R.10-05-006.

2. It is reasonable to use local capacity studies and power flow modeling from the ISO for LCR forecasting.

3. The ISO used demand forecasts provided by the CEC in its 2009 IEPR, which used 2009 demand forecast data. It is reasonable to use this data for LCR forecasting in this proceeding.

4. In the LA basin local area, the Alamitos, El Segundo, Huntington Beach, Redondo Beach power plants use OTC technology. Sixteen OTC units are required to comply with SCRWB regulations to substantially reduce water use before 2021. In total, these units currently have more than 4900 MW of capacity.

5. In the Big Creek/Ventura local area, the Ormond Beach and Mandalay power plants are OTC plants with four units which are required to comply with SWRCB regulations to substantially reduce water use before 2021. In total, these units currently have more than 2000 MW of capacity.

6. The ISO forecasted LCR needs 10 years into the future for the first time; these forecasts (like other forecasts) are subject to error due to input assumptions and significant changes in circumstances in the future.

7. Both under-procurement and over-procurement entail significant risks. Under-procurement entails risks of reliability problems and the impacts of mitigating such problems in a short timeframe. Over-procurement entails risks of excessive costs and unnecessary environmental degradation. It is not possible to quantify whether the risks of over- or under-procurement are greater.

8. It is reasonable to use the CEC's one-in-10-year load forecast, combined with the contingencies identified by the ISO, for the purpose of LCR forecasting in this proceeding.

9. It is reasonable to use the ISO's analysis of transmission for the purpose of LCR forecasting in this proceeding.

10. It is reasonable to assume that the OTC plants in the SCE territory required to comply with SWRCB regulations will comply through retirement or repowering consistent with the SWRCB schedule, for the purpose of LCR forecasting in this proceeding. However, no finding on this point is intended to apply to SONGS.

11. Each of the four RPS scenarios analyzed by the ISO contain a reasonable minimum level of energy efficiency from CEC forecasts which can be used for the purposes of determining LCR needs for the LA basin local reliability area.

12. The four RPS scenarios analyzed by the ISO do not include any uncommitted energy efficiency or uncommitted CHP resources analyzed by the CEC.

13. To the extent uncommitted energy efficiency and uncommitted CHP resources ultimately develop, they can be helpful in reducing overall net demand. However, these resources are not likely to be as effective in reducing LCR needs as repowered gas-fired resources at existing OTC locations. Reducing overall net demand reduces LCR needs.

14. A significant amount of what is categorized by the CEC as uncommitted energy efficiency is certain to occur because it is based on standards already adopted by the CPUC, the CEC and federal agencies.

15. In the ISO's Environmentally Constrained scenario sensitivity analysis, the impacts of uncommitted energy efficiency and uncommitted CHP significantly reduced LCR needs for the LA basin local reliability area compared to other ISO scenarios.

16. There will be more uncommitted energy efficiency available in the LA basin local reliability area than was included in the ISO Trajectory scenario. The ISO Environmentally Constrained scenario sensitivity analysis includes a reasonable level of uncommitted energy efficiency for the LA basin local reliability area.

17. There is at least 100 MW of demand response in the most effective locations now in the LA Basin (and 549 MW of total demand response resources now).

18. By 2020 it is likely that the actual amount of demand response resources available to reduce LCR needs in the LA Basin will be considerably more than 100 MW, and possibly closer to DRA and CEJA's estimates of around 1000 MW.

19. There will be more uncommitted CHP available in the LA basin local reliability area than was included in the ISO Trajectory scenario.

20. The ISO's Trajectory scenario includes a reasonable minimum level of distributed generation for the LA basin local reliability area for the purposes of determining the LCR need in this proceeding, except that it does not include a sufficient estimate for uncommitted CHP.

21. The ISO's Environmentally Constrained scenario sensitivity analysis includes a reasonable maximum level of uncommitted CHP for the LA basin local reliability area for the purposes of determining the LCR need in this proceeding.

22. In R.10-12-007, the Commission is considering multiple energy storage options to determine the cost-effectiveness of these potential resources. At this time there is not sufficient information to determine how much viable energy storage facilities will emerge between now and 2021 that can be used for local reliability purposes.

23. It is premature to consider a modification to the ISO local reliability need forecast for energy storage for the LA basin local area at this time.

24. It is reasonable to expect that some unidentified amount of energy storage resources will be available in the future, and it is likely that some amount of energy storage resources will be available to meet future LCR needs. It is unclear whether the costs of energy storage resources will be reasonable.

25. It is likely that some LCR procurement opportunities would be lost if there is a delay in approving a procurement process for the LA basin local reliability area and the Big Creek/Ventura local reliability area, due to a seven to nine year lead time for conventional gas-fired resources.

26. Gas-fired resources at the current OTC sites are certain to meet the ISO's criteria for meeting LCR needs. Other resources can also meet or reduce LCR needs, but may not be effective in doing so.

27. There is a significant need for LCR resources to replace retiring OTC plants in the LA basin local area by 2021 under every ISO scenario, as well as under the Environmentally Constrained scenario sensitivity analysis.

28. Even if some uncommitted energy efficiency and/or uncommitted CHP resources included in the ISO Environmentally Constrained scenario sensitivity analysis do not ultimately appear, there is a reasonable likelihood that some demand response and/or energy storage resources and/or other distributed generation resources will be viable and able to similarly meet or reduce LCR needs.

29. The ISO's Environmentally Constrained scenario sensitivity analysis includes the highest reasonable levels of uncommitted energy efficiency and uncommitted CHP. This forecast shows an LCR need of 1042 MW for the LA basin local area for effective sites, which is 828 MW below the LCR need in the Environmentally Constrained scenario (everything else being equal).

30. It is necessary that a significant amount of this procurement level be met through conventional gas-fired resources in order to ensure LCR needs will be met.

31. In order to determine a minimum LCR procurement level for the LA basin local area with 100% of the CEC's forecast of uncommitted energy efficiency and uncommitted CHP, and 200 MW of demand response resources, it is reasonable to subtract the effects of these resources from the ISO's Trajectory scenario. Thus (with rounding), the ISO's projected need of 2400 MW in the Trajectory scenario would be reduced by 800 MW to account for 100% of

uncommitted energy efficiency and CHP, and by 200 MW to account for a conservative estimate of demand response resources. This leads to a minimum procurement level of 1400 MW.

32. A maximum LCR procurement level will protect ratepayers from excessive costs resulting from potential over-procurement.

33. In order to determine a maximum LCR procurement level for the LA basin local area it is reasonable to include an additional 400 MW authorization to reflect potential reduced effectiveness.

34. If SCE procures more than the minimum MW amount for the LA basin local area, it will be consistent with the Loading Order to require some additional capacity to come from non-fossil-fueled sources.

35. The ISO did not include any values for uncommitted energy efficiency and uncommitted CHP for the Big Creek/Ventura local area.

36. The ISO did not include any values for demand response or energy storage resources in the Big Creek/Ventura local area.

37. The ISO evaluated and found feasible a transmission alternative for the Moorpark sub-area of the Big Creek/Ventura local area.

38. The ISO has shown that there is a need for in-area generation with operational characteristics similar to retiring OTC plants in the Moorpark sub-area of the Big Creek/Ventura local area.

39. The most likely locations for to meet LCR needs in the Moorpark sub-area are the sites of the current OTC plants. The record shows that it may take seven years or more until operations commence in these locations.

40. The most likely size for at least one replacement plant in the Moorpark sub-area of the Big Creek/Ventura local area is 215 MW, as this is the size of two existing OTC units in that area.

41. There may be a need to procure up to 290 MW in the Moorpark sub-area, after accounting for the likelihood of preferred resources and/or transmission upgrades which are likely to exist in that area and be able to reduce or meet LCR needs.

42. 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.

43. SCE will need to undertake technical studies to integrate certain preferred resources (including energy storage resources) so that they meet local reliability needs, and to work with the ISO to assess the impacts of such resources to meet or reduce LCR needs.

44. A requirement to procure a modest level of energy storage resources, such as 50 MW provides an opportunity to assess the cost and performance of energy storage resources.

45. A requirement to procure at least a minimum level of energy storage resources may provide energy storage providers with market power, to the detriment of ratepayers.

46. OTC plants that comply with SWRCB Track 2 policy (90+% reduction in water usage) without retiring are potential resources to meet SCE's local procurement needs. Such plants may provide SCE with additional capacity options and potentially lower costs to ratepayers.

47. It may take one year or more after today's decision before SCE can submit an application to the Commission with final LCR procurement contracts for Commission approval, after procurement solicitations, bilateral negotiations and studies for preferred resources.

48. Purchased power agreements arising from this decision may create significant debt equivalents on SCE's balance sheet that may need to be mitigated

to preserve SCE's creditworthiness. Such additional debt equivalence will not come into effect until the start of commercial operations of the plant, unless the contract is considered by a rating agency as a continuation of a current contract.

49. The cost allocation mechanism in effect today was established in D.06-07-029 and refined in D.07-09-04, D.08-09-012 and D.11-05-005.

50. AReM's driving peak/decreasing load CAM proposal is inconsistent with the principle that each customer must pay their fair share for the benefits that flow to them from the new generation.

51. AReM's two-step/six criteria framework for CAM allocation imposes additional requirements designed to limit CAM allocation, but does not improve on the fairness of the current allocation.

52. AReM's proposal to levelize the annual revenue requirement would result in bundled customers overpaying for the depreciated value of the generating asset capacity, while non-IOU customers would have paid less than their fair share of the full value of the asset's capacity value.

53. The record does not provide an adequate and persuasive basis upon which to comprehensively consider and adopt any potential changes to the auction mechanism.

54. In AReM's CAM opt-out proposal, it is unclear how AReM's five-year contract term/project life requirement would adequately ensure investment in new resources.

55. It is not clear that a CAM opt-out could be implemented without undue administrative burden.

Conclusions of Law

1. A significant difference between the ISO's reliability mission under § 345 and the Commission's reliability emphasis under § 380(c) is that the Commission

must balance its reliability mandate with other statutory and policy considerations. Primarily, these considerations are reasonableness of rates under § 451 and § 454 and a commitment to a clean environment under Pub. Util. Code sections including § 399.11 (Renewables Portfolio Standard) and § 454.5(b)(9)(C) (Loading Order).

2. Consistent with § 454.5(b)(9)(C), which 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," and the Commission's Loading Order established in the Energy Action Plan, utility LCR procurement must take into account the availability of preferred resources before procuring non-preferred resources.

3. The record in this proceeding supports outcomes which enable the Commission to meet statutory requirements and policy goals with regard to reliability, ratepayer costs and environmental protection, as well as to require the procurement of sufficient levels of diverse resources in a timely manner.

4. SCE's procurement process should have no provisions specifically or implicitly excluding any resource from the bidding process due to technology, except for specific requirements in this decision for the LA basin local area. Except as otherwise required by this decision, SCE's procurement process must have provisions designed to be consistent with the Loading Order approved by the Commission in the Energy Action Plan and § 454.5(b)(9)(C).

5. The ISO models overstate the LCR need for the LA basin local area and the Big Creek/Ventura local area.

6. It is reasonable to assume that 100% of the CEC's forecast of uncommitted energy efficiency and CHP levels will exist in order to determine minimum and maximum LCR procurement level for the LA basin local area.

7. It is reasonable, as a conservative approach, to assume a nominal level of 200 MW of locally-dispatchable demand response resource will be available in the LA Basin to reduce LCR needs by 2020.

8. Adoption of an LCR need range which takes into account the potential differences in the effectiveness of different resources, 100% of uncommitted energy efficiency and uncommitted distributed generation resources, and allows for the potential of demand response resources and energy storage resources which may meet ISO technical criteria for meeting LCR needs, is consistent with the applicable statutory and regulatory requirements for procurement of preferred resources, including the Loading Order.

9. SCE should be required to procure a minimum of 1400 MW and a maximum of 1800 MW in the West LA sub-area of the LA basin local reliability area. No more than 1200 MW should be from conventional gas-fired sources. At least 150 MW should be from preferred resources. Up to 600 MW of capacity may be from preferred resources or energy storage resources (in addition to resources already authorized or required to be obtained via Commission decisions in energy efficiency, demand response, RPS, energy storage and other relevant dockets), subject to the maximum procurement level.

10. SCE should be required to procure at least 50 MW of energy storage resources in the LA basin local area to meet LCR needs, subject to a showing that the costs of some or all of such procurement would not be reasonable.

11. SCE should be required to procure a minimum of 215 MW and a maximum of 290 MW in the Moorpark sub-area of the Big Creek/Ventura local reliability area.

12. SCE should be required to provide a procurement plan to Energy Division for compliance review of the requirements of this decision.

13. SCE should be required to file one or more Applications for approval of contracts to procure LCR resources consistent with this decision.

14. If there is additional information about the viability of preferred resources and/or transmission alternatives in the Moorpark sub-area of the Big Creek/Ventura local reliability area and West LA sub-area of the LA basin local reliability area when SCE files its Application for approval of contracts, that information should be considered at that time.

15. SCE should be required to determine the availability and cost-effectiveness of preferred resources, and energy storage resources, that can offer the necessary characteristics to meet or reduce LCR needs. SCE should then be required to work with the ISO to re-run its transmission modeling load-flow analysis to determine the impacts of such resources. To the extent such resources meet or reduce LCR needs, SCE should reduce procurement of non-preferred resources.

16. Cost-of-service contracts (also called bilateral contracts) allowed under § 454.6 are an option that SCE should be able to use in situations where there is significant market power that would be detrimental to ratepayers.

17. It is reasonable to authorize SCE to use either or both RFOs and cost-of-service contracts in its LCR procurement solicitation process.

18. It is reasonable for SCE to consider retrofits to existing OTC plants, assumed retired in the ISO studies, in its procurement process.

19. All contracts stemming from the LCR procurement authorization we establish today should be brought to the Commission for approval by application for each local reliability area, anticipated sometime in 2014. It is reasonable to allow an earlier application for gas-fired procurement due to the long lead time for such resources.

20. If any extensions to the OTC closure deadlines occur, this can be taken into account in future procurement proceedings or in a review of a procurement application by SCE.

21. The cost allocation mechanism established in D.06-07-029 and refined in D.07-09-04, D.08-09-012 and D.11-05-005 remains reasonable for application in this proceeding without modification, and is fair and equitable as required by Section 365.1(c)(2)(A)-(B).

22. The appropriate procedural venue for SCE to seek any changes it considers appropriate due to debt equivalence related to contracts foreseen from today's decision is its next COC application.

23. The record is insufficient to resolve outstanding questions about a CAM opt-out at this time.

24. It is not within the scope of this proceeding to determine whether SSJID is a large municipalization for the purposes of the CAM.

25. The Motion of MSF should be denied because it seeks to modify a policy adopted by the Commission along with other state agencies, and may conflict with statute.

O R D E R

IT IS ORDERED that:

1. Southern California Edison Company shall procure between 1400 and 1800 Megawatts (MW) of electrical capacity in the West Los Angeles sub-area of the Los Angeles basin local reliability area to meet long-term local capacity requirements by 2021. Procurement must abide by the following guidelines:

a. At least 1000 MW, but no more than 1200 MW, of this capacity must be from conventional gas-fired resources, including combined heat and power resources;

b. At least 50 MW of capacity must be procured from energy storage resources;

c. At least 150 MW of capacity must be procured from preferred resources consistent with the Loading Order of the Energy Action Plan;

d. Subject to the overall cap of 1800 MW, up to 600 MW of capacity, beyond the amounts specified required to be procured pursuant to subparagraphs (a), (b) and (c) above, may be procured through preferred resources consistent with the Loading Order of the Energy Action Plan (in addition to resources already required to be procured or obtain by the Commission through decisions in other relevant proceedings) and/or energy storage resources.

2. Southern California Edison Company shall procure between 215 and 290 Megawatts of electric capacity to meet local capacity requirements in the Moorpark sub-area of the Big Creek/Ventura local reliability area by 2021.

3. Southern California Edison Company (SCE) shall use existing Resource Adequacy (RA) program rules (as developed in Rulemaking 11-10-023 and successor proceedings) to assess the effectiveness of proposed generation solutions for meeting the local capacity requirements need established in this Order. SCE shall identify its assumptions on the effectiveness of any resource for which the RA program does not provide clear guidance.

4. Any Requests for Offers (RFO) issued by Southern California Edison Company pursuant to this Order shall include the following elements, in addition to any RFO requirements not delineated herein but specified by previous Commission procurement decisions (including Decision 07-12-052) and the authorization and requirements of this decision:

a. The resource must meet the identified reliability constraint identified by the California Independent System Operator (ISO);

b. The resource must be demonstrably incremental to the assumptions used in the California ISO studies, to ensure that a given resource is not double counted;

c. The consideration of costs and benefits must be adjusted by their relative effectiveness factor at meeting the California ISO identified constraint;

d. A requirement that resources offer the performance characteristics needed to be eligible to count as local Resource Adequacy capacity;

e. No provisions specifically or implicitly excluding any resource from the bidding process due to resource type (except as authorized in this Order);

f. No provision limiting bids to any specific contract length;

g. Provisions designed to be consistent with the Loading Order approved by the Commission in the Energy Action Plan and to pursue all cost-effective preferred resources in meeting local capacity needs;

h. Provisions designed to minimize costs to ratepayers by procuring the most cost-effective resources consistent with a least cost/best fit analysis;

i. A reasonable method designed to procure local capacity requirement amounts at or within the levels authorized or required in this decision, not counting amounts procured through cost-of-service contracts;

j. An assessment of projected greenhouse gas emissions as part of the cost/benefit analysis;

k. A method to consider flexibility of resources without a requirement that only flexibility of resources be considered; and

l. Use of the most up-to-date effectiveness ratings.

5. Southern California Edison Company (SCE) shall provide a procurement plan for all required and authorized resources in the Los Angeles Basin and Big Creek/Ventura local areas to Energy Division no later than 150 days after the effective date of this decision. SCE shall show that its proposed procurement plan is consistent with Ordering Paragraph 4. SCE shall not go forward with any public procurement process until Energy Division approves the process in writing, except that SCE may proceed with parts of its procurement plan if so authorized. SCE also shall adhere to previous Commission decisions regarding this proposed procurement process, including consultation with the Procurement Review Group and Independent Evaluators.

6. In its proposed procurement plan to be reviewed by Energy Division, Southern California Edison Company shall show that it has a specific plan to undertake integration of energy efficiency, demand response, energy storage and distributed generation resources in order to meet or reduce local capacity requirement needs through 2021.

7. In its proposed procurement plan to be reviewed by Energy Division, Southern California Edison Company shall include all of the following:

- A list of all applicable rules and statutes impacting the plan;
- A detailed description of how it intends to procure resources, specifying the structure of any RFO or alternative procurement process and related timelines;
- A statement as to whether or not SCE intends to seek Commission reconsideration of the solicitation and bilateral contracting determinations in its 2012 RPS procurement plan;
- A detailed list of the RPS procurement authorizations and processes that support SCE's plans to acquire RPS-eligible resources to meet LCR needs;

- A methodology for determining least cost/ best fit that includes evaluating and quantifying performance characteristics that vary among resource type (e.g. time to start, output at various times, variable cost, effectiveness in meeting contingencies, etc.);
- What type of price benchmark will be used in determining cost-effectiveness for resources;
- An explanation for each resource type indicating whether modifications will be made to existing programs or if a new approach will be utilized;
- A methodology for determining peak capacity for resources for which there is not a currently approved methodology for determining Net Qualifying Capacity; and
- A methodology for determining other reliability capabilities (e.g. voltage support) for resources for which there is not a currently approved methodology for determining these capabilities.

8. Southern California Edison Company may provide the conventional gas-fired resources portion of the procurement plan for review ahead of its full procurement plan. If Energy Division approves this portion of the plan Southern California Edison Company may go forward with that procurement.

9. Southern California Edison Company is authorized to procure bilateral cost-of-service contracts to meet authorize local capacity requirements as specified in this Order, including bilateral contracts consistent with the provisions of Public Utilities Code § 454.6.

10. Southern California Edison Company shall work with the California Independent System Operator to determine a priority-ordered listing of the most electrically beneficial locations for preferred resources deployment.

11. Southern California Edison Company (SCE) shall file one Application for approval of any and all contracts entered into as a result of the procurement process authorized by this decision for the Los Angeles basin local reliability area, and one Application for these purposes for the Big Creek/Ventura local reliability area. An exception to the requirement of this paragraph is if SCE's procurement plan, as approved by Energy Division, provides for one separate and earlier Application to procure gas-fired generation for both local reliability areas. SCE shall not receive recovery in rates for the costs related to any such contract before Commission review and approval of these Applications. In addition to currently applicable rules, the Applications shall specify how the totality of the contracts meet the following criteria:

a. Cost-effectiveness;
b. Consistency with the Loading Order, including a demonstration that it has identified each preferred resource and assessed the availability, economics, viability and effectiveness of that supply in meeting the LCR need;
c. Compliance with Ordering Paragraphs 1 and 2;
d. For applicable bilateral contracts, compliance with Public Utilities Code Section 454.6; and
e. A demonstration of technological neutrality, so that no resource was arbitrarily or unfairly prevented from bidding in SCE's solicitation process. To the extent that the availability, viability and effectiveness of resources higher in the Loading Order are comparable to fossil-fueled resources, SCE shall show that it has contracted with these preferred resources first.

12. In its application regarding the Los Angeles Basin local reliability area to implement this decision pursuant to Ordering Paragraph 11, Southern California Edison Company shall present contracts for at least 50 MW of energy storage resources (pursuant to Ordering Paragraph 1) to the Commission for approval,

or have the burden to show that it should procure less than 50 MW because the bids it received were unreasonable.

13. Southern California Edison Company shall treat the retrofitting of a power plant cooling system, which is undertaken to comply with State Water Resources Control Board Statewide Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling and has a compliance deadline before December 31, 2022, as a new resource in considering resources to meet the needs in Ordering Paragraphs 1 and 2.

14. Southern California Edison Company (SCE) shall provide documentation in its Applications required by Ordering Paragraph 11 of efforts to consult with the California Independent System Operator to develop performance characteristics for local reliability, and how SCE meets any such performance characteristics.

15. Southern California Edison Company shall allocate costs incurred as a result of procurement authorized in this decision and approved by the Commission consistent with the cost allocation mechanism approved in Decisions (D.) 06-07-029, D.07-09-044, D.08-09-012 and D.11-05-005.

16. The October 5, 2012 Motion of Megawatt Storage Farms, Inc. is denied.
17. Rulemaking 12-03-014 shall remain open.

This order is effective today.

Dated February 13, 2013, at San Francisco, California.

MICHAEL R. PEEVEY
President
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
MARK J. FERRON
CARLA J. PETERMAN
Commissioners

EXHIBIT C

ALJ/DMG/avs **Date of Issuance 3/14/2014**

Decision 14-03-004 March 13, 2014

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

DECISION AUTHORIZING LONG-TERM PROCUREMENT FOR LOCAL CAPACITY REQUIREMENTS DUE TO PERMANENT RETIREMENT OF THE SAN ONOFRE NUCLEAR GENERATIONS STATIONS

TABLE OF CONTENTS

Title **Page**

TABLE OF CONTENTS
(Con't.)

DECISION AUTHORIZING LONG-TERM PROCUREMENT FOR LOCAL CAPACITY REQUIREMENTS DUE TO PERMANENT RETIREMENT OF THE SAN ONOFRE NUCLEAR GENERATION STATIONS

1. Summary

This is the Track 4 decision in the 2012 long-term procurement proceeding. In this decision, we authorize Southern California Edison Company (SCE) to procure between 500 and 700 Megawatts (MW), and San Diego Gas & Electric Company (SDG&E) to procure between 500 and 800 MW by 2022 to meet local capacity needs stemming from the retired San Onofre Nuclear Generation Stations (SONGS). SCE is required to procure at least 400 MW, and may procure up to the full 700 MW of authorized additional capacity, from preferred resources or energy storage. SDG&E is required to procure at least 200 MW, and may procure up to the full 800 MW of authorized additional capacity, from preferred resources or energy storage.

Consistent with Decision (D.) 13-02-015, the 2013 Track 1 decision in this proceeding authorizing procurement by SCE in the LA Basin, this decision provides "buckets" of procurement for preferred resources (such as renewable power, demand response resources and energy efficiency), energy storage and gas-fired resources. Combining Track 1 and Track 4 procurement authority, SCE is authorized to procure between 1,900 and 2,500 MW in the LA Basin. SCE is required to procure up to 60% of new local capacity in the LA Basin from preferred resources. SDG&E is required to procure at least 25% -- and up to 100% -- of new local capacity from preferred resources. SCE and SDG&E are required to procure at least 50 MW and 25 MW, respectively, from energy storage. The following charts show the procurement levels for each utility. The procurement authorized by this decision as well as the Track 1 and Pio Pico

(D.14-02-016) decisions will offset the retirement of the 2,200 MW SONGS facility and nearly 5,900 MW of once-through cooling plants.

SCE Procurement Authorization
And Requirements
(Track 1 + Track 4)

Resource Type	Track 1 LCR Resources (D.13-02-015)	Additional Track 4 Authorization	Total Authorization
Preferred Resources **Minimum Requirement**	150 MW	400 MW	550 MW
Energy Storage **Minimum Requirement**	50 MW	--	50 MW
Gas-fired Generation **Minimum Requirement**	1000 MW	--	1000 MW
Optional Additional From Preferred Resources/Energy Storage Only	Up to 400MW		Up to 400 MW
Additional from any Resource	200 MW	100 to 300 MW	300 to 500 MW
Total Procurement Authorization	**1400 to 1800 MW**	**500 to 700 MW**	**1900 to 2500 MW**

SDG&E Procurement Authorization
and Requirements

Resource Type	D.13-03-029/ D.14-02-016	Additional Track 4 Authorization	Total Authorization
Preferred Resources (including energy storage) **Minimum Requirement**	---	175 MW	175 MW
Energy Storage **Minimum Requirement**	---	25 MW	25 MW
Additional from any resource	300 (Pio Pico)	300 to 600 MW	600 to 900 MW
Total Procurement Authorization	**300 MW**	**500 to 800 MW**	**800 to 1100 MW**

SCE is authorized to use the procurement process approved in Track 1 of this Rulemaking to procure capacity for the purposes of both Track 1 and Track 4. SCE is expected to file an application for approval of up to 2,500 MW of local capacity resources later in 2014. SDG&E is authorized to solicit procurement offers through an all-source RFO and bilateral negotiations, subject to Energy Division approval of its procurement process. SCE and SDG&E may propose options or contingency contracts in their procurement applications, or separate applications, subject to responses to specific inquiries. SDG&E is strongly encouraged to develop a Living Pilot for preferred resources similar to the one proposed by SCE.

Both SCE and SDG&E are authorized to include the costs of the procurement authorized today through the Cost Allocation Mechanism, consistent with its established rules, and/or other applicable procurement cost allocation processes.

2. Background

2.1. Procedural Background

This proceeding is the successor proceeding to rulemakings dating back to 2001 intended to ensure that California's major investor-owned utilities (IOUs) can maintain electric supply procurement responsibilities on behalf of their customers. The most recent predecessor to this proceeding was Rulemaking (R.) 10-05-006. As stated in the order originating this rulemaking in Ordering Paragraph 3, the record developed in R.10-05-006 is "fully available for consideration in this proceeding" and is therefore incorporated into the record of this proceeding.

In the Scoping Memo for this proceeding, issued on May 17, 2012, the general issues for the 2012 procurement planning cycle were divided into three topics[1]:

1. Identify Commission-jurisdictional needs for new resources to meet local or system resource adequacy (RA), renewable integration, or other requirements and to consider authorization of investor-owned utility (IOU) procurement to meet that need. This includes issues related to long-term renewable planning and need for replacement generation infrastructure to eliminate reliance on power plants using once-through cooling technology (OTC);

[1] Scoping Ruling at 5.

2. Update, and review individual IOU bundled procurement plans consistent with Public Utilities Code Section 454.5;[2] and

3. Develop or refine procurement rules that were not resolved in R.10-06-005, and consider other emerging procurement policy topics.

The Scoping Memo divided the proceeding into three Tracks. Track 1 considered issues related to the overall long-term need for new local reliability resources to meet long-term local capacity requirements (LCRs) through 2022. Such long-term LCRs are expected to result from the retirement of approximately 5,900 Megawatts (MW) from current once-through cooling generators in the Los Angeles (LA) Basin, and approximately 900 MW in the San Diego local area, to comply with State Water Quality Control Board regulations. Other changes in supply and demand over time will also impact long-term LCRs.

The Track 1 decision, Decision (D.) 13-02-015, authorized Southern California Edison Company (SCE) to procure between 1,400 and 1,800 MW of electrical capacity in the West Los Angeles sub-area of the LA Basin local reliability area to meet long-term local capacity requirements (LCRs) by 2021. For the defined portion of the LA Basin local area, at least 1,000 MW, but no more than 1,200 MW, of this capacity was to be procured from conventional gas-fired resources. At least 50 MW was to be procured from energy storage resources. At least 150 MW of capacity was to be procured through preferred resources[3] consistent with the Loading Order in the Energy Action Plans. SCE

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[2] All statutory references are to the Public Utilities Code, unless otherwise noted.

[3] Preferred Resources are defined in the State's Energy Action Plan II, at 2, as follows: "The loading order identifies energy efficiency and demand response as the State's preferred means of meeting growing energy needs. After cost-effective efficiency and

Footnote continued on next page

was also authorized to procure up to an additional 600 MW of capacity from preferred resources and/or energy storage resources. In addition, SCE was required to continue to obtain resources that can be used in these local reliability areas through processes defined in energy efficiency, demand response, renewables portfolio standard, energy storage and other relevant dockets. SCE was also authorized to procure between 215 and 290 MW in the Moorpark sub-area of the Big Creek/Ventura local reliability area.

D.13-02-015, Ordering Paragraph (OP) 11 required that SCE file one Application for approval of any and all contracts entered into as a result of the procurement process authorized by this decision for the Los Angeles basin local reliability area, and one Application for these purposes for the Big Creek/Ventura local reliability area. An exception was made if SCE's procurement plan, as approved by Energy Division, provided for one separate and earlier Application to procure gas-fired generation for both local reliability areas. The Applications were to specify how the totality of the contracts met criteria specified in OP 11. SCE's procurement plan was approved by

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demand response, we rely on renewable sources of power and distributed generation, such as combined heat and power applications. To the extent efficiency, demand response, renewable resources, and distributed generation are unable to satisfy increasing energy and capacity needs, we support clean and efficient fossil-fired generation. Concurrently, the bulk electricity transmission grid and distribution facility infrastructure must be improved to support growing demand centers and the interconnection of new generation, both on the utility and customer side of the meter." Energy Storage is a potential enabling technology, but is not a Preferred Resource because it stores power regardless of how that power is produced. However, in this decision, we also include Energy Storage in the category of Preferred Resources for ease of use unless otherwise noted.

Energy Division in August 2013. SCE currently expects to file applications resulting from Track 1 solicitations later in 2014.

Track 2 of R.12-03-014 considered procurement of system reliability resources for the three major electric IOUs. D.12-12-010 adopted final Standardized Planning Assumptions and Scenarios for Track 2. Modeling results pertaining to flexible resources have not been formally considered by the Commission because the ISO stated at a September Prehearing Conference (PHC) that it was not prepared to submit testimony on the topic. Therefore, a Ruling issued on September 16, 2013 deferred Track 2 to a new 2014 Long-Term Procurement Plans (LTPP) Rulemaking, stating "[b]efore Track 4 was initiated, it was anticipated that Track 2 would be informed by the Track 1 local capacity requirements decision. With the addition of Track 4, it makes sense to also consider local capacity procurement authorized in Track 4 in determining system flexibility needs." The Ruling anticipated system reliability issues related to flexibility would be considered in the 2014 LTPP Rulemaking.

Track 3 of R.12-03-014 considered a number of rule and policy issues related to IOUs' procurement practices. D. 14-02-040 was approved by the Commission on February 27, 2014.

A revised Scoping Memo dated March 21, 2013 in R.12-03-014 initiated Track 4 in this proceeding to consider additional resource needs relate to the long-term outage (and subsequent permanent closure in June 2013) of the San Onofre Nuclear Generation Station, Units 2 and 3 (SONGS). This is the decision for Track 4 of this proceeding.

This decision is a follow-up to the Track 1 decision in this proceeding, but is more narrowly focused on local capacity requirements in what is known as the

SONGS study area. This area consists of all of the territory of San Diego Gas and Electric Company (SDG&E), and the LA Basin portion of SCE's territory.

Generally, we consider new developments related to supply and demand as a matter of course in our bi-yearly LTPP proceedings. The June 2013 permanent retirement of SONGS (following its initial shutdown in 2012) presented a unique and highly significant event. Until 2012, SONGS had supplied 2,246 MW of greenhouse gas (GHG)-free base load power to the LA Basin and San Diego and played an important role in system stability in the San Diego Local Area. The issues of ensuring local reliability and system stability in San Diego and the LA Basin while continuing to meet the State's GHG goals justified expedited reconsideration of capacity needs in the SONGS study area. Track 4 of the 2012 LTPP was opened to grapple with these issues.

At the September 4, 2013 PHC, Administrative Law Judge (ALJ) Gamson noted that the California Independent System Operator (ISO or CAISO) in its August 5, 2013 Track 4 testimony called for deferring Track 4 until after results of the ISO's 2013/2014 Transmission Planning Process (TPP) would be available. The ISO stated that it would be able to provide testimony as to the transmission alternative study results (including reactive power needs) as soon as January 2014.[4] However, the final TPP was not expected to be available until March 2014. Per the ISO's initial recommendation, a decision on Track 4 would not occur until the 2nd or 3rd quarter of 2014.[5]

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[4] A draft 2013/2014 TPP was issued in early February 2014.

[5] The ISO now recommends authorization of procurement amounts at this time, as discussed herein.

The September 16, 2013 Assigned Commissioner/ALJ Ruling noted that the 2013/2014 TPP is expected to provide useful information to inform the Commission regarding a decision on both the level and type of resources to replace SONGS capacity in the long run. The Ruling agreed with the comments of most parties that the determination of the level and type of need to replace SONGS capacity over the long-term should take the TPP into account in making this decision. At the same time, due to long lead times for new resources, the Ruling determined that there it was urgent to start identify and fill any identified need as soon as possible. Therefore, the Ruling established a streamlined schedule to provide guidance and direction to SCE and SDG&E to allow these utilities to move forward on a complex and multi-year procurement process. Under this process, this Track 4 decision will not include the TPP results expected in the first quarter of 2014.

Some parties continue to argue that the Commission should not make a decision on additional procurement related to the SONGS retirement at this time. For example, CEERT states: "The bottom line is, particularly without the benefit of updated assumptions to mirror critical near-term information (i.e., the 2013-2014 TPP results) that can impact mitigation options that could reduce or meet LCR need other than procuring more conventional gas-fired generation, the Commission simply does not now have a reliable record for making any Track 4 GFG procurement authorization for either SCE or SDG&E in January 2014, whether "interim" or not."[6]

[6] CEERT Opening Brief, at 20.

As discussed herein, we determine that it is necessary to authorize additional procurement at this time. The 2013/2014 TPP results are expected to be complete by March 2014. However, further procedural activities in this docket would necessitate at least several months to fully develop a record to incorporate the new TPP results. With long lead-time resources requiring several years of effort, and potential reliability issues surfacing starting in 2018, we cannot wait for further information at this point. Further, additional information inevitably becomes available as time passes. It is simply not possible to both incorporate all information and make timely decisions. However, knowing the TPP results are soon to be available and that additional transmission solutions may impact future LCR needs (by lowering local procurement requirements), we will take a cautious approach to avoid over procurement.

The ISO served its testimony on August 5, 2013. SCE, SDG&E, Office of Ratepayer Advocates (ORA) and the City of Redondo Beach served testimony including modeling studies on August 26, 2013. Comments on questions from the ALJ at the September 4, 2013 PHC were filed on September 30, 2013, with reply comments on October 14, 2013. Opening testimony and testimony in response to modeling parties' testimony was served on September 30, 2013. Rebuttal testimony was served on October 14, 2013.[7] Evidentiary hearings were held October 28 through November 1, 2013. Briefs were filed on November 25, 2013 and Reply Briefs were filed on December 16, 2013. This track of the proceeding was submitted on December 16, 2013.

[7] Certain parties served supplemental and other versions of testimony on other dates with permission of the ALJ.

The parties which served testimony in Track 4 of this proceeding are[8]: AES Southland LLC (AES Southland), Alton Energy Inc. (Alton Energy), California Energy Storage Association (CESA), California Environmental Justice Alliance (CEJA), California Large Energy Consumers Association (CLECA), Calpeak Power, LLC (Calpeak), Center for Energy Efficiency and Renewable Technologies (CEERT), City of Redondo Beach (Redondo Beach), Clean Coalition, Direct Access Customer Coalition/Alliance for Retail Energy Markets (DACC/AReM or AReM/DACC), Eagle Crest Energy Company (Eagle Crest), EnerNOC, Independent Energy Producers Association (IEP), the ISO, Environmental Defense Fund (EDF), Marin Clean Energy (also known as Marin Energy Association or MEA); Natural Resources Defense Council (NRDC), NRG Energy (NRG), ORA,[9] Pacific Gas & Electric (PG&E), Protect Our Communities Foundation (POC), SCE, SDG&E, Sierra Club California (Sierra Club), The Utility Reform Network (TURN), Western Power Trading Forum (WPTF), The Vote Solar Initiative (Vote Solar) and Wellhead Electric Company, Inc. (Wellhead). Testimony from each of these parties was received into evidence at the evidentiary hearing.

2.2. Statutory Requirements, Energy Action Plan and the Loading Order

In considering long-term procurement, the Commission must address a variety of policy and legal concerns. While a primary responsibility of the Commission is to ensure safety and reliability in the electrical system, that

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[8] Parties serving testimony that was subsequently stricken from the record are not included in this list.

[9] Formerly known as Division of Ratepayer Advocates.

responsibility must be balanced with other statutory and policy considerations.[10] Specifically, the Commission has a statutory duty to ensure that customers receive reasonable services at just and reasonable rates,[11] and to protect the environment from deleterious impacts from utility facilities under our jurisdiction.

California law repeatedly emphasizes the importance of maintaining the reliability of the electric grid. For example:

- "Reliable electric service is of utmost importance to the safety, health, and welfare of the state's citizenry and economy." (§ 330(g).)
- "It is important that sufficient supplies of electric generation will be available to maintain the reliable service to the citizens and businesses of the state." (§ 330(h).)
- "Reliable electric service is of paramount importance to the safety, health, and comfort of the people of California." (§ 334.)
- The CAISO "shall ensure efficient use and reliable operation of the transmission grid" (§ 345) and shall "ensure the reliability of electric service and the health and safety of the public." (§ 345.5(b).)
- The Commission "shall ensure that facilities needed to maintain the reliability of the electric supply remain available and operational." (§ 362(a).)

The Commission also has a statutory mandate to implement procurement-related policies to protect the environment. 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

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[10] D.13-02-015 at 35.

[11] Pub. Util. Code § 454.5. All statutory references are to the Public Utilities Code unless otherwise noted.

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, and D.13-02-015 in 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 demand-side resources, followed by renewable resources, and only then in clean conventional electricity supply." (Energy Action Plan 2008 Update at 1.)

In the 2008 Energy Action Plan Update at 20, the Commission further interpreted this directive to mean that the IOUs are obligated to follow the Loading Order on an ongoing basis. Once procurement targets are achieved for preferred resources, the IOUs are not relieved of their duty to follow the Loading Order. 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.[12] 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

[12] D.12-01-033 at 19.

consistency with the Loading Order and advancing California's policy of fossil fuel reduction demand strict compliance with the loading order.

This clarified Loading Order is a departure from the Commission's previous position of procuring energy efficiency and demand response, then renewable energy, and then allowing "additional clean, fossil-fuel, central-station generation," because "preferred resources require both sufficient investment and adequate time to 'get to scale.'"[13] Instead of procuring a fixed amount of preferred resources and then procuring fossil-fuel resources, the IOUs are required to continue to procure the preferred resources "to the extent that they are feasibly available and cost effective."[14] While procuring a fixed amount of preferred resources provides flexibility and a clearer idea of how to approach the procurement process, the Loading Order approach is more consistent with Commission policy.

In D.13-02-015, Ordering Paragraph 4 required that any Requests for Offers (RFO) issued by SCE pursuant to that decision must include 12 elements, including "provisions designed to be consistent with the Loading Order approved by the Commission in the Energy Action Plan and to pursue all cost-effective preferred resources in meeting local capacity needs." Ordering Paragraph 11 (which required SCE to file one or more applications for resource procurement authorized by that decision) required that SCE follow five criteria including: "Consistency with the Loading Order, including a demonstration that it has identified each preferred resource and assessed the availability, economics,

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[13] D.04-06-011, footnote 22, at 31.

[14] D.12-01-033 at 21.

viability and effectiveness of that supply in meeting the LCR need." We maintain our commitment to the Loading Order in this decision.

2.3. Motions to Strike Briefs and Reply Briefs

As discussed in detail in this section, several Motions were filed to strike all or part of Opening or Reply Briefs. SCE filed Motions to Strike the Opening Briefs of Nevada Hydro and MEA, and a Motion to Strike Portions of the Opening Brief of Redondo Beach. SCE and SDG&E jointly filed a Motion to Strike the Opening Brief of POC. PG&E and SDG&E both filed Motions to Strike Portions of the Opening Brief of MEA. In addition, SCE and SDG&E jointly filed a Motion to Strike the Reply Brief of POC.

The revised Scoping Memo stated at page 4:

> "Track 4 will consider the local reliability impacts of a potential long-term outage at the San Onofre Nuclear Power Station (SONGS) generators, which are currently not operational. The CAISO is developing a study to assess both the interim (2018) and long-term (2022) local reliability needs in the Los Angeles Basin local area and San Diego sub-area resulting from an extended SONGS outage."

Generally, all relevant evidence is admissible unless otherwise provided by law. (Cal. Evid. Code, Sec. 350.) Per Rule 7.3 of the Rules of Practice and Procedure, the explanation of the issues to be considered in a particular Commission proceeding is ordinarily provided in a scoping memo. Here, the assigned Commissioner issued an initial scoping memo on May 17, 2012 and a revised scoping memo on May 21, 2013. The revised scoping memo specifically at 4-5 noted that Track 4 would not address general system operational needs and procurement processes.

Rule 13.6(a) provides that although not all technical rules of evidence need be applied in Commission proceedings, "substantial rights of the parties shall be preserved." Rules 13.7 and 13.8 provide details regarding the submission of exhibits and prepared testimony as evidence in Commission proceedings. Rule 13.8(b) provides that substantially modified testimony beyond that provided in prepared testimony shall not be admitted into evidence absent explanation of why the additional testimony could not have been included with the original testimony or other reason why the additional testimony should be admitted. Rule 13.8(d) requires that prepared testimony must be served on parties.

On December 2, 2013, SCE filed a motion to strike portions of Opening Brief of Redondo Beach regarding Track 4 (SCE/Redondo Motion) on the basis that various sections of the Brief relied upon evidence not supported by the record of the proceeding. Such allegedly unsupported analysis included specific details regarding Redondo Beach's power flow analysis. (*See* SCE/Redondo Motion at 2.)

On December 12, 2013, Redondo Beach filed an opposition to the SCE/Redondo Motion (Redondo Response), urging that the motion should be denied because the evidence that is the subject of SCE's motion was submitted as, or attached to the testimony of, Redondo Beach's expert witness Firooz and/or was submitted as part of Redondo Beach's production of analysis in response to SCE data request. (*See* Amended Opening Testimony of Jaleh Firooz on behalf of the City of Redondo Beach, dated October 25, 2013 and Attachment; and *see* Redondo Response at 5.) Redondo Beach further argues that because SCE included argument in its Track 4 Rebuttal Testimony criticizing the substance of Redondo Beach's power flow analysis, it would violate due process of law to both strike Redondo Beach's analysis as well as attempt to bolster its own case by attacking the same testimony.

Here, the evidence that is the subject of the SCE/Redondo Motion is directly related to studies of the local reliability of the SCE and SDG&E local areas by various parties. Such information appears in Redondo Beach's Amended Opening Testimony, allowing SCE the opportunity to attack the validity of such analysis. SCE did in fact attack the validity of Redondo Beach's testimony, and thus was not deprived of the ability to review and criticize such evidence. Thus, the SCE/Redondo Motion is denied in its entirety.

SCE and SDG&E each filed Motions onto strike large portions of the opening brief of MEA on December 4 and December 5, 2013, respectively. SDG&E's filing expressed that it supported SCE's Motion to strike in its entirety (we therefore refer to the two motions as the SCE/MEA Motion). PG&E also filed a Motion supporting SCE's Motion to Strike, and also identifying additional segments of the MEA brief that it urged should be stricken due to lack of factual basis in the record. The Motions claim that specified portions of MEA's brief are not supported by the evidentiary record and that MEA improperly introduces for the first time in Section VIII.C. of its opening brief a new proposal regarding the general application of the CAM to Community Choice Aggregators (CCAs). The SCE/MEA Motion observes that MEA presented no testimony in Track 4 of this proceeding.

MEA filed a response (MEA Response) to all of the IOU's Motions to strike on December 12, 2013, including responses to each IOU's individual criticisms. MEA also included a chart containing its explanations for the admissibility of each portion of its opening brief that SCE requested to be stricken, attached to its Motion as Appendix A.

As reflected in Appendix A of MEA's response to the SCE/MEA Motion, all of MEA's discussion that the utilities requested to be stricken are discussions of the effects of CAM on CCA's in general rather than discussion of the subject of Track 4: local reliability issues raised by the closure of the SONGS facility. For example, MEA argues, "CAM exists as a separate procurement mechanism that must be integrated into the larger whole of the Commission's RA procurement processes in order to ensure fair implementation of all procurement tools." (MEA Response, Appendix A at 18.) MEA itself acknowledges that "the Commission will examine CAM methodology in Track 3 of this proceeding." (MEA Response, Appendix A at 14.) Similarly, regarding MEA's allegedly new proposal regarding how the CAM should be applied to CCA customers, MEA concedes that its opening brief in Track 4 addresses "the greater issue of whether and how the CAM should be applied to CCA customers." (MEA Motion at 2.)

Further, many of the alleged bases for the admissibility of MEA's assertions of fact are legally problematic. California rules of evidence provide that only "[f]acts and propositions of generalized knowledge that are so universally known that they cannot reasonably be the subject of dispute" may be admitted into evidence through judicial notice. (Cal. Evid. Code, Sec. 451, subd. (f); see generally Cal. Evid. Code, Secs. 450 and 451.) The fact that MEA cites to various online news articles and websites to support many of its factual assertions tends to indicate that such matters are not in fact universally known.

The IOU Motions to strike filed against MEA are granted because the stricken language is not relevant to the scope of Track 4. The briefing of issues that are not relevant to the express subject of a particular stage of briefing wastes the time and resources of both parties and Commission staff.

POC filed a Motion for Official Notice of three documents on November 4, 2013. Specifically, those documents were "Reliability Performance Evaluation Working Group – Phase I Probabilistic Based Reliability Criteria

Implementation Procedure," dated June 14, 2001 (Previously marked for the record as POC-4); "Seven Step Process for Performance Category Upgrade Request," Dated October 2004 (Previously marked for the record as POC-5); and "WECC Board of Directors Request Regarding Performance Category Upgrade Request," Dated February 20, 2013 (Previously marked for the record as POC-6). The Joint Utilities filed on November 6, 2013 a Joint Response to the Motion of POC on the basis that the documents did not qualify for Judicial Notice pursuant to Commission Rules of Practice and Procedure, Rule 13.9 and California Evidence Code, Sections 450 et seq.; and further, were not relevant because they predated current NERC standard or were otherwise not applicable to the facts at hand. ALJ Gamson issued an e-mail Ruling on November 14, 2013, denying POC's request for Official Notice of those exhibits. This Ruling is affirmed.

On December 4, 2013, SCE and SDG&E filed a joint motion (Joint Motion) to strike portions of the POC Opening Brief because the specified portions relied upon evidence which the ALJ had deemed inadmissible by the November 14 Ruling. POC filed a response to the Joint Motion arguing that the Joint Motion was overly broad and that some of the materials that were requested to be stricken properly relied upon evidence in the record.

POC's Response belies the content of its Opening Brief. In fact, the sections referenced in the Joint Motion discuss the stricken exhibits POC-4, POC-5, as well as an unnamed source (POC Opening Brief, at 16, fn. 27 provides the source of a quote as "xxxxx at 8."). The Joint Motion is thus granted, and the referenced portions of the POC Opening Brief are stricken.

SCE filed a Motion to Strike Portions of the Opening Brief of Nevada Hydro (SCE/NHC Motion) on December 4, 2013, on the basis that specified segments of the brief attempted to support Commission approval of two proposed grid additions (known as LEAPS and TE/VS Interconnect) that NHC urged would help fulfill resource needs created by the shutdown of SONGS. SCE argued that parties "have not been provided the opportunity to examine LEAPS or the TE/VS Interconnect projects through discovery, testimony or evidentiary hearings." (NHC Motion at 2.)

NHC filed its Motion Opposing the SCE/NHC Motion (NHC Opposition) on December 10, 2013, in which it argued that the specified discussion of the LEAPS and TE/VS projects should not be stricken because the Commission should allow projects proposed by non-IOU entities to be considered to fulfill local reliability needs rather than letting SCE build replacement generation facilities in order to remedy a reliability problem that SCE itself caused. (NHC Opposition at 3-4.)

NHC concedes that, "the Commission did not intend this proceeding to be used to advocate for the merits of any particular solution to the loss of the San Onofre Nuclear Generating Station (SONGS) to SCE's ratebase and to the local generating capacity of the basin[]" and that "this proceeding was not the venue to debate facts supporting the worth of Nevada Hydro's LEAPS and the closely related TE/VS Interconnect." Rather, Nevada Hydro noted that it will make factual assertions in connection with the value of these projects to ratepayers in Certificate of Public Convenience and Necessity applications it will make for each project, through which the merits of each project can be fully vetted." (NHC Opposition at 2-3.) Thus, NHC essentially admits that the characteristics of two particular projects are not matters of factual dispute within the scope of Track 4, which was designed to determine the local reliability resource needs required by the shutdown per the revised Scoping Memo at 4, rather than to identify specific projects that should be developed to fulfill such local reliability needs. Therefore, the SCE/NHC Motion is granted; discussion of the capabilities of the designated sections of NHC's Opening Brief are stricken because they are not relevant to the evaluation of reliability needs.

3. Long-Term Local Capacity Requirements in the SONGS Study Area

3.1. Joint Comparison Exhibit

Per the instructions of the ALJ, parties prepared a Joint Comparison Exhibit, admitted as Exhibit 1. Exhibit 1 shows each party's recommendations for Track 4 needs by utilities, and the basis for the need recommendations. Exhibit 1 is attached as Appendix 1 to this decision.[15]

3.2. Discussion Overview

The early retirement of SONGS removed over 2,200 MW of capacity from southern California. Replacing the capacity from SONGS is not a simple matter. SONGS was located in a critical spot on the coast straddling the SCE and SDG&E territories, providing energy, capacity and ancillary services such as Voltage Ampere Reactive (VAR) support to both territories.

Each year, the RA proceeding (currently R.11-10-023) considers utility capacity needs across California for the upcoming year. In June 2013, D.13-06-024 (among other things) considered capacity needs for 2014. That decision adopted higher capacity requirements for southern California for 2014 than otherwise needed if SONGS was still active. Specifically for the SDG&E local area, D.13-06-024 adopted a local capacity requirement of about 450 MW more than if both SONGS plants were operational.

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[15] The contents of Exhibit 1 were based upon parties Opening Testimony for Track 4, unless otherwise cited from a different source.

Over the medium-term – a period of greater than the one year considered in RA proceedings, but shorter than the 10-year view in LTPP proceedings – both SCE and SDG&E have sufficient supplies to meet projected demands in the SONGS service area through at least 2018, even with the unexpected early retirement of SONGS. Significant supplies have come online in recent years, while overall demand is lower than anticipated several years ago (due to both weakness in the economy and the success of demand side management and energy efficiency programs). In addition, SCE has procured additional capacity to fill the gap left by SONGS over the medium-term. For example, on May 9, 2013 the Commission approved a bilaterally negotiated capacity sale and tolling agreement between SCE and BE CA LLC (BECA) for 3,690 megawatts (MW of contracted capacity in the LA Basin for the period October 2013 to May 2018. (*See* Resolution E-4584.)

Starting in 2015, around 4,900 MW of OTC plants in the local transmission-constrained areas of the LA Basin local area may retire over the next several years, as well as other OTC plants in the San Diego local areas, because of State Water Resources Control Board (SWRCB) regulations.[16] (*See* D.13-02-015 at 6-7 and Section 4.2.2 for a discussion of potential OTC plant closures.) These potential retirements formed much of the basis of the ISO's analysis of 2,400 MW of need in the LA Basin in Track 1.

In this Track 4 proceeding, the ISO modeled retirement of OTC plants in the SONGS study area, along with the retirement of SONGS, to produce an analysis of need for the area. The ISO essentially used the same models as in

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[16] *See* State Water Resources Control Board Resolution No. 2010-0020, adopted on May 4, 2010, effective 9/28/2010; Attachment 1, Milestone No. 26 at 14.

Track 1 to determine LCR needs for 2022 (including the expected retirement of OTC plants), but modified its modeling to reflect the loss of SONGS. Thus, the ISO did not narrowly attempt to identify how much local capacity will be needed to replace SONGS, but modeled overall LCR needs in the SONGS service territory through 2022.

Developing a forecast of needs several years into the future requires incorporation of a number of assumptions. In this proceeding, the ISO based its long-term LCR study on a 1-in-10 year annual peak load and a Category C Contingency.[17] In D.12-12-010 in this proceeding, the Decision Adopting Long-Term Procurement Plans Track 2 Assumptions and Scenarios, the Commission approved the use of a 1-in-10 year peak weather forecast for transmission planning and local area planning.[18] In Track 1 of this proceeding the Commission determined that the ISO's use of a scenario in which two import pathways to SCE's territory would be unavailable on the hottest day in 10 years was an acceptable methodology for determination of LCR needs.[19] Similarly, in D.13-03-029 (the SDG&E Power Purchase Tolling Agreement) the Commission based its LCR determination, in part, on an ISO study that included a power flow model of an outage of the Imperial Valley-Suncrest portion of the Sunrise transmission line followed by the non-simultaneous loss of the ECO-Miguel portion of the Southwest Powerlink transmission line.

On May 21, 2013, the revised Scoping Memo (in its Attachment A) for this proceeding set forth a series of assumptions for the ISO to use in modeling

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[17] A Category C contingency.

[18] D.12-12-010, Attachment A at 23.

[19] D.13-02-015 at 40.

long-term capacity needs in the absence of SONGS. The assumptions are established consistent those in D.12-12-010, D.13-02-015, and D.13-03-029. The revised Scoping Ruling determined that certain revised study assumptions were appropriate, including using a 1-in-10 year versus 1-in-2 year peak weather forecast for transmission and local area planning, and allocation methodologies for assigning energy efficiency and demand response to busbars.

The ISO study is based upon the assumptions in the revised Scoping Memo and forecasts a need of between 4,507 MW and 4,642 MW, respectively depending upon whether the capacity is split 80/20 or 67/33 between SCE and SDG&E.[20] The ISO analysis takes into account the recent Commission authorizations in Track 1 and in D.13-03-029 to calculate an LCR need for the SONGS study area for 2022. Table 1 below (which is also Table 13 in the testimony of ISO witness Sparks) identifies the ISO's calculation of the residual resource needs in 2022 without SONGS:[21] As can be seen in the table, the ISO calculates that between 2,399 MW and 2,534 MW (depending on the allocation between SCE and SDG&E) will be needed in the SONGS study area by 2022. The ISO does not recommend authorization of these levels of procurement at this time.

Certain parties disagree with the ISO's modeling efforts, as discussed in sections below. After detailed review, we agree with the ISO's contention[22] that it correctly modeled the input assumptions described in the revised Scoping Ruling. At the same time, because any complex forecast several years into the

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[20] The ISO also adds a 2.5% reserve margin to its need calculation.

[21] Exhibit ISO-1 (Sparks), at 26.

[22] ISO Opening Brief, at 12-15.

future is by definition imperfect, the ISO's study results cannot be considered an exact need amount.

Table 1

ISO Table 13 – Residual Resource Needs in 2022 Without SONGS

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

The ISO encourages the Commission to move forward with authorizing an interim amount of additional "no-regrets" resource procurement at this time.[23] Specifically, the ISO supports the SCE and SDG&E additional procurement requests.[24] As shown in the Joint Comparison Exhibit, at this time SCE recommends a procurement authorization of 500 MW in the LA Basin and

[23] ISO Opening Brief, at 3.

[24] ISO Opening Brief, at 29-33.

SDG&E recommends a procurement authorization of 500-550 MW in the SDG&E service territory.

The first task at hand in Track 4 is to determine a reasonable and prudent LCR need amount for the SONGS service area by 2022. Several parties argue that the ISO's modeling and reliability assumptions (as well as SCE and SDG&E's assumptions) were at minimum "very conservative."[25] To the extent that the revised Scoping Memo took a conservative approach in its models, so did the ISO.

As the ISO states: "The SCE and SDG&E study results are consistent with the ISO's findings."[26] All of these studies show projected residual long-term local capacity needs ranging from 2,302 – 2,534 MW based on slightly different assumptions and methodologies; certain of these differences we discuss herein. The ISO assumed a significant level of new preferred resources, consistent with the revised Scoping Memo. SDG&E's base case analysis assumes the existence of an incremental 408 MW of not-yet-procured preferred resources.[27] Similarly, the planning assumptions adopted for this track of the proceeding that SCE uses for its studies also assume substantial incremental MW of not yet procured preferred resources for SCE.[28]

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[25] Exhibit ORA-1 (Ciupagea), at 8-9; see also, Exhibit CEJA-1 (May), at 2, 4-6, 9, 14, 21, 28; Exhibit CC-1, (Wang/White), at 1; Exhibit EDF-1 (Fine/Moss), at 2; Exhibit EnerNOC-1, (Tierney-Lloyd), at II-5; Exhibit SC-1 (Powers), at 1; Exhibit NRDC-1 (Martinez), at 4-5.

[26] ISO Opening Brief, at 29.

[27] SDG&E Opening Brief, at 12.

[28] SCE Opening Brief, at 21-22.

We will use the ISO models in this decision as the basis for determining authorized procurement. In this decision, we evaluate potential modifications to the ISO's study results. The ISO agrees that its study results do not include a number of supply and demand considerations that would reduce the total LCR need. Other parties point to other considerations for the Commission to consider in authorizing procurement levels at this time. In nearly all cases, parties (PG&E being the exception) recommend that the Commission authorize procurement levels far below the approximately 2,400 – 2,500 MW output from the ISO study, with a number of parties recommending no additional procurement at this time. We discuss various recommended modifications to the ISO study results in detail below in order to determine analytically if the recommendations of parties are reasonable.

3.3. Potential Forecast Adjustments

In the sections below, we consider a variety of factors which impact the needs shown in the ISO study. It is important to note that all potential changes considered in the record are in one direction – a lower level of LCR need. The main question is whether any potential reductions are certain (or at least very likely), reasonably possible or merely speculative. A prudent authorization should take into account reductions to the ISO forecasts which are certain or very likely, should not take into account reductions which are merely speculative, and should consider reductions which are reasonably possible as providing the basis for the range of prudency.

3.3.1. Track 1 SCE Procurement Authorization

In D.13-02-015, the Track 1 decision of this proceeding, SCE was authorized to procure between 1,400 and 1,800 MW in the West LA sub-area of the LA Basin. Other than PG&E, no party challenges an assumption that the full

1,800 MW of this authorization will ultimately be procured by SCE. Since the full procurement authorization would necessarily be undertaken in the West LA sub-area – which is within the SONGS study area -- this figure directly reduces the ISO forecasted need by 1,800 MW. The ISO agrees and includes this adjustment in its forecast.

SCE's procurement plan was approved by Energy Division in August 2013, and SCE has conducted an RFO for this purpose. As directed by D.13-02-015, SCE will file an application with the Commission for approval of procurement contracts. This application is currently expected later in 2014. SCE may or may not seek approval for the full 1,800 MW (or even 1,400 MW) in its application, depending on the viability of the bids it receives. In addition, the application may or may not be approved in whole or in part. SCE witness Cushnie testified that it is SCE's preference to acquire the full 1800 MW of new LCR resources authorized in D.13-02-015, including the 400 MW of additional Preferred Resources. Cushnie also testified that if SCE does not receive cost competitive and/or cost-effective bids for the full 1,800 MW in its first solicitation, it may seek the needed resources through later solicitations or expansion of existing utility Preferred Resource programs.[29]

The authorization we approved in D.13-02-015 was based on SONGS continuing in service; the Track 1 decision can now be seen as a first step in a two or more step authorization process. We determine in this decision that it would be prudent to authorize further procurement due to the retirement of SONGS – adding up to more than 1,800 MW in total. SCE has stated that it plans over time

[29] RT 2000 – 2001.

to fill the full 1,800 MW from Track 1; no party disagrees that this will occur. Therefore, we find that it is very likely or near certain that 1,800 MW from the Track 1 decision will be procured by SCE and agree with this ISO adjustment in its forecasted LCR need for the SONGS study area.

3.3.2. SDG&E Procurement Authorization

D.13-03-029 determined a local capacity requirement need and directed SDG&E to procure up to 298 megawatts of local generation capacity beginning in 2018.[30] The decision also granted SDG&E authority to enter into a purchase power tolling agreement with Escondido Energy Center. This decision denies authority to enter into purchase power tolling agreements with Pio Pico Energy Center and Quail Brush Power, without prejudice to a renewed application for their approval, if amended to match the timing of the identified need, or upon a different showing of need.

In A.13-06-015, SDG&E sought authority to enter into an amended power purchase tolling agreement with the Pio Pico Energy Center, based upon the authority granted in D.13-03-029. D.14-02-016 in this docket approving the agreement was approved on February 5, 2014. The ISO had already included this adjustment in its study in this record.

We determine in this decision that it would be prudent to authorize further procurement due to the retirement of SONGS. SDG&E has already received approval for procurement based on the authority in D.13-03-029. Therefore, it is clear that SDG&E will procure the amounts authorized in

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[30] Other aspects of that decision push the level to 308 MW. In this decision, we round the D.13-03-029 authorization to 300 MW.

D.14-02-016. We therefore agree with this ISO adjustment in its study for the SONGS study area.

3.3.3. Reactive Power and VAR Support

On June 28, 2013, ORA, CEJA and Sierra Club filed a motion requesting that the Commission ask the ISO to include the full range of reactive power resources identified in ISO's 2012-2013 Transmission Plan in the ISO's local capacity studies without SONGS. These parties argue that power flow modeling results that exclude the full available range of reactive power options make it difficult to identify the true impact that reactive power can have in reducing new procurement need. In response, TURN agreed that the impact of "reactive power alternatives should be considered by this Commission in assessing how to respond to the SONGS retirement." The ISO opposed the motion to include modeling of additional reactive power resources in its Track 4 modeling.

Reactive power must be present in the transmission and distribution system to keep electrical current and voltage in phase and to operate electrical equipment with inductive load, such as motors, magnetic equipment, and transformers. Reactive power capacity is measured in units of volt-ampere reactive (VAR). SONGS was in a strategic location to provide voltage support in southern California. ISO witness Millar testified that SONGS was "critical in supporting voltages and transfers into San Diego."[31]

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[31] RT 1678.

The ISO modeled 720 MVAR of dynamic reactive support in its Track 4 studies, while SCE/SDG&E (jointly) modeled 1,220 MVAR of dynamic reactive support.[32] The ISO model included some, but not all, resources with potential to mitigate the loss of reactive support provided by SONGS in its Track 4 analysis. The Johanna, Santiago, and Viejo shunt capacitors are completed and included in the ISO's modeling.[33] The Huntington Beach synchronous condensers are also completed.[34] However, while the Huntington Beach condensers are assumed by the ISO to be available in the 2018 SONGS-out assessment, they are not included in the revised Scoping Memo's Track 4 2022 assumptions.[35]

ORA points to a number of potential resources which may provide additional VAR support but were not modeled by the ISO,[36] including some data from the ISO's 2012/13 TPP.[37] ORA proposes a 350 MW reduction in need to approximate the impact of additional reactive power resources expected to

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32 Exhibit ISO-1 (Sparks), at 15.

33 Exhibit CEJA-2 (May Supporting Documents) at 48-50 (California Independent System Operator, Response of the California Independent System Operator Corporation to the First Set of Data Requests Related to Track 4 of the Division of Ratepayer Advocates; California Environmental Justice Alliance; Sierra Club, CA; and Clean Coalition, Request No. 2 (July 12, 2013)).

34 Exhibit CEJA-1 (May) at 8.

35 Exhibit ISO-1 (Sparks) at 9; Exhibit CEJA-2 (May Supporting Documents) at 48-50 (California Independent System Operator, Response of the California Independent System Operator Corporation to the First Set of Data Requests Related to Track 4 of the Division of Ratepayer Advocates; California Environmental Justice Alliance; Sierra Club, CA; and Clean Coalition, Request No. 1 (July 12, 2013)).

36 Exhibit ISO-1 (Sparks), at 15.

37 2012/13 TPP, p. 185-186, Table 3.5-10, note identifier "#" (at 186) (Appended as Attachment C to June 28, 2013 Motion).

decrease the need for real power, but ORA recommends that this estimate be confirmed by comprehensive power flow studies in the ISO's 2013-2014 TPP. CEJA shows that SDG&E has proposed two 230 kilovolt (kV) synchronous condenser projects that provide 480 MVARs of dynamic reactive support within the SONGS study area.[38] CEJA contends that a rough estimate of the total need reduction in the San Diego area resulting from these projects is at least 200 MW.[39] SCE has proposed adding another 550 MVAR [Static VAR Compensators] at San Onofre. CEJA shows that the ISO estimates that this addition will reduce need in the LA Basin by 300 MW.[40] This reactive support was not included in the 2022 results of the ISO's Track 4 Opening Testimony.

The June 28, 2013 Motion was not ruled upon during the proceeding. We will now deny this Motion as moot. The revised Scoping Memo did not include any specific amount of reactive power as an assumption for the ISO to model. The record in the proceeding shows that there are sufficient resources to provide VAR support in the SONGS study area without further action at this time.[41] We do not have sufficient information available from the record at this time to determine if additional reactive power resources not modeled by the ISO could be available to reduce LCR needs. Therefore, we find that any estimate of whether or how much additional reactive power support would change LCR

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[38] Exhibit SCE-1, at 28, Table III-3. These projects included a Suncrest 240 MVAR synchronous condenser and a Cannon/Encina 240 MVAR synchronous condenser. (*See* also at 31, Table III-4 notes.)

[39] Exhibit CEJA-1, (May) at 9.

[40] Exhibit CEJA-1 (May Opening Testimony) at 7.

[41] Exhibit ISO-1 (Sparks); at 16-17. Also *see* RT 2046-2050.

needs to be speculative, and will not make any adjustment to the ISO's study for this purpose.

3.3.4. Demand Forecast

The demand input assumptions in the revised Scoping Memo are based on forecasts in the CEC 2012 Integrated Energy Policy Report (IEPR), August 2012 revision.[42] The 2012 IEPR is based on the May 2012 CPUC Energy Efficiency Potential Study and the CEC's California Energy Demand 2012-2022 Final Forecast.[43] The ISO, SCE, and SDG&E studies are all based on demand input assumptions from that same data set.[44]

NRDC argues that the data in these studies provides an incomplete basis upon which to estimate energy savings through 2022 because the data lacks important information such as the effects of the CEC's building efficiency standards set to take effect in 2017 and 2020 and other energy efficiency codes and standards that will produce savings from 2015 and beyond.[45] CEJA also contends that data in the August 2012 IEPR therefore provide an incomplete basis upon which to estimate energy savings through 2022.[46] Sierra Club contends the September 2013 draft update to the CEC demand forecast projects

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[42] Revised Scoping Memo, Attachment A, at 3.

[43] Exhibit NRDC-1 (Martinez); at 7, Diagram 1.

[44] Exhibit ISO-1 (Sparks), at 4; Exhibit SCE-1 (SCE), at 31; Exhibit SDG&E-1 (Anderson), at 6.

[45] Exhibit NRDC-1 (Martinez), at 6-7.

[46] CEJA Opening Brief, at 19-20.

321 MW less load growth than the 2012 demand forecast that serves as the basis for the Commission-approved load assumptions.[47]

NRDC contends the energy efficiency estimates that the ISO and SCE relied on: (i) were based on an incomplete assessment of energy efficiency potential; (ii) omitted incremental "naturally-occurring" savings that are by definition reasonably expected to occur; and (iii) incorrectly used a low estimate of efficiency in SDG&E's local area instead of the mid estimate.[48] NRDC claims that including these additional energy efficiency savings increases the energy efficiency assumptions used in the ISO's and SCE's modeling by 885 MW in the SONGS study area, with 543 MW in the LA Basin and 342 MW in the San Diego local area.[49]

We will not at this time consider changes or updates related to the CEC's demand forecast. It is not reasonable, at this point in this proceeding, to delay the Track 4 decision until all of the assumptions prescribed in the revised Scoping Memo can be restudied; nor is it reasonable to selectively update assumptions. Both the NRDC proposal and the Sierra Club calculation are based on a CEC staff draft forecast of uncommitted energy efficiency that came out in September 2013. Both the ISO and SCE expressed concern about uncertainty in the updated demand forecast, citing the fact that the revised forecast is not yet

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[47] Sierra Club Opening Brief, at 5. This number is derived from Sierra Club Opening Comments, at 7 & n. 14 (citing California Energy Commission, Mid Case LSE and Balancing Authority – Baseline, Form 1.5d, lines 40 and 49. (Sept. 20, 2013) Retrieved from http://www.energy.ca.gov/2013_energypolicy/documents/2013-10-01_workshop/spreadsheets/).

[48] NRDC's item iii is addressed in Section 3.3.10 (Energy Efficiency) in this decision.

[49] Exhibit NRDC-1 (Martinez), at 4-5 (Table 1).

final.[50] Further, any updates after August 2012 were not modeled by the modeling parties, consistent with the revised Scoping Memo. Thus, even if there are changes to the CEC demand forecast, there is nothing in the record to show how or whether any such updates might impact LCR needs.

However, all of the potential demand adjustments in the record point in one direction: lower demand. We find based on the record that updates to the demand forecast are reasonably likely to lower LCR needs. Without quantifying the LCR effect of such potential demand response resources, we conclude that it is reasonable to consider this potential as a directional indicator. In other words, these factors give us more confidence that it is not necessary at this time to authorize the utilities to procure all of the resources indicated to be necessary in the ISO's study.

3.3.5. SPS and Load Shedding[51]

Consistent with guidelines from the Western Electricity Coordinating Council (WECC) and the North American Reliability Corporation (NERC), the ISO has approved Special Protection Systems (SPS), also known as a Special Protection Schemes, on several occasions in California.[52] An SPS allows the use of load shedding as an interim measure when there are insufficient resources to meet more stringent guidelines. The ISO (again consistent with WECC and

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50 Exhibit SCE-2 (Various Witnesses) at 7; RT 1495.

51 "Load shedding" in the context of this proceeding means controlled, but immediate, blackouts of one or more 500 MW blocks (affecting approximately 375,000 households) in a defined area, in response to specific critical failures of generation and/or transmission resources.

52 NERC reliability standard TPL-003 permits load shedding in response to Category C contingencies (ISO Opening Brief, at 17).

NERC guidelines) considers the appropriate reliability level to be an "overlapping" or sequential outage in which one element or "contingency" is lost, there is time for the system to be readjusted (within 30 minutes), and then a second contingency is lost.[53] The two major contingencies usually will be a failure of the largest transmission lines and/or generation resources in the local area. This is known as an N-1-1 contingency. The ISO considers an SPS to be a temporary measure to be in place while long lead-time resources, such as new transmission lines, are being constructed.[54] For example, there is an SPS, with the potential to shed over 100 MW of load, in place for the San Francisco peninsula while PG&E completes several related transmission rebuilding projects.[55] When the new resources are in place, the SPS is ended.[56]

The ISO, SCE and SDG&E calculate the local capacity need for the SONGS study area using different approaches to acceptable mitigation strategies for the limiting N-1-1 contingency consisting of the sequential loss of the ECO-Miguel section of the Southwest Powerlink 500 kV line and the Ocotillo Express-Suncrest section of the Sunrise Powerlink. The ISO did not model the effect of the potential use of an SPS and instead assumes that new resources are needed to resolve the contingency.[57] SDG&E acknowledges the presence of a

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[53] Exhibit ISO-2 (Sparks) at 10.

[54] For large urban areas, the ISO's historic practice has been, as a last resort, to rely on load shedding as an interim measure only until the permanent solution can be put in place (ISO Opening Brief, at 18).

[55] RT 1472.

[56] Two such examples are provided in Exhibit ISO-2 (Sparks), at 5.

[57] Exhibit ORA-3 (Fagan), Attachment B (ISO Data Request Response 2).

WECC-approved SPS in its territory but does not directly model the effect of the SPS when considering the range of need for the N-1-1 contingency.[58] SDG&E and the ISO assume new generation resources (and/or transmission solutions) are needed to resolve the contingency. SCE models and calculates local capacity need assuming the SPS is available to mitigate the limiting contingency, but then requests additional procurement authority because the ISO does not allow reliance on this SPS for long-term planning.[59]

The use of an SPS to mitigate the N-1-1 contingency makes a significant difference in the determination of need. SCE's model shows that reliance on the existing SPS for relevant N-1-1 conditions[60] would decrease SCE's need for new generation by 438 MW in the all generation scenario.[61] Further, the effectiveness of SCE's proposed Mesa Loop-In project reduces the need for new generation from 1,200 MW to 734 MW without load shedding.[62] SDG&E witness Jontry testified that "Planning analyses performed by the CAISO supporting the Final 2013 LCR Technical Study indicate that adherence to the N-1-1 criteria without the possibility of load shedding increases the LCR requirements for the San Diego LCR area by over 1,000 MW, the equivalent of two combined cycle

[58] Exhibit SDG&E-3 (Jontry), at 7.

[59] Exhibit SCE-1 (Chinn) at 6-7.

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

[61] Exhibit SCE-1 (Chinn), at 32, Table III-5.

[62] Exhibit SCE-1 (Chinn), at 37.

units."[63] Jontry also testified that reliance on the SPS in the SDG&E territory would decrease the need for new generation by approximately 150 MW to 250 MW.[64] Considering all possibilities in the record, the amount of new generation that reliance on the SPS could displace ranges from about 588 MW (assuming 438 MW for SCE's and 150 MW for SDG&E) to 1,000 MW or more.[65]

ORA, TURN, CEJA, CLECA, Redondo Beach and Sierra Club all question the decision of the ISO, SDG&E and SCE not to consider the use of an SPS to mitigate the SONGS contingency in the absence of more complete information about the costs, benefits risks and affordability of relying on the SPS.[66] ORA witness Fagan testified that that an SPS could serve as a "'bridge' measure, depending on future transmission and/or preferred resource development circumstances. Fagan testified that:

> (if a new 500 kV) transmission connection between SCE and San Diego…was under consideration, there might be a period of time after OTC unit retirement and prior to completion of such a project that the SPS could serve as a bridge to ensure reliability. Or, if preferred resource development is advancing rapidly but has not yet reached a required threshold level by…2020, but would reach such a level a few years later, the SPS could serve as a bridge during that period."[67]

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63 Exhibit SDG&E-3 (Jontry), at 7-8.

64 RT 1714–1715; Exhibit SDG&E-4 (Jontry), at 2-3.

65 Exhibit TURN-1 (Woodruff), Table 4, at 17.

66 Exhibit ORA-3 (Fagan), at 3-10; Exhibit TURN-1 (Woodruff), at 12-27; Exhibit CEJA-1(May), at 34-38; Comments of the CLECA, September 30, 2013, at 10-1; Exhibit SC-1 (Powers), at 1-11.

67 Exhibit ORA-3 (Fagan), at 11.

CLECA posed the question: "Is it a good use of ratepayer money to add yet another roughly 500-1,500 MW in resources that will rarely if ever be used instead of using controlled load shedding by SDG&E in the case of an N-1-1 contingency under a 1-in-10 peak load condition? This is not a matter of failing to meet NERC and WECC requirements. This is a matter of having ratepayers foot the bill for going beyond those requirements."[68] TURN witness Woodruff emphasized that consideration of whether to allow load shedding to mitigate the key N-1-1 contingency should not be confused with a lack of concern about reliability.[69]

Parties dispute whether it would be cost-effective to have an SPS in place in San Diego. ORA witness Fagan testified that the alternative to an SPS would be the cost of new gas-fired generation, estimated to range from $595 million (436 MW) to $1.36 billion (1,000 MW) using $1,363/kW as the installed capital cost for a combustion turbine.[70] Similarly, TURN witness Woodruff estimated that the cost of SCE's Preferred Resource scenario appears to be $595.5 million higher in the absence of using a load shedding SPS as part of a contingency mitigation plan.[71]

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[68] CLECA Comments, at 10-11.

[69] Exhibit TURN-1 (Woodruff), at 26-27.

[70] Exhibit ORA-3 (Fagan) at 7.

[71] Exhibit TURN-1 (Woodruff), Table 4, at 17.

Other parties argue that an SPS is not appropriate and/or is not cost-effective. ISO witness Sparks testified that it is the ISO's position that load shedding in the highly urbanized San Diego area should not be used as a transmission planning tool, due to the significant amount of load that would be subject to load shedding, the sensitivity of urban loads to large blocks of load shedding, the complexity of operating arrangements in the area, and the proximity of particular transmission lines.[72] SDG&E witness Jontry cautioned against the "potentially severe economic and civil consequences"[73] that might result from controlled load shedding. Neither the ISO[74] nor SDG&E[75] conducted studies to compare the cost or risk of relying on its SPS versus the costs of other resources to mitigate the critical contingency.

IEP witness Monson testified that loss of service would result in costs including "spoilage, lost production time, and lost sales" as well as well possible traffic accidents and medical problems.[76] Monson testified that the costs of curtailment of firm load "depend on the frequency and duration of curtailments, the amount of capacity curtailed, and the value of service for customers," but were not calculated.[77] IEP calculates that, using an average financial cost of an

[72] ISO-3, at 7.

[73] Exhibit SDG&E-4 (Jontry), at 2.

[74] RT 1843.

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

[76] Exhibit IEP-2 (Monsen), at 15.

[77] Exhibit IEP-2 (Monsen), at 15-16.

outage of the electric system of $40,000/MWh for a 12-hour outage, like the one San Diego experienced in September 2011, the cost of a similar outage would approach a quarter of a billion dollars.[78] However, TURN performed an analysis (which it terms "preliminary") showing under various assumptions that investments to avoid load shedding in case of an N-1-1 contingency are not cost-effective for ratepayers.[79]

Redondo Beach contends that the Commission could find that the costs and possible consequences of any controlled load drop are unacceptable, but the Commission should make such findings based on concrete analytic evidence. Redondo Beach claims such evidence is not present.[80] We agree that the evidence in this proceeding is not conclusive on this point.

In trying to estimate the potential consequences of an SPS, relevant factors include how often the identified N-1-1 contingency in San Diego is likely to occur, the likelihood that the contingency would occur when there were not adequate resources to serve load in the event one of the lines went down, and a range of costs of not serving load. One factor to consider is that the SPS might never be used.[81] ISO witness Sparks testified that there is a significant risk (and historical record) of fire in the area of the two transmission lines (which are as close as four miles apart) which form the N-1-1 contingencies, and that the

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78 IEP Opening Brief, at 16. IEP adds: "The social costs of blacking out 500 MW of customer load, including the disruptions to transportation, traffic control systems, and waste management systems, would be substantial, if difficult to quantify."

79 TURN Opening Brief, at 13-14.

80 Redondo Beach Opening Brief, at 17.

81 RT 1837.

probability of a simultaneous outage of the two lines "trends" towards one in 21 years.[82] Other credible data in the record shows likely intervals between potential failures may be up to 928 years.[83]

As ORA witness Fagan points out, ISO data shows the highest load on the combined Orange County SCE/SDG&E region occurs for no more than 89 hours over the course of the 3672-hour period between May 1 and September 30th, or less than 2.5% of summer hours.[84] Redondo Beach attempted to estimate the probability that two sets of low probability events – i.e., very high peak load and loss of both 500 kV lines in sequence – would occur at the same time on the same day, contending that "the probability of an N-1-1 contingency occurring at the peak hour of a 1-in-10 load forecast is…about 1 in a billion for the peak hour" or about 1 in 5 million if surrounding hours are included. [85] ISO witness Millar testified that "we don't believe this circumstance is one where a straightforward cost benefit analysis is an effective consideration."[86]

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[82] Exhibit ISO-2, at 5-6.

[83] Exhibit ISO-2 (Sparks), at 5– 6; *See* Exhibit TURN x ISO 7, at 56; cf. Ex. TURN x ISO 2, at 3.

[84] Exhibit ORA-3 (Fagan) at 9.

[85] Redondo Beach Report, p. 13; Redondo Beach Opening Brief, p. 14.

[86] RT 1613; *see* also RT 1622: appropriate use of cost benefit information refers to "circumstances lending themselves to producing a meaningful result that can be effectively taken into account by a decision maker in weighing the costs against the calculation benefits of mitigating against the large outage.

Per § 345, the ISO is responsible for operating the transmission grid used by SCE, PG&E, and SDG&E "consistent with achievement of planning and reserve criteria no less stringent than those established by the Western Electricity Coordinating Council and the North American Reliability [Corporation]." The Commission is responsible for service reliability and maintaining reasonable rates. In previous decisions, we rejected the notion of "reliability at any cost," indicating instead that "measures that are proposed to promote greater grid reliability should be evaluated by weighing their expected costs against the value of their expected contribution to reliability…"[87]

We do not find that long-term reliance on an SPS to resolve LCR need related to the retirement of SONGS is appropriate. We agree with SCE witness Chinn that "load shedding should only be used judiciously as mitigation for contingencies."[88] We also agree with IEP that we should not make a "change to long-term resource planning policy to incorporate blackouts as a standard, planned response to N-1-1 contingencies, a response on par with supply or demand-side additions, to avoid procuring the resources needed to reduce the risk of blackouts."[89]

The crux of the issue before us regarding load shedding is whether we should <u>at this time</u> authorize additional procurement to achieve the level of reliability the ISO recommends: Sufficient resources to mitigate a specific, but unlikely, N-1-1 contingency in the SDG&E territory. We note that an SPS that would allow load shedding is an option permitted by NERC and WECC

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

[88] Exhibit SCE-2 (Chinn) (Revised 10/24/13), at 15.

[89] IEP Opening Brief, at 18.

standards.[90] We find based on the record the following: 1) The ISO has the authority within WECC/NERC guidelines to implement or continue a SPS in the SDG&E territory; 2) Such an SPS in the particular area identified by the ISO has a likelihood of an N-1-1 failure between every 21 and 928 years; 3) Even if such a failure occurs, it will not lead to load shedding except for less than 2.5% of summer hours;[91] 4) There would need to be a minimum of 588 MW fewer resources if there is a temporary SPS in place, as compared to the resources needed to support the N-1-1 contingency identified by the ISO; 5) The cost to ratepayers of these additional resources would be at least $595 million (this amount is the benefit of an SPS approach) and there is evidence that such investment may not be cost-effective; 6) The cost to affected customers of a load shedding event under an SPS approach is estimated at under $250 million per event, and must be weighted by the low probability of the occurrence of load shedding.

We conclude that it is not reasonable at this time to authorize utilities to procure – and ratepayers to pay the cost of -- the additional resources required to fully mitigate the identified N-1-1 contingency without an SPS. This determination does not mean that we favor a lower level of reliability than does the ISO. We agree with SDG&E and IEP that that it is not prudent to take a long-term system planning approach that assumes reliance on load shedding in a

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[90] Exhibit ORA-3 (Fagan), at 7: 15 and Attachment B, at 1.

[91] We recognize that an outage resulting from an N-1-1 contingency may occur outside of summer hours; however, the summer is generally considered the most likely season for this to occur due to higher temperatures, higher load and greater fire risk near the subject transmission lines.

densely-populated urban area as mitigation for contingency events.[92] Instead, we determine that it is prudent to wait to see what resources develop in the SONGS service area to determine whether an SPS or other load-shedding protocol need serve as a bridge until such resources are in place. In particular, we see the likelihood that the procurement of preferred resources as authorized herein (and as acquired through other means) will develop sufficiently over time to mitigate the need for further resources, so that the SPS in the SDG&E territory can be lifted and reliability at an N-1-1 contingency level can be maintained. In addition and/or alternatively, transmission solutions such as the Mesa Loop-In may mitigate the need for further resources.

We note that ISO witness Millar testified that the ISO intends to address its transmission planning policy regarding load shedding in large urban areas as part of an open stakeholder process in the first half of 2014.[93] While it is unknown what the outcome of this process will be, it is possible that the ISO will adopt a different position that it currently holds regarding when an SPS should be approved and how load shedding should be considered. By not authorizing procurement at this time to the ISO's current policy standard, we retain the option of reconsidering the appropriate level of procurement in the future in the light of future ISO planning policy.

Therefore, we conclude that it is reasonable to subtract a conservative estimate of 588 MW from the ISO's forecasted LCR need because our policy decision entails a certainty that resources will not be procured at this time to

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[92] SDG&E Opening Brief, at 30.

[93] Exhibit ISO-7, at10.

fully avoid the remote possibility of load-shedding in San Diego as a result of the identified N-1-1 contingency.

3.3.6. Category C vs. Category D

Several parties argue that the Category C contingency in San Diego modeled by the ISO is functionally a Category D contingency under WECC reliability standards, using a probabilistic analysis. Sierra Club witness Powers,[94] CEJA witness May and POC witness Peffer presented extensive technical testimony on this point; all claim that the SWPL/Sunrise overlapping N-1-1 contingency is a Category D extreme event for which transmission upgrades are not required under NERC standards.[95] ISO witness Sparks responded that these witnesses seemed to be confusing the overlapping outages of the two lines (loss of one element, system re-adjusted, followed by loss of a second element), with the simultaneous loss of two transmission lines (a Category D contingency).[96]

On cross examination, witness Powers claims the overlapping outage of SWPL and Sunrise is a "functional" Category D because SDG&E could "convert it from a Category C to a Category D" using the WECC process followed by SDG&E in evaluating the performance criteria of the Sunrise route alternatives.[97] However, SDG&E witness Jontry testified that the WECC re-classification process is not available for an N-1-1 contingency.[98] ISO witness Sparks also

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[94] Exhibit SC-1 (Powers), at 3; RT at 1931, 1932, 1935.

[95] Exhibit SC-1 (Powers), at 2; Exhibit POC-1 (Peffer), at 11; Exhibit CEJA-1 (May), at 30.

[96] Exhibit ISO-2 (Sparks), at 11-13.

[97] RT 1932. (*See* also Exhibit POC-X-CAISO-3.)

[98] RT 1775.

noted that he had never seen the process applied to a Category C3 contingency, and that WECC is moving to eliminating the process altogether.[99]

In relevant past decisions, the Commission has disputed some of the ISO's input assumptions to its modeling (such as megawatts of demand response and incremental uncommitted energy efficiency, and load forecasts). We modify various ISO input assumptions in this decision as well. Yet, the Commission has consistently relied on ISO transmission planning studies which use the ISO's methodology and interpretation of Category C and D contingencies. This is seen in decisions including the 2013 RA decision (D.13-06-024), the Track 1 LTPP decision in this docket (D.13-02-015), and our recent SDG&E procurement-related decision (D.13-03-029). In these decisions we defer to the ISO regarding power flow modeling. For example, D.13-02-015 Findings of Fact 2 states: "It is reasonable to use local capacity studies and power flow modeling from the ISO for LCR forecasting. . . ." Similarly, in D.13-03-029, Conclusion of Law 5 states: "The CAISO's modeling assumptions, other than with respect to uncommitted energy efficiency and demand response and incremental CHP, are reasonable." Further, the 2013 RA Decision relies on the ISO's 2014 Local Capacity Requirements Study,[100] which employ the same Category C distinctions that the ISO uses here in Track 4.

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[99] RT 1562.

[100] D.13-06-024, Conclusion of Law 1 states: "The ISO's 2014 Local Capacity Technical Analysis Final Report and Study Results should be approved as the basis for establishing local procurement obligations for 2014 applicable to Commission-jurisdictional LSEs, using the "no SONGS" scenario."

We will use the ISO power flow models as the basis for this decision as well. The ISO power flow modelling was performed consistent with the revised Scoping Memo. The exogenous modifications we make (including assumptions regarding load-shedding) do not affect the modelling directly, but inform our judgment regarding appropriate procurement levels. Changing a Category C contingency to a Category D contingency would directly change the ISO model output. We find that 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. In any event, we find no credible basis upon which to find that the ISO's analysis is flawed and that the limiting contingency for the SONGS study area is anything but the N-1-1 Category C3 SWPL/Sunrise overlapping outage assumed and modeled by the ISO.

3.3.7. Transmission Solutions

SCE proposes a potential transmission solution to part of the LCR need in the SONGS study area. The Mesa Loop-In project involves rebuilding and upgrading the existing Mesa 230 kV substation in the LA Basin to 500 KV and looping the Vincent – Mira Loma 500 kV line and two 230 kV lines into the substation. SCE describes several positive benefits of the Mesa Loop-In: 1) it relieves the loading on the Serrano corridor by delivering power into the LA Basin from the northwest;[101] 2) because of the addition of the new 500 kV substation, the capacity of the transmission grid to import power to the LA Basin would be increased,[102] allowing any new resources to come from outside of the

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101 Exhibit SCE-1 (Silsbee), at 36; RT 2160.

102 Exhibit SCE-1, at17; at 36.

LA Basin, where there are fewer impediments to generation development, fostering more competition and reducing procurement costs;[103] 3) the Mesa Loop-In would reduce the amount of gas-fired generation that would need to be sited in the LA Basin by approximately 1,200 MW[104] (734 MW if no load shedding or additional gas-fired generation in the SDG&E territory).

Due to the Mesa Loop-In's characteristics, including the fact that most of the infrastructure changes will take place within the boundaries of the current substations, SCE contends it is reasonably possible the Mesa Loop-In can be constructed by 2020 when significant amounts of OTC generation is expected to retire. We agree with SCE. SCE cautions that this completion schedule will require aggressive scheduling of regulatory agency reviews and minimal public opposition.[105]

The Mesa Loop-In project was submitted to the ISO as part of its 2013-2014 Transmission Planning Process. However, there is no record to determine if the Mesa Loop-In will be approved by the ISO in its TPP. Even if this occurs, it is not possible to know at this time if this project would receive all necessary permits and approvals and be constructed in the timeframe SCE suggests; SCE admits that many significant hurdles would need to be overcome for this to occur. Nevertheless, the Mesa Loop-In proposal is a promising and reasonably likely alternative to other new resources in the LA Basin. While significant uncertainties require that we not adjust the ISO's forecast at this time to assume LCR benefits from the Mesa Loop-In project, it is important to keep in mind that

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103 Exhibit SCE-1, at 36; Exhibit SCE-2, at 4.

104 Exhibit SCE-1, at 36.

105 SCE Opening Brief, at 28.

it may not be necessary to authorize (or if authorized, ultimately approve) funding for various procurement projects if the Mesa Loop-In becomes viable in a timely manner.

AES Southland points out that any reduction of the need for LA Basin generation by the Mesa Loop-In does not reduce overall generation needed to maintain system reliability; rather it just allows the need to be met by resources located over a larger geographic area.[106] For the LA Basin Transmission Scenario, SCE modeled 600 MW of generation outside the LA Basin.[107] Thus, the Mesa Loop-In project may lead to an overall reduced need for 134 to 600 MW, accounting for the 734 to 1,200 MW reduction in LCR in the SONGS service territory, but 600 MW of new generation outside of the SONGS service area. The GHG impacts of the overall impact of the proposed Mesa Loop-In project would be considered in a separate application.

SDG&E examined the addition of two regional transmission projects that could reduce LCR need. The first project SDG&E included is a 500 kV Direct Current (DC) transmission project from Imperial Valley to SONGS.[108] SDG&E's study shows the addition of a DC line would reduce the San Diego generation requirement by 850 MW and would reduce the generation requirement for the LA Basin by 551 MW.[109] The second project is a 500 kV regional transmission project from Devers Substation to a new 230 kV substation in north San Diego

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106 AES Southland Opening Brief, at 7.

107 Exhibit SCE-1 (Silsbee), at 40.

108 Exhibit SDG&E-3 (Jontry), at 8-9.

109 Exhibit SDG&E-3 (Jontry), at 13.

County.[110] SDG&E shows this project would reduce the LCR need for San Diego by 550 MW and reduce the LCR need for the LA Basin by 400 MW.[111] SDG&E witness Jontry noted that both of these projects "may differ slightly [from those submitted to the 2013/2014 Transmission Planning Process], but will be electrically equivalent."[112] SDG&E testified that it submitted two 500 kV options with different routing options from Imperial Valley to North County to the ISO's 2013-2014 Transmission Planning Process.[113] SDG&E witness Anderson testified that "adding major transmission capability in to the load pocket can reduce the need for local generation by approximately 1000 to 1400 MW," but that there was substantial uncertainty as to how quickly those projects could be licensed and built.[114]

There is not enough information available at this time to make a specific finding that any transmission project will be able to reduce the LCR need in the SONGS service territory by 2022. Partially, this is because the ISO's 2013/2014 TPP is not yet final. Beyond this, there are various approval and permit processes – as well as public input – before construction can begin. The construction process can take several years, and is subject to significant delay. We find that there is a reasonable possibility that at least one of the transmission solutions examined by SCE and SDG&E will be operational by 2022. The least

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[110] Exhibit SDG&E-3 (Jontry), at 9.

[111] Exhibit SDG&E-3 (Jontry), at 13.

[112] Exhibit SDG&E-3 (Jontry), at 9.

[113] RT 1749.

[114] Exhibit SDG&E-1 (Anderson), at 2.

complex of these projects is the Mesa-Loop-In project, which is therefore the most likely to meet this timeframe.

We find based on the record the proposed transmission solutions in the record would most likely lower LCR needs, if completed in the appropriate timeframe. While the LCR effect of such potential transmission solutions has been quantified, we conclude that it is reasonable to consider this potential as a directional indicator rather than a reduction to the LCR needs identified by the ISO. Therefore, potential transmission solutions give us more confidence that it is not necessary at this time to authorize the utilities to procure all of the resources indicated to be necessary in the ISO's study.

TURN points out that it is conceivable that future transmission planning efforts by the two utilities and the ISO will identify additional transmission projects or other measures that can meet local need more cost effectively.[115] We agree; however, this potential is speculative based on the record in this proceeding.

3.3.8. Demand Response

The revised Scoping Memo sets out assumptions for demand response resources for 2018 and 2022. The demand response assumptions are the same for both years, 189 MW of "fast" demand response (potential to be activated in 30 minutes or less after the first contingency) to be modeled as a "First Contingency" resource and 997 MW of demand response which is to be

[115] TURN Opening Brief, at 5.

accounted for as a "Second Contingency Resource."[116] According to the revised Scoping Memo, the studies "shall model 'First Contingency' resources as addressing the first contingency to prepare for the second contingency." Second Contingency resources "are not modeled but would be accounted for as potential resources to address any residual need identified by a second contingency condition in the studies." The revised Scoping Memo states an expectation that these demand response programs could become more capable of meeting needs by 2022 while also noting that further action would be needed to make that a reality, and that the study results "shall provide a broad assessment of local area needs that inform the programs of 'second contingency' resources such that they can adapt to meet the residual need."[117]

CEJA argues that the ISO's treatment of 'second contingency' demand response is problematic for two reasons: first, the ISO appears to assume that the character of the demand response programs that exist today are the same as will exist in 2022; second, the Commission recently instituted R.13-09-011 to enhance the role of demand response programs. CEJA notes that R.13-09-011 makes it clear that the Commission does not intend for demand response programs to remain in stasis for the next 9 years.[118] Sierra Club makes similar points.[119]

NRDC argues that all of the model results presented by the ISO and the utilities should be adjusted downward in order to account for the amount of

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[116] Per the revised Scoping Memo, price responsive and day-ahead demand response programs or demand response programs outside the geographic areas of most concern (the west LA Basin and the SDG&E territory) fit the "Second Contingency" category.

[117] Revised Scoping Memo, Attachment A, at 2.

[118] CEJA Opening Brief, at 11.

[119] Sierra Club Opening Brief, at 8-1 l.

demand response that is reasonably expected to occur. NRDC contends that the ISO only used the 'first contingency' resources in its studies, which NRDC contends are only a portion of the demand response input assumptions that the revised Scoping Memo directed it to use in its studies. NRDC maintains that "second contingency" resources identified in the revised Scoping Memo should be counted toward meeting LCR needs.

We disagree with these parties. The revised Scoping Memo specifically indicated that: "'Second Contingency' consists of assumptions representing residual resources that could be used to meet subsequent post-contingency needs. 'Second Contingency' resources are not modeled but, would be accounted for as potential resources to address any residual need identified by a second contingency condition in the studies (emphasis added)."[120] Consistent with the instructions of the revised Scoping Memo, the 997 MW of 'second contingency' demand response in the ISO modeling was not available to avoid the second contingency, but would be available to respond to the second contingency.

As ISO witness Sparks stated:

> "…our understanding, is the existing (demand response) that doesn't have characteristics that -- at least currently doesn't have characteristics that meet the needs. Not to say that we couldn't find some other (demand response) or modify that (demand response), but at this point in time we didn't want to cause confusion that that (demand response), as it exists today, could meet the need. And so that was not included in the residual calculation."[121]

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[120] Revised Scoping Memo at 2.

[121] RT 1456.

The ISO's modeling followed the revised Scoping Memo's instructions, which reflected the operating and performance characteristics of 'second contingency' demand response resources. In the ISO's reliability rubric, these resources should not be counted because they cannot be relied upon to activate within 30 minutes after the first contingency. We find that, consistent with the revised Scoping Memo, the ISO properly did not model 'second contingency' demand response resources for determining LCR needs. We will not revisit these demand response assumptions here for the purpose of changes to the ISO study itself, but instead consider whether potential additional demand response should affect authorized procurement amounts.

SCE had already started its analysis prior to the issuance of the revised Scoping Memo. SCE found that, "[o]verall there is about a thousand megawatts of [demand response] assumed in the overall Los Angeles Basin." In the smaller West LA Basin (where the revised Scoping Memo is focused for demand response resources), SCE assumed 620 MW of demand response available as a reasonable estimate and discounted that amount by 50%, because those programs were initially developed to meet system, not local, needs. In addition, SCE augmented this amount by 283 MW of additional demand response in the Johanna/Santiago Substations (also in the west LA Basin), again discounted by 50%. In total, SCE assumed 451 MW of demand response in the Track 4 modeling.[122]

[122] RT 2121 – 2122.

We will not modify the ISO's LCR analysis based on 'second contingency' demand resources. However, the expectation of over hundreds of MWs of 'second contingency' demand response resources identified by the revised Scoping Memo cannot be disregarded. SCE's model assumed that some of this demand response would be available to meet LCR needs. EnerNOC points out that the ISO in some cases does count demand response resources that do not activate in under 30 minutes as counting toward reducing the LCR need.[123] While the ISO contends (consistent with the revised Scoping Memo) such resources would not mitigate the N-1-1 contingency under its rubric, the revised Scoping Memo took a conservative view of the potential of demand response resources in this regard.

There may be a transient design issue with demand response resources at this time. CEJA is correct that we expect demand response programs to evolve and improve. In the future, it is reasonable to expect that some amount of what is now considered 'second contingency' demand response resources can be available to mitigate the first contingency, and therefore meet LCR needs. ISO witness Millar agrees that it is possible that additional demand response resources with more notice would also be able to respond within the time frame expected to meet the N-1-1 contingency within 30 minutes.[124] For example, demand response customers may have provisions which, when they are alerted in advance of a potential need for these resources to activate (such as a very hot weather forecast), require such resources to be activated within 30 minute when called. Further, ISO witness Sparks testified that, in "the current ISO planning

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123 EnerNOC Opening Brief, at 15.

124 RT 1692.

process," the ISO is "also working on identifying the necessary characteristics of preferred resources such as demand response such that it can meet local needs."[125]

We do not at this time assume additional demand response resources, beyond those modeled by the ISO, will be available to meet LCR needs. We do find that there is a reasonable likelihood that more demand response resources will be available for such purposes in the future. While we cannot quantify the LCR effect of such potential demand response resources, we conclude that it is reasonable to consider this potential as a directional indicator. In other words, this gives us more confidence that it is not necessary at this time to authorize the utilities to procure all of the resources indicated to be necessary in the ISO's study.

3.3.9. Energy Storage

On October 17, 2013, the Commission issued D.13-10-040, the "Decision Adopting Storage Procurement Framework and Design Program". That decision, in Appendix A, at 1., states that a "guiding principle" for energy storage is: "The optimization of the grid, including peak reduction, contribution to reliability needs, or deferment of transmission and distribution upgrade investments." D.13-10-040, Appendix A, at 2, sets energy storage targets of 580 MW for SCE and 165 MW for SDG&E. These targets are to be procured gradually through biennial solicitations from 2014 through 2020.[126] Though the utilities may defer up to 80% of their MWs to later procurement periods,[127] they

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[125] RT 1553.

[126] D.13-10-040 at Appendix A, at 5, Section 3(a).

[127] D.13-10-040 at Appendix A, at 3, Section 2(c).

must ultimately have 100% of their respective storage targets online no later than December 31, 2024.[128]

The ISO presumes "the Commission will consider energy storage targets identified in" the energy storage decision, but is concerned about "the ultimate amount, location and timing of energy storage actually developed."[129] SCE similarly suggests that some portion of the targeted storage resources will end up in the LA Basin and be available to meet LCR needs, but as SCE witness Nelson testified, the "timing is unknown. It's not clear to me…what the accounting will be for LCR purposes of storage."[130]

SDG&E contends there are many issues related to energy storage procurement that require resolution, including the operational characteristics that energy storage must satisfy in order to be relied upon to meet LCR need. SDG&E witness Anderson noted that "some amount of energy storage – the right kind of energy storage at the right locations – may play a role in meeting some of SDG&E's identified LCR need."[131] He noted that energy storage procurement undertaken in order to meet to targets adopted in the dedicated energy storage proceeding may or may not be procurement capable of meeting LCR need.[132]

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[128] D.13-10-040 at Appendix A, at 1, Section 2(a) ("Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company shall procure (i.e., pending contract, under contract, or installed) 1,325 MW of energy storage by 2020 with the requirement that the overall procurement goal of 1,325 MWs will be installed and delivering to the grid by no later than the end of 2024….").

[129] ISO Comments, at 3.

[130] RT 1903.

[131] Exhibit SDG&E-2 (Anderson), at 1.

[132] Exhibit SDG&E-2 (Anderson), at 2.

CEJA contends that with storage procurement anticipated by D.13-10-040 complete by 2020 and energy storage deploying relatively quickly,[133] most if not all of the decision's storage targets should be available by 2022. Therefore, CEJA recommends that the Commission include SCE's and SDG&E's energy storage targets to lower LCR needs within the SONGS study area by 612 MW.
Sierra Club similarly would reduce Track 4 procurement by 745 MW to account for energy storage in SDG&E's and SCE's territories by 2020.[134]

In D.13-02-015, we required procurement of 50 MW of energy storage as part of SCE's 1,400-1,800 MW procurement requirement. This procurement level is already included in the ISO, SCE and SDG&E calculations of LCR needs. In D.13-02-015 we indicated that energy storage procurement was an experiment; Finding of Fact 44 in D.13-02-015 stated: "A requirement to procure a modest level of energy storage resources, such as 50 MW provides an opportunity to assess the cost and performance of energy storage resources." The decision also provided ratepayer safeguards: Ordering Paragraph 12 provides, in part, that SCE: "shall present contracts for at least 50 MW of energy storage resources … to the Commission for approval, or have the burden to show that it should procure less than 50 MW because the bids it received were unreasonable."

We agree with SDG&E, SCE and the ISO that the energy storage targets adopted in D.13-10-040 cannot be assumed to count toward LCR need on a megawatt-for-megawatt basis. We confirm the intent of D.13-10-040 to jumpstart the use of energy storage resources in California. We strongly believe energy storage will be useful to meet LCR resources in the future; in general, we expect

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133 Exhibit CEJA-1 (May); at 54.

134 Sierra Club Opening Brief, at 11-14.

development of these resources to have an environmentally beneficial impact on energy supply and reliability in California.

D.13-10-040, Ordering Paragraph 3, orders SCE and SDG&E (as well as PG&E) to file applications containing a proposal for procuring energy storage resources by March 1, 2014, with the solicitation to occur no later than December 1, 2014. Ordering Paragraph 4 of that decision requires these utilities to file applications for future biennial energy storage procurement periods in 2016, 2018 and 2020, with any proposed modifications based on data and experiences from previous procurement periods. Much more will be known about procurement of energy storage resources and their impact on reliability as these processes develop.

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. At the same time, the targets and requirements of D.13-10-040 lead to a conclusion that energy storage resources will reduce LCR needs in the SONGS service area in the future. While we cannot quantify the LCR effect of potential energy storage resources, we conclude that it is reasonable to consider this potential as a directional indicator. In other words, this gives us more confidence that it is not necessary at this time to authorize the utilities to procure all of the resources indicated to be necessary in the ISO's study.

3.3.10. Energy Efficiency

SDG&E assumed 338 MW of energy efficiency peak reductions on a hot summer peak load basis.[135] Specifically, SDG&E reduced the load in its model by the mid-case forecast for uncommitted energy efficiency amounts adopted in the 2012 LTPP planning assumptions. This reduction is different than the one used by the ISO in its study. The ISO used the low-case uncommitted energy efficiency amount in the 2012 LTPP planning assumptions, per the revised Scoping Memo, which called for 187 MW of energy efficiency peak reductions.[136]

NRDC agrees with SDG&E's methodology, arguing that the Commission should reduce ISO's need estimates by 152 MW (338 minus 187, with rounding) in the San Diego local area because the evidence in this proceeding demonstrates that the revised Scoping Memo mistakenly assumed that SDG&E's local area was different from its service territory area. The revised Scoping Memo directed the ISO to use the "low level of [energy efficiency] savings for use in this set of studies" in SDG&E's local capacity area.[137] Normally, the low estimate would be used to account for the uncertainty of locational impacts of energy efficiency within a utility's service area.[138] As NRDC's witness Martinez testified, "The amount included in the local area should simply be the amount reasonably

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135 Exhibit SDG&E-1 (Anderson), at.10.

136 May 21, 2013 revised Scoping Memo in R.12-03-014, Attachment A, at 4.

137 Scoping Memo, Attachment A at 4.

138 Scoping Memo, Attachment A at 4. "When the service territory of a large utility that has areas both inside and outside a local capacity area is unlikely to have savings spread completely evenly throughout the territory, the CPUC will make a low savings estimate of energy efficiency to account for the possibility that the local capacity area might not get a proportional share of territory-wide savings; a "mid" estimate would reflect the CEC's best estimate across the entire territory. "

expected to occur in SDG&E's service territory, since they are the same geographical area."[139]

We agree with SDG&E and NRDC that the revised Scoping Memo should have used a different methodology with the mid-level energy efficiency estimate. The revised Scoping Memo stated: "across the SCE and SDG&E areas we expect the mid-level of savings to occur."[140] The revised Scoping Memo erroneously decreased energy efficiency estimates by assuming that the SDG&E service territory was not the same as the SDG&E portion of the SONGS service area. This is incorrect: they are one and the same. SDG&E properly applied the mid case estimate of 318 MW in its study.[141] Because we have data from SDG&E showing the LCR difference for the more appropriate mid-level energy efficiency estimate, it is reasonable to adjust the ISO study results by 152 MW.[142]

3.3.11. Solar Photovoltaic (PV)

The revised Scoping Memo designates incremental customer-side solar PV as a 'second contingency' resource because it is difficult to predict the location where customer-side PV will get built. The revised Scoping Memo directs the ISO to determine the most effective busbars where customer-side PV should be located in order to address those contingencies: "[o]nce those locations are

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139 Exhibit NRDC-1 (Martinez), at 11-12.

140 Revised Scoping Memo, Attachment A, at 4.

141 Exhibit SDG&E-1 (Anderson), at 5.

142 We note that this is the one exception we will make to the assumptions in the revised Scoping Memo, as this adjustment is due to an error and the LCR adjustment is clearly available in the record.

identified, the Commission can then direct customer-side generation programs, like the California Solar Initiative or other efforts, to target those locations."[143]

ISO witness Sparks testified: "The incremental small PV is actually a load modifier, it's typically behind the meter; and again, because it's not really known where the locations are, it was not included either. Not to say that it couldn't be used to meet the need if the characteristics are appropriate and it becomes more certain."[144]

CEJA contends that by 2022, with the likely implementation of smart inverters and a smarter grid in general, distributed generation such as customer side PV will provide manageable power located in the affected area that can reduce peak loads, reduce transmission line loss, and provide ancillary services such as reactive power and voltage support.[145]

CEJA may be correct about what will occur in the future; we are confident that our programs and the marketplace will increase the amount of solar PV in the future. However, we have no specific data or analysis in the record to determine where solar PV will locate, or the impacts of solar PV on LCR needs. We are hopeful that solar PV can be useful in reducing LCR needs in the future, but it is too speculative to make any changes to the ISO study results on this basis at this time.

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143 Revised Scoping Memo, at 10.

144 RT 1456.

145 CEJA Opening Brief, at 43.

3.3.12. Living Pilot

SCE describes its plan for an aggressive pursuit of preferred resources through the "Preferred Resource Living Pilot Program" (Living Pilot) in the vicinity of the Johanna and Santiago substations in the LA Basin (these substations are in Orange County, in the west LA portion of the LA Basin). The purpose of the Living Pilot is to aggressively pursue energy efficiency, demand response and distributed generation resources in this high impact area. SCE intends to use the Pilot to demonstrate the value that preferred resources can contribute to meeting LCR needs.[146] SCE anticipates that development of the Pilot will be a collaborative process undertaken with substantial input from the ISO and other stakeholders.[147] SCE is not seeking approval of the Living Pilot in this proceeding; SCE intends to file a future application on this topic.

As the Living Pilot is not before us at this time, we cannot make any determination about its viability or ability to meet LCR needs in the LA Basin.[148] To the extent that new resources are eventually procured through this effort, we will need to look closely to determine how they interact with other

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146 Exhibit SCE-1, at 52.

147 Exhibit SCE-1, at 51.

148 In order to support the implementation of the Living Pilot while still maintaining local reliability should the Living Pilot not achieve its goals, SCE states that it plans to develop gas-fired generation sites near the Johanna and Santiago substations. SCE states that it will work to obtain the necessary sites and associated permits; these sites would only be utilized only if the Pilot is unsuccessful and an LCR need continues to exist. If a contingency arose, SCE would put the sites out to bid to Independent Power Producers (IPP). The successful IPP would be awarded a power purchase agreement to finish the development of the project. SCE is not requesting approval of this plan at this time. SCE plans to file an Application with the Commission which will provide additional information regarding contingency siting. We do not opine about these potential contingent site development plans at this time.

authorizations (e.g., do Living Pilot procurements count toward SCE's LTPP preferred resources requirements?). At the same time, in concept the Living Pilot is promising both as a way to meet LCR needs and as a laboratory for innovation regarding preferred resources. We intend to take a close look at the Living Pilot when SCE files its application. For now, we simply note that projects which may become part of the Living Pilot may have the potential to reduce the need for other resources to meet LCR needs in the LA Basin. [149]

In addition, we strongly encourage SDG&E to pursue its own Living Pilot, or a tailored version of it. When asked by Commissioner Florio whether, if the Commission requested SDG&E could do something similar to SCE's preferred resources RFO or Living Pilot, SDG&E witness Anderson testified: "I'm sure if the Commission asked, we will find a way to do it."[150] SDG&E should consider this decision as the Commission's request.

4. Need Determination

The only party to recommend a local capacity requirement (LCR) need level at or above the amount in the ISO study, without any downward adjustment at this time, is PG&E. PG&E recommends adopting an identified, incremental LCR need of 5,070 MW in southern California. PG&E recommends this adopted incremental LCR need "should not be artificially reduced by assuming that other not-yet-approved generation and transmission projects will come to fruition." PG&E recommends adopting an incremental LCR need for SCE of 3,300 MW of resources, and an incremental LCR need for SDG&E of

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[149] The Commission held a Symposium on the SCE Living Pilot concept on November 6, 2013.

[150] RT 1815-16.

1,770 MW of resources. PG&E would count toward these procurement amounts Commission authorizations for "all incrementally procured resources that have been demonstrated to be effective in meeting the identified incremental LCR need including." These would include (at some point), resources procured by SCE in response to the Track 1 authorization (D.13-02-015) and by SDG&E in response to the D.13-03-029 authorization now approved in D.14-02-016, as well as transmission solutions verified to reduce local reliability needs without building new generation and on track to be completed in the necessary timeframe.[151]

In D.13-02-015, Finding of Fact 7, we addressed concerns about over-procurement and under-procurement: "Both under-procurement and over-procurement entail significant risks. Under-procurement entails risks of reliability problems and the impacts of mitigating such problems in a short timeframe. Over-procurement entails risks of excessive costs and unnecessary environmental degradation. It is not possible to quantify whether the risks of over- or under-procurement are greater." In Finding of Fact 32 in that decision, we stated: "A maximum LCR procurement level will protect ratepayers from excessive costs resulting from potential over-procurement." We continue to be concerned about the potential excess ratepayer costs resulting from over-procurement.

PG&E's recommendations carry a significant risk of over-procurement. PG&E does not adequately take into account the likelihood of various supply or demand considerations which are either very likely or reasonably likely to occur;

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151 PG&E Opening Brief, at 2-3.

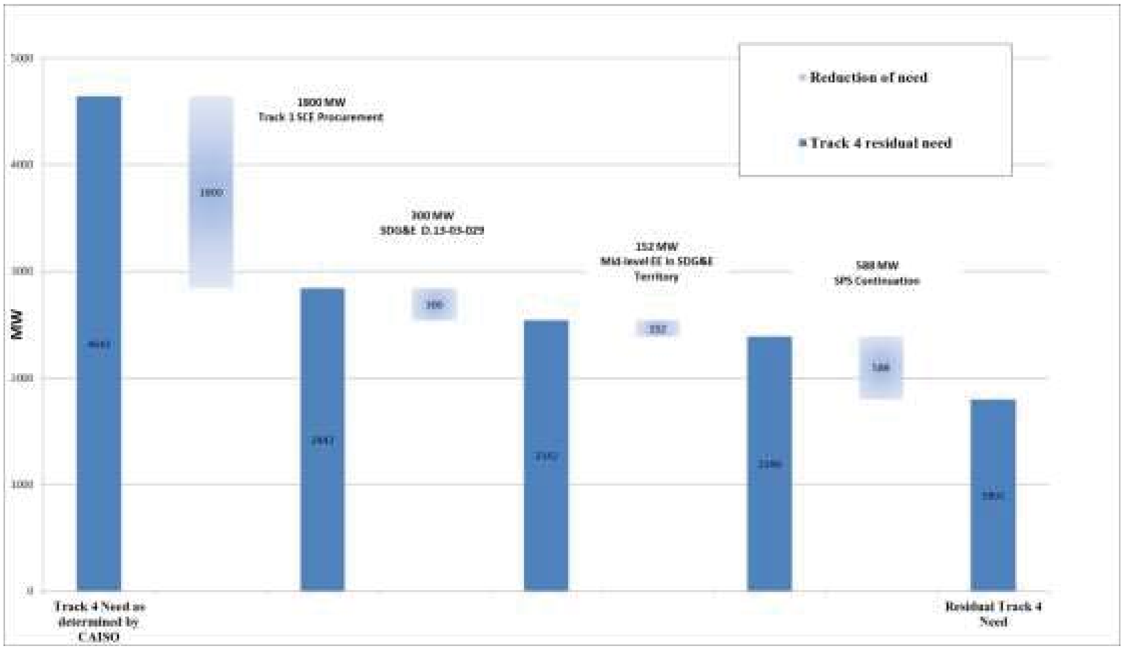
these factor will lower the overall need from the levels modeled by the ISO. PG&E's recommendations also would empower SCE and SDG&E to determine on their own whether further procurement is needed through 2022 in the SONGS service area, beyond amounts authorized in a limited number of Commission decisions. We are not convinced that it is either reasonable or prudent to grant such latitude to the utilities; we note that neither SCE nor SDG&E seek such broad authority. While the procurement objectives of utilities are often aligned with the public interest (e.g., ensuring reliability, consistency with environmental statutes), utilities may also have objectives (e.g., additions to rate base, competitive concerns) that differ from the public interest. Such divergent interests may result in higher ratepayer costs than with more close regulation.

Based upon the foregoing analysis, there is a wide range of possible reasonable and prudent outcomes. We find that the highest reasonable need level must take into account those resources which are very likely to be procured in the time frame between now and 2022. These include the full Track 1 authorizations for SCE (1,800 MW), and the D.13-03-029 and D.14-02-016 authorizations for SDG&E (300 MW). Further, we find that it is reasonable at this time to authorize procurement of at least 588 MW fewer resources than would be necessary to achieve the ISO's current reliability objective, with the understanding that actual load shedding would be a very remote possibility and that the ISO has the authority to continue the current SPS in the San Diego area. We leave open the possibility that additional resources may need to be procured to maintain consistency with ISO transmission policy over the long run, while noting that ISO transmission planning policy may evolve over time. We also find it reasonable to reduce the required LCR procurement level by 152 MW to properly take into account the mid-level energy efficiency forecast in the SDG&E local area.

Taking these very likely or certain modifications into account, the highest prudent level of procurement authorization for the SONGS study area would be 1,802 MW (rounded to 1,800 MW). This calculation is based on the ISO's high starting point of 4,642 MW (based on 80% of resources in the SCE territory), subtracting out SCE Track 1 authorization (1,800 MW), SDG&E's D.13-03-029/D.14-02-016 authorization (300 MW), a potential continued SPS in San Diego (588 MW) and the adjustment for mid-level uncommitted energy efficiency (152 MW). (*See* Chart 1.)[152] Any level above this amount entails too high of a possibility of over procurement. However, it would also be prudent to authorize a lower level of procurement to the extent that other resources that are reasonably likely to be procured are considered, even if their LCR impacts cannot be precisely measured.

[152] Starting from the ISO's lower starting point of 4,500 MW (based on 67% of resources in the SCE territory), the maximum level would be approximately 1,650 MW.

Chart 1
Maximum Procurement Calculation



We have identified a number of resources, at least some of which are reasonably likely to be procured in the SONGS study area by 2022 outside of this procurement proceeding. These include additional transmission (in particular, the Mesa Loop-In), demand response, energy efficiency, solar PV and energy storage resources. In addition, while it is speculative to consider the impacts of resources such as reactive power support, if such resources are available and effective at the right place and in a timely manner, they would have the impact of lowering LCR needs. Further, the future Living Pilot may add additional resources. We find that it is unreasonable to assume that <u>none</u> of these resources will be procured and able to meet local reliability needs in the SONGS service area by 2022. While the exact levels of procurement of these resources via other Commission proceedings, other agency requirements, and various market processes cannot be known with any certainty at this time, assuming that none of these potential resources will be available would not be prudent because it would most likely lead to over-procurement. In our judgment, it is reasonable to assume that <u>at least</u> between 10% and 20% of these resources will be available, in some combination.

Therefore, we find that there is a range of reasonable need levels that we can consider to be prudent.[153] This high end of the range is approximately 1,800 MW; authorization of this level of resources at this time would be the most conservative (but still prudent) action we could reasonably take in terms of reliability – but also the most costly in terms of procurement and most likely the least environmentally sensitive.

It is important to note that the methodology to determine the outer edges of a reasonable procurement range in this decision may not be the only reasonable methodology. In order to test the robustness of our determination that 1,800 MW is the maximum prudent level of procurement that should be authorized at this time, it is useful to consider alternative assumptions. For example, an alternative analysis might determine that we should authorize procurement consistent with the recommendation of the ISO and other parties regarding load-shedding and an SPS (thus not subtracting 588 MW), but at the same time assume that the Mesa Loop-In project would be viable (thus subtracting 734 MW). Or, that we should authorize procurement of 588 MW to fully avoid the N-1-1 contingency, but agree with NRDC that more aggressive

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[153] SDG&E witness Anderson requested flexibility in the utility's request, "We don't know the numbers this precisely. We ought to have some range to be flexible given the size of bids and the size of power plants." (RT 1845.)

energy efficiency assumptions worth up to 733 MW[154] are appropriate. As another possibility, we could have determined that some or all of the 'second contingency' demand response adjustments worth 800 MW should be accounted for.

In determining an alternative maximum prudent procurement amount, determinations should not incorporate more than one potential source to meet or reduce LCR needs into the analysis. In other words, we should consider, for example, whether <u>either</u> not to procure capacity to fully avoid the N-1-1 contingency <u>or</u> whether to assume another resource (or combination of partial achievements of resources) should be counted – but not both. Otherwise, there is too great a likelihood of under-procurement because of the risk that various uncertain or speculative resources will not materialize.

Table 2 shows the upper bound of a reasonable procurement range under different assumptions. Per Chart 1 above, the maximum procurement level is 2,390 MW before the 588 MW adjustment related to load-shedding policy. With various alternative assumptions, the maximum procurement level varies from 1,800 MW (our determination) down to 1,393 MW. Therefore, this sensitivity analysis allows us to confidently conclude that, under either the facts we find today or other reasonable sets of facts, the upper bound of procurement that should be authorized today should in no case be higher than 1,800 MW, and that levels between 1,393 and 1,800 MW could potentially be considered excessive. However, we again note that there is no operational data to determine LCR

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[154] NRDC calculates 885 MW of energy efficiency capacity that is not included in the ISO models. However, we subtract for 152 MW of this total in our analysis. The difference is 733 MW.

effectiveness for uncommitted energy efficiency, energy storage, 'second contingency' demand response or total 'second contingency' solar PV. Therefore, a reasonable maximum procurement level should be somewhere between 1,393 and 1,800 MW.

As a check on this methodology, the total of possible resources or assumptions identified by parties included in Table 2 that were not studied by the ISO equals about 4,600 MW. The range of reasonable maximum procurement levels takes into account between 588 and 997 MW of this 4,600 MW, or between 13% and 22% of 4,600 MW. This is very close to our judgment that, in some combination, approximately 10% to 20% of resources will be available, at a minimum. For the purpose of calculating a maximum procurement level, it is reasonable to assume that at least 13% - 22% of the resources or assumptions in Table 2 will ultimately be available to meet or reduce LCR needs in the SONGS service area by 2022.

Table 2
Maximum Procurement Range

Assumed adjustment to 2390 MW Need	**Impact On Need**	**Derived Upper-bound of Procurement Needed**
Temporary Load-shedding	-588 MW	1802 MW
Mesa-Loop in Transmission Project	-734 MW	1656 MW
Uncommitted EE	-733 MW	1657 MW
Energy Storage	-745 MW	1645 MW
Second contingency Solar PV	-800 MW	1590 MW
Second contingency DR	-997 MW	1393 MW

A minimum procurement level must also be defined. Several environmental and ratepayer parties (e.g., NRDC,[155] CEJA,[156] Sierra Club,[157] EDF,[158] CLECA[159])[160] recommend no procurement at this time, based on their analysis that there are likely to be sufficient resources available (and reductions in demand) to obviate any LCR need in the SONGS study area through 2022.[161] We disagree. Our concern in D.13-02-015 included the reliability risks of under-procurement. The analysis in the above sections shows that it is not reasonable to assume that most or all of these resources (or the SCE and potential SDG&E Living Pilots) counted by these parties will be fully procured and in place by 2022, and will meet or reduce LCR needs. For example, even in the unlikely event that all of parties' proposed highest amounts of 800 MW of 'second contingency' demand response resources or 733 MW of remaining 'naturally-occurring' energy efficiency were to exist, the actual LCR impacts are certain to be less than these MW amounts.

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155 NRDC Opening Brief, at 1.

156 CEJA Opening Brief, at vii.

157 Sierra Club Opening Brief, at 2.

158 EDF Opening Brief, at 3.

159 CLECA Opening Brief, at 2.

160 EnerNOC recommends no incremental procurement for SCE at this time, but does not oppose SDG&E's recommendation. EnerNOC Opening Brief, at 13, 14.

161 Other parties, such as CEERT, recommend no procurement authorization at this time for procedural reasons. For example, CEERT argues "The Commission should find that…the current record in Track 4 does not justify any "interim" Track 4 authorization for SCE or SDG&E by January or Q1 2014, especially without consideration of those near-term changes in key assumptions, and, instead, Track 4 should be the subject of a "holistic" final decision that can be issued on a timely basis as early as June or July 2014." (CEERT Opening Brief, at v.)

We have determined that it is reasonable to assume that some combination of these and other (e.g., energy efficiency, energy storage) resources will be available and will mitigate LCR needs, however it is not reasonable to assume this will be true for all (or even most) of these resources. Therefore, while it is mathematically possible to construct an analysis using a series of optimistic assumptions about resource availability that could lead to a finding of zero need (or negative need, which would indicate a surplus through 2022) at this time,[162] we find that a conclusion of zero need is not reasonable. A finding of zero need would not be prudent because it would most likely lead to under-procurement.

At the same time, between all the various resources and assumptions considered in this decision, there are potentially far more than 1,800 MW of additional resources that may be procured and meet or reduce LCR needs by 2022 in the SONGS service area (for example, we have identified 4,600 MW in Table 2). It is not prudent to assume that all of these resources will actually be effective and available at the right places and at the right time. In addition, in most cases we do not have sufficient information in the record to determine the LCR impact of such resources, because no party included these resources in their studies.[163]

A prudent analysis of the minimum procurement levels at this time should take into consideration a higher level of reasonably likely resources than

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162 For example, Sierra Club calculates a surplus of at least 488 MW. Sierra Club Opening Brief, at 16.

163 As discussed herein, SDG&E and SCE calculated the LCR impacts of certain transmission projects. However, these projects are not yet approved by the ISO and (even if approved and ultimately constructed), completion dates are uncertain.

included in maximum procurement levels. As a proxy for calculating a minimum LCR need level we can calculate the LCR impact if any two of the most likely potential scenarios (load-shedding, Mesa Loop-In, additional energy efficiency impacts, 'second contingency' demand response, solar PV, energy storage) should occur.[164] This methodology is roughly parallel with the ISO's N-1-1 analysis for LCR needs, which considers the loss of the two largest contingencies, and might be considered an "N+1+1" analysis (although a less rigorous endeavor). It is worth noting that another way of looking at this analysis is that <u>some</u> combination of scenarios could substitute for <u>some</u> LCR reduction from other scenarios. It is not useful or necessary to evaluate all possible scenarios to consider a minimum analysis. Analyzing 100% availability of any two scenarios is a reasonable proxy for the largest amount of available LCR reductions.

Table 3 illustrates a similar methodology as used to consider the reasonable maximum procurement range, starting with a base of 2,390 MW and subtracting for various potential resources not included in the ISO modeling. Table 3 shows that, in each case of 100% availability of any two scenarios not included in the ISO's modeling, the lower bound ranges from 593 to 1,067 MW. Therefore, this analysis allows us to confidently conclude that, under either the facts we find today or a reasonable sensitivity analysis, the lower bound of procurement that should be authorized today should in no case be lower than 593 MW. To be certain that the amounts authorized today will not result in

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164 Assuming for the sake of discussion that, when not studied, a MW decrease in demand equals a MW decrease in LCR needs. In reality, demand reductions are likely to result in less than a one-to-one decrease in LCR needs. This suggests that the minimum procurement level should be higher than calculated in this analysis.

under-procurement, the minimum authorized procurement level should be no less than 593 MW. Authorization of this level of resources at this time would be the most conservative action we could reasonably take in terms of procurement cost and environmental sensitivity – but would be the most risky in terms of reliability.[165]

However, we once again note that there is no data to determine LCR effectiveness for uncommitted energy efficiency, energy storage, 'second contingency' demand response or total 'second contingency' solar PV. Therefore, a reasonable minimum procurement level should be somewhere between 593 and 1,067 MW.

Another way of looking at this methodology is that the total of all possible resources or assumptions identified by parties (and which are included in Table 2) that were not studied by the ISO equals about 4,600 MW. The range of reasonable minimum procurement levels takes into account between 1,322 and 1,797 MW of this 4,600 MW, or between 29% and 39% of 4,600 MW. This is approximately double the minimum level of resources we judge to be available, in some combination. For the purpose of calculating a minimum procurement level, it is reasonable to assume that at least 29% and 39% of these resources or assumptions will ultimately be available to meet or reduce LCR needs in the SONGS service area by 2022.

[165] There are significant costs involved in any degradation of reliability. The section in this decision on SPS and load-shedding provides a partial discussion of such costs.

Table 3
Minimum Procurement Range

Assumed adjustment to 2390 MW Need	Impact on Needed Procurement	Procurement Still Needed
Load-shedding (588) + Mesa Loop-in (734)	-1322	1068
Load-shedding (588) + Uncommitted EE (733)	-1321	1069
Load-shedding (588) + Energy Storage (745)	-1333	1057
Load-shedding (588) + Second Contingency Solar PV (800)	-1388	1002
Load-shedding (588) + Second Contingency DR (997)	-1585	805
Mesa-Loop In (734) + Uncommitted EE (733)	-1467	923
Mesa-Loop In (734) + Energy Storage (745)	-1479	911
Mesa-Loop In (734) + Second Contingency Solar PV (800)	-1534	856
Mesa-Loop In (734) + Second Contingency DR (997)	-1731	659
Uncommitted EE (733) + Energy Storage (745)	-1478	912
Uncommitted EE (733) + Second Contingency Solar PV (800)	-1533	857
Uncommitted EE (733) + Second Contingency DR (997)	-1730	660
Energy Storage (745) + Second Contingency Solar PV (800)	-1545	845
Energy Storage (745) + Second Contingency DR (997)	-1742	648
Second Contingency Solar PV (800) + Second Contingency DR (997)	-1797	593

We next consider the recommendations of the parties about what amounts should be authorized to fill identified needs, other than PG&E (which recommends above the upper level of prudency) and those parties recommending zero procurement at this time (below the lower level of prudency).

As a starting point, the ISO's August 5, 2013 study yielded a resource need of 612 MW for SDG&E (after consideration of D.13-03-029 authorization of 300 MW) and up to 1,922 MW for SCE, depending on the portion of the LCR study identified need being allocated to the LA Basin and after deducting Track 1 authorization. However, this is not the ISO's recommended procurement level.

SCE and SDG&E each submitted testimony on August 26, 2013 based on power flow studies that reflected transmission upgrades, including reactive power resources, not studied by the ISO. SCE and SDG&E began their studies in advance of the revised Scoping Memo; accordingly, the utilities' assumptions are not identical to those used in the revised Scoping Memo.[166] However, SCE and SDG&E analyzed several scenarios, as shown in Exhibit 1 (the Joint Comparison Exhibit).

Considering all of its scenarios as well as the ISO's forecasts, SCE recommends procurement of 500 MW in the LA Basin. SCE witness Nelson testified that "no new generation is needed to meet NERC Reliability Standards" at this time.[167] 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. Thus, SCE's calculation that no additional procurement is needed at this time in its territory appears consistent with this determination. However, SCE's study assumed that the Mesa Loop-In transmission project would be approved and completed by 2022, thereby reducing LCR needs by 734 – 1,200 MW (depending upon if load shedding is allowed through an extended SPS in the SDG&E territory). We do not make this assumption about the Mesa Loop-In project. Therefore, SCE's recommendation to authorize 500 MW in the LA Basin is consistent with a policy decision to not authorize resources to meet all N-1-1 criteria at this time.

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[166] Exhibit SDG&E 1 (Anderson), at 2.

[167] Exhibit SCE-1 (Nelson), at 6.

SDG&E's technical studies calculate a need for at least 1,028 MW of new local resources between now and 2022 in the San Diego area.[168] SDG&E's minimum base case analysis assumed 408 MW of load reduction/resource additions from incremental preferred resources above current levels (prior to running the transmission models), which effectively reduces minimum local need in the SDG&E sub-area to 620 MW (1,028 MW minus 408 MW).[169] Thus, SDG&E has identified in this Track 4 a minimum need for new local resources in the San Diego sub-area of between 620 MW and 1470 MW by 2022.[170] Of the 620 MW minimum need, SDG&E's procurement strategy holds 70-120 MW open to be filled with demand response and/or energy storage resources (consistent with ISO for operational characteristics that address local reliability needs). For the remaining need, SDG&E requests authority to procure 500-550 MW of long lead-time supply-side resources, including conventional generation and/or renewable resources.[171]

Redondo Beach performed its own technical studies, using power flow analysis. Redondo Beach claims that its studies used the same inputs and assumptions as the ISO. Redondo Beach recommends procurement of 1,140 MW

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[168] This analysis assumes Commission approval of SDG&E's A.13-06-015, which seeks authority to enter into a power purchase and tolling agreement with Pio Pico Energy Center for 300 MW of conventional generation.

[169] Exhibit SDG&E-1 (Anderson), at 9. The analysis assumes a "dependable" peak reduction of 338 MW of Energy Efficiency, 30 MW of rooftop solar and 20 MW of Combined Heat and Power resources. (*Id*., at 7, Table 1.) It also assumes 20 MW of dependable peak reduction associated with local renewable generation. (*Id*. at 11, Table 2.)

[170] Exhibit SDG&E-3 (Jontry), at 2.

[171] SDG&E Opening Brief, at 4.

in the LA Basin and 753 MW in the SDG&E area. For the LA Basin, Redondo Beach recommends all procurement be from preferred resources based on its studies.[172] SCE responds that, while Redondo Beach claims that their proposal is the only solution that addresses both the Western LA Basin sub-area as well as the greater SONGS area, the record shows that Redondo Beach only studied the Western LA Basin and did not perform a study to analyze the impacts on the greater SONGS study area.[173] We do not agree with SCE that Redondo Beach's study is incomplete in this regard. However, significant parts of Redondo Beach's studies rely on interpretations of N-1-1 contingencies that are at odds with the ISO's studies; we have already determined that we will defer to the ISO on this point. While we consider Redondo Beach's recommendations along with those of other parties, we will rely on the ISO study (as modified herein) as the better analytical tool.

The ISO now recommends approval of the recommendations of SCE and SDG&E:

> "Given the importance of maintaining reliability in this heavily populated, urban area of California, and the complex array of actions necessary to meet the residual needs identified by the [ISO], it is urgent for the Commission to authorize an all-source procurement for SCE and SDG&E for the amounts requested. This is much different, of course, than authorizing a comprehensive amount of procurement meant to address all the residual needs, which we advised against in Mr. Sparks' initial testimony."[174]

[172] Redondo Beach Opening Brief, at 1-4.

[173] SCE Reply Brief, at 47.

[174] Exhibit ISO-7, at 6.

In Opening Briefs, the ISO, TURN, CalWEA, Alton, CESA, WPTF, and Wellhead all support SCE's request for procurement authorization for an additional 500 MW in this Track 4.[175] In a change from its position in testimony (as reflected in Exhibit 1), ORA now recommends[176] that the Commission authorize procurement of between 1,315 and 1,450 MW, with 700 MW in SCE service territory and between 615 and 750 MW in SDG&E service territory.[177] TURN recommends that SCE and SDG&E each be authorized to procure up to 500 MW, plus or minus ten percent within their respective service territories to accommodate the potential "lumpiness" of transmission or generation investments (thus TURN's recommendation is for procurement authorization for 450 – 550 MW for each utility, or 900 – 1,100 MW in total). IEP recommends that the Commission should authorize an interim procurement of at least 706 MW for SCE and 820 MW for SDG&E.[178] CalWEA recommends procurement of 500 MW for SCE and 300 - 350 MW for SDG&E.[179] AES Southland recommends that the Commission authorize SCE to procure an additional 1,440 MW of generation,

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[175] ISO Opening Brief, at 33-34, TURN Opening Brief, at 1-2, CalWEA Opening Brief, at 1-2, Alton Opening Brief, at 3, WPTF Opening Brief, at 2, Wellhead Opening Brief, at 1-2.

[176] In its Opening Brief at 11, ORA also recommends that the Commission consider the ISO's 2013/2014 Transmission Planning Process in determining need for the SONGS study area.

[177] ORA Opening Brief, at 13-14.

[178] Exhibit IEP-1 (Monson), at 30.

[179] CalWEA Opening Brief, at 5.

based upon SCE's own need calculation, absent load shed, less the Track 1 procurement already authorized.[180]

Each of these parties' recommendations stem from modestly different methodologies, although each have in common certain subtractions from a total LCR need for procurement already authorized and calculations of expected resources. While varying in some aspects, each of these parties' recommendations fall within the prudent range of procurement we have identified for the SONGS service area: a number significantly greater than zero and less than 1,800 MW. The lowest recommendation of these parties is 800 MW for the SONGS service area, the highest is over 1,400 MW.

Similar to the Track 1 decision in this docket, we will authorize a procurement range. Authorizing a procurement range takes into account a) uncertainties about supply and demand conditions; b) the ability to process new information during the procurement process; c) the need to provide the utilities with flexibility to procure resources which may only be available in large increments; d) increases in requirements to procure preferred resources (as discussed below); and e) the need to provide utilities and the Commission with the ability to protect ratepayers by not forcing certain less economic procurement decisions.

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[180] AES Southland Opening Brief, at 5.

We have determined that the outer edges of a reasonable procurement range to be 593 MW to 1,800 MW, but that minimum procurement could be up to 1,067 MW and maximum procurement could be as low as 1,383 MW. The overall procurement level we authorize for the SONGS service area at this time is 1,000 - 1,500 MW. This range is consistent with the recommendations of many parties and is near the center of the overall zone of reasonableness. This range provides greater ratepayer protection against over procurement and simultaneously reduces the likelihood of any reliability impacts from under procurement.[181] These authorized amounts are not the full amounts needed to meet the LCR needs; a significant amount of future procurement in the SONGS service territory will come from the various resources analyzed herein. Further, there may be a need to authorize further procurement in future LTPP proceedings in the event of changes in supply and demand forecasts, to meet ISO reliability criteria, or if circumstances change significantly.

We accept the ISO's analysis that between 67% and 80% of procurement needed to address LCR needs in the SONGS service area by 2022 must be in the LA Basin, which is in SCE territory. The remainder would be in the SDG&E service territory. It is not possible at this time to discern how resources between the 1,000 – 1,500 MW amounts authorized today, and the approximately 4,500 – 4,600 MW level of total procurement need identified by the ISO, ultimately will be distributed between SCE and SDG&E territories. We already have determined that 1,800 MW will be procured from Track 1 by SCE, and 300 MW from D.13-03-029 for SDG&E; thus, over 85% of these authorized resources are

[181] Environmental considerations of procurement levels are addressed in Section 5 of this decision, where we determine the mix of resources to be procured.

already slated for SCE territory. Other opportunities are less clear. For example, it is possible the Mesa Loop-In project goes forward, but the SDG&E proposed transmission projects do not. In that case, at least several hundred MW more resources would be in SCE territory, necessitating a greater procurement requirement for SDG&E to retain a proper allocation. Because of several unknowns, authorized amounts today may need to be adjusted in the future to balance procurement between utility territories.

We authorize SCE to procure between 500 and 700 MW. We authorize SDG&E to procure between 500 and 800 MW. The greater maximum amount for SDG&E reflects several factors. First, SDG&E's recommendations include assumptions for transmission lines which we do not accept as reasonably likely (unlike the Mesa Loop-In for SCE). Second, even with its transmission assumptions, SDG&E's studies show a need for at least 1,028 MW in its territory by 2022. After assuming the Pio Pico plant, SDG&E shows a need for at least 728 W in its territory. Third, as discussed below, we will require SDG&E to procure more preferred resources than the 120 MW it contends are achievable (on top of 408 MW of preferred resources SDG&E expects to procure through other proceedings). In light of all of these factors, it is appropriate and prudent to allow SDG&E to procure up to 800 MW at this time to avoid under-procurement.

Given that the bulk of both total authorized and potential resources are expected to be in SCE territory, authorizing the same procurement range for both utilities should be consistent with the ISO's range that 67 - 80% total procurement needs to be in the SCE territory. In both cases, the high end of the range is above what the utilities requested, but within the range of prudent procurement established in this order. For both utilities, these authorized amounts are subject to conditions established herein.

We note that there are also additional safeguards to ensure that under procurement does not occur, beyond the various expectations for resource procurement discussed herein, and future LTPP proceedings. For example, ORA recommends that, notwithstanding California's commitment to meeting OTC compliance deadliness, the Commission should consider that limited extensions to OTC compliance deadlines of the most electrically effective OTC plant(s) may be available if needed to bridge a short-term gap between when resources are needed, and when they are available.[182]

In D.13-02-015, Finding of Fact 10 stated: "It is reasonable to assume that the OTC plants in the SCE territory required to comply with SWRCB regulations will comply through retirement or repowering consistent with the SWRCB schedule, for the purpose of LCR forecasting in this proceeding. However, no finding on this point is intended to apply to SONGS."[183] We do not revisit this Finding. At the same time, we agree with ORA's observation that it may be possible to extend OTC deadlines if it is necessary to ensure reliability. Any such action will occur through the appropriate process.

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[182] ORA Opening Brief, at 27.

[183] The reference to SONGS in this Finding of Fact was intended to reference SONGS as an OTC plant. In other words, there was no Finding of Fact about whether SONGS would remain in service, retire, or repower in any given timeframe.

5. Filling the Identified Need

5.1. Requirement for Procurement of Preferred Resources

At the time of the Track 1 decision in this proceeding, the permanent closure of SONGS was not anticipated or factored into the modeling considered in that track. As a nuclear power facility, SONGS has been subject to various safety and environmental concerns over the years, but SONGS did not emit any greenhouse gases during its time in service. To replace a zero emission facility like SONGS with other resources, several parties argue it is necessary to mandate only low-to-no emitting resources as a source of replacement capacity. NRDC, Sierra Club, CEJA, and EDF all urge that any procurement authorized by the Commission should include preferred resources only.[184]

Other parties point out that the complexities of maintaining reliability on the local grid require a sophisticated set of characteristics, which cannot always be met with preferred resources. A number of parties therefore recommend requiring procurement of preferred resources to the greatest extent possible, but providing the utilities with the opportunity and obligation to procure a mix of resources that balances fealty to the Loading Order with meeting grid requirements. For example, CEERT recommends that, consistent with the Loading Order and procurement proportions established in D.13-02-015, no more than 2/3 of the authorized maximum procurement levels should be met by conventional gas-fired resources; the remainder should be preferred resources.[185] Another group of parties – including SCE and SDG&E - recommend allowing the

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[184] NRDC Opening Brief, at 18-19; Sierra Club Opening Brief, at 1-3; CEJA Opening Brief, at vii; and EDF Opening Brief, at 7-8.

[185] CEERT Opening Brief, at 47-48.

utilities to use all-source RFOs to procure authorized resources on a least-cost/best-fit basis, thereby providing the utilities with the ability to choose the resource mix (subject to subsequent Commission approval).

The ISO endorses the idea that substantial portions of the local capacity needs created by the SONGS outage can be filled with preferred resources, with two caveats:

First, the Commission and parties must be diligent in moving ahead to develop the necessary programs that can participate with other supply-side resources (such as demand response) and that will provide load-shaping demand-side benefits (such as energy efficiency and small PV) with the necessary locational data that the ISO can use in its local area capacity studies to offset the need for conventional infrastructure.

> Secondly…the Commission must be diligent and expeditious in tracking the development of preferred resources in order to verify that they are actually materializing in the locations and amounts predicted in the studies and resource procurement efforts that established such forecasts.[186]

NRG points out that local generation must provide a suite of reliability benefits, such as: a) allowing for the regular maintenance of other generation or transmission within the local area; b) continuously following variations in demand or variable renewable generation; c) providing contingency reserve to respond to sudden changes in demand or the loss of a generating or transmission resource; d) maintaining transmission voltages within acceptable levels by producing or absorbing reactive power as needed; e) providing or standing by ready to provide real power output to maintain network flows within safe limits.

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[186] ISO Reply Brief, at 24.

Thus, NRG contends that relying on preferred resources to meet local area requirements and still provide the same level of reliability requires a complex analyses; most LCR needs are currently met by gas-fired resources.[187]

SDG&E also argues against mandating the use of all or nearly all preferred resources in this decision:

> While SDG&E strongly supports inclusion of preferred resources in its portfolio to serve bundled load…it does not perceive that a capacity procurement approach heavily skewed toward reliance on preferred resources is reasonable at this time, while there is still great uncertainty as to the ability of preferred resources to meet local capacity need. In short, placing all of SDG&E's eggs in the single basket of preferred resources is an imprudent planning approach which exposes ratepayers to unreasonable risk.[188]

Some parties contend that SCE and SDG&E should procure only preferred resources and energy storage because these resources can be developed significantly quicker than traditional gas-fired generation. SCE rebuts that it takes about seven years to develop gas-fired generation facilities in the LA Basin and it is now approximately seven years until new LCR resources are needed in 2020. SCE contends that

> "if the Commission authorizes preferred resource procurement only at this time, it is likely precluding gas-fired generation development to meet LCR need in 2020. If this occurs, then gas-fired generation will not even be an option to meet LCR need in 2020 (if it is needed) because it will not be able to be developed quickly enough. Choosing preferred resource procurement only, without any expedited approval of contingent site development and/or options PPAs, would

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[187] NRG Opening Brief, at 7 -8.

[188] SDG&E Reply Brief, at 10.

> likely reduce grid reliability in 2020. This is because the options to replace all OTC generating facilities, including SONGS, would be very limited."[189]

In D.13-02-015, Finding of Fact 30 stated: "It is necessary that a significant amount of this procurement level be met through conventional gas-fired resources in order to ensure LCR needs will be met." There is nothing in the record of Track 4 of this proceeding that would require a change to this Finding. While we strongly intend to continue pursuing preferred resources to the greatest extent possible, we must always ensure that grid operations are not potentially compromised by excessive reliance on intermittent resources and resources with uncertain ability to meet LCR needs.

In the Commission's RA proceeding (R.11-10-023), we are currently exploring the ability of various preferred resources and energy storage to meet LCR needs.[190] The ISO is engaged in this effort as well. As this highly technical process develops, we will have a better idea of how such resources can be integrated with gas-fired resources to ensure reliability. In addition, we will learn more about the extent to which non-gas-fired resources can be used instead of gas-fired resources to meet LCR needs. Until this effort is better developed, we will take a prudent approach to reliability, while still promoting preferred resources to the greatest extent feasible. The prudent approach we take entails a

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189 SCE Reply Brief, at 8.

190 In the August 2, 2013 Phase 3 Scoping Memo for R.11-10-023 (RA proceeding), the scope of the proceeding includes: "In workshops and comments, stakeholders will develop counting rules, eligibility criteria, and must-offer obligation for use-limited resources, preferred resources, combined cycle gas turbines, and energy storage resources for Commission consideration."

gradual increase in the level of preferred resources and energy storage into the resource mix, to historically high levels.

In the Track 1 decision, Ordering Paragraph 1 included the following requirements for SCE for its authorization to procure 1,400 to 1,800 MW:

a. At least 1,000 MW, but no more than 1,200 MW, of this capacity must be from conventional gas-fired resources, including combined heat and power resources;
b. At least 50 MW of capacity must be procured from energy storage resources;
c. At least 150 MW of capacity must be procured from preferred resources consistent with the Loading Order of the Energy Action Plan;
d. Subject to the overall cap of 1,800 MW, up to 600 MW of capacity, beyond the amounts specified required to be procured pursuant to subparagraphs (a), (b) and (c) above, may be procured through preferred resources consistent with the Loading Order of the Energy Action Plan (in addition to resources already required to be procured or obtain by the Commission through decisions in other relevant proceedings) and/or energy storage resources.

We will build upon the Track 1 approach in this decision. As discussed below, we authorize SCE to procure resources for both Track 1 and Track 4 pursuant to its Track 1 procurement plan as approved by Energy Division. This generally entails procurement of additional resources through SCE's already-issued RFO as well as bilateral contracts.[191] Combining Track 1 and Track 4, SCE is now authorized to procure up to 2,500 MW in the LA Basin. SCE proposes to add its additional requirement from Track 4 without any specification of resource type. However, this approach is not consistent with our stated goals here and in Track 1 to adhere to the Loading Order.

Under the terms of the Track 1 decision, if SCE procured the minimum 1,400 MW of total resources, between 200 and 400 MW (or 14% to 29%) would be from preferred resources or energy storage. If SCE procured the maximum 1,800 MW of total resources per that decision, between 600 and 800 MW (33% to 44%) would be from preferred resources or energy storage.

In this decision, we authorize SCE to procure between 1900 MW (the 1,400 minimum from Track 1 plus the 500 minimum from Track 4) and 2,500 MW (the 1,800 maximum from Track 1 plus the 700 maximum from Track 4). Under SCE's approach, SCE could procure as much as 1,700 MW from gas-fired generation: 1,200 MW per Ordering Paragraph 1a in D.13-02-015 plus 500 MW from this decision. If SCE procured the overall minimum amount, between 200 and 900 MW of the 1,900 MW minimum procurement authorization (11% to 47%) would be from preferred resources or energy storage. If SCE procured the

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[191] In addition, Ordering Paragraph 9 of D.13-02-015 states: "Southern California Edison Company is authorized to procure bilateral cost-of-service contracts to meet authorize local capacity requirements as specified in this Order, including bilateral contracts consistent with the provisions of Public Utilities Code § 454.6."

overall maximum amount, between 600 and 1,500 MW of the 2,500 MW minimum procurement authorization (24%to 67%) would be from preferred resources or energy storage.

SCE's proposal would expand the range of potential procurement of preferred resources and energy storage. On the other hand, SCE could procure up to 89% of authorized resources from gas-fired generation. It is not clear what would actually occur; under its proposal, SCE would control the procurement process consistent with its Track 1 procurement plan. Assuming SCE pursues a least-cost/best-fit approach to the increased discretionary portion of procurement authority[192] (the additional 500 – 700 MW), it is likely that SCE would procure mostly gas-fired resources if such resources are less costly than preferred resources. From a ratepayer perspective, this may be beneficial; however, the Loading Order calls for prioritization of cost-effective preferred resources, in some cases even if they are more expensive than other resources.

We will modify SCE's proposal to ensure that SCE procures a higher percentage of authorized resources from preferred resources and energy storage. For SCE (and SDG&E as delineated below), we will not require any specific incremental procurement from gas-fired resources. This means that all incremental procurement as a result of this decision may be from preferred resources. At the same time, we will not modify the requirements from D.13-02-015 that some procurement must be from gas-fired resources in order to ensure reliability. Further, to provide a level of flexibility to utilities and to

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[192] SCE Reply Brief, at 9 ("SCE will use least-cost/best-fit criterion to 'obtain a cost-effective mix of resources to meet SCE's LCR needs in a manner consistent with the Preferred Loading Order.'"). Also *see* Exhibit SCE-2, at 22.

ensure procurement consistent with ISO reliability standards, we will expand the range for both gas-fired resources and preferred resources (as well as energy storage).

SCE is authorized to procure resources as follows, as shown in Chart 2:

a. At least 1,000 MW, but no more than 1,500 MW, of local capacity must be from conventional gas-fired resources, including combined heat and power resources;

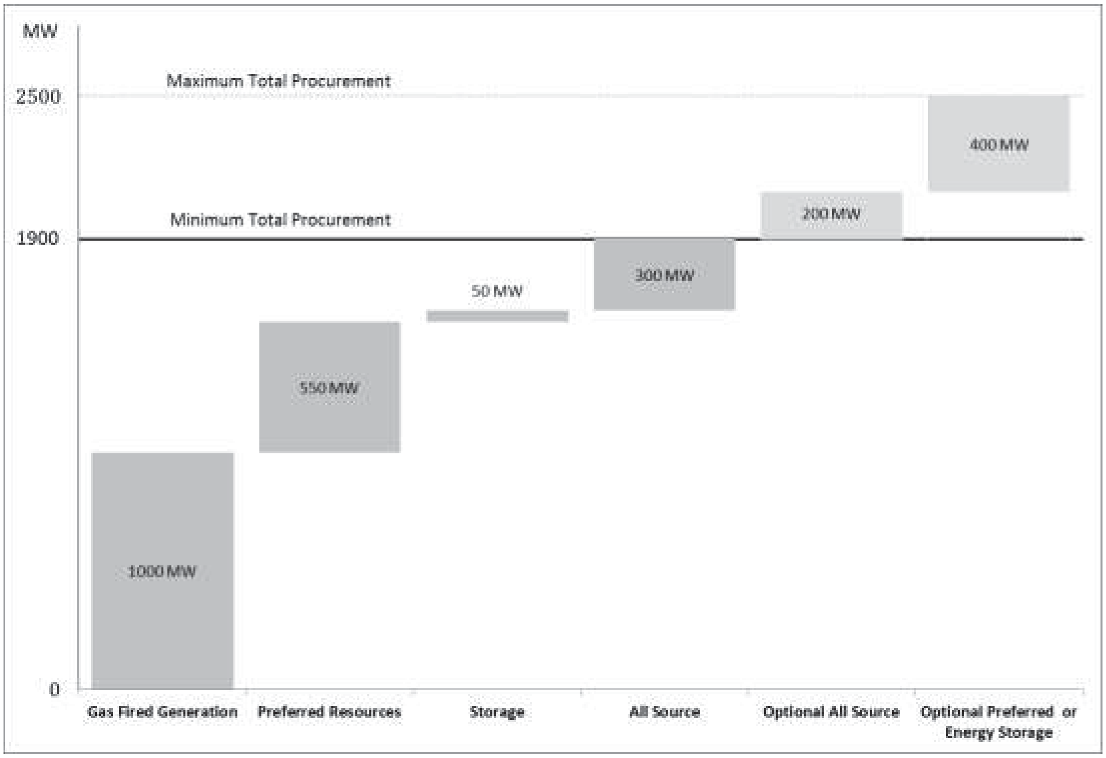
b. At least 50 MW of local capacity must be procured from energy storage resources (as defined in D.13-10-040);

c. At least 550 MW of local capacity must be procured from preferred resources consistent with the Loading Order of the Energy Action Plan (beyond the requirement of subsection b of this Ordering Paragraph). Bulk energy storage and large pumped hydro facilities shall not be excluded.

d. At least 300 MW, but no more than 500 MW, of local capacity, beyond the minimum amounts specified in subparagraphs (a), (b) and (c), must be procured and can be from any resource able to meet local capacity requirements.

e. Subject to the overall cap of 2,500 MW, any additional local capacity, beyond the amounts specified in subparagraphs (a), (b), (c) and (d), may only be procured through preferred resources (including bulk energy storage and large pumped hydro facilities) consistent with the Loading Order of the Energy Action Plan. Such preferred resources shall be in addition to preferred resources already required by the Commission to be procured or obtained through decisions in other relevant proceedings, and/or energy storage resources.

Chart 2
SCE Authorized Procurement
Track 1 + Track 4



This method ensures that at least 400 MW of the additional procurement authorized by this decision will be obtained through preferred resources or energy storage. In total, SCE is now authorized to procure between 400 and 1,500 MW from preferred resources or energy storage, up from 200 to 800 MW in the Track 1 decision. If SCE procures the minimum 1,900 MW of total resources, between 21% and 47% will be from preferred resources or energy storage. If SCE procures the maximum 2,500 MW of total resources, between 40% and 60% will be from preferred resources or energy storage.

SDG&E seeks to issue an all-source RFO or to contract bilaterally. SDG&E contends that moving forward on an expedited basis with a bilateral contract to address a portion of LCR need would support the policy goals of the State related to timely retirement of OTC facilities and would promote system reliability – the sooner new local resources are added to the portfolio, the lower the reliability risk.[193] SDG&E expects that 50 to 120 MW will be procured from preferred resources and energy storage.

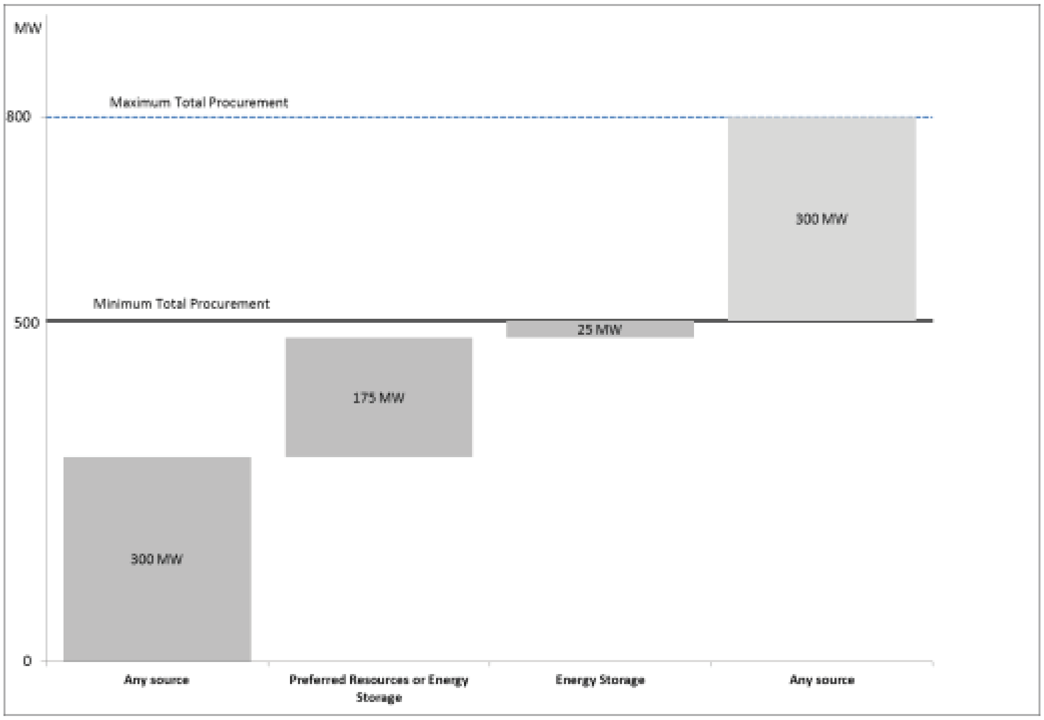
There are no requirements from D.13-03-027 for specific resource procurement amounts to meet SDG&E's LCR needs; however, SDG&E now has been approved to fill the authorized 300 MW from the gas-fired Pio Pico project. We will take a similar approach for SDG&E as for SCE. We approve SDG&E's proposal to issue an all-source RFO or enter into bilateral contracts for the additional 500 – 800 MW authorized herein. SDG&E proposes that it procure preferred resources through specific proceedings dedicated to these resources. We agree that SDG&E should continue to follow the Commission's requirements in other dockets; SDG&E already anticipates 407 MW will be procured in this manner. However, as with SCE, it is our intent that SDG&E should also pursue significant percentages of procurement to replace SONGS through preferred resources, energy storage and consistency with the Loading Order. Therefore, SDG&E shall ensure than no less than 200 MW of procurement authorized by this decision is from preferred resources or energy storage. This amount is higher than the 120 MW of preferred resources SDG&E recommends in this proceeding. We believe the record shows that SDG&E's recommendations are conservative. To the extent that SDG&E seeks to procure incremental preferred resources and energy storage (beyond those already expected to be procured elsewhere) through other procedural vehicles authorized by the Commission, it

[193] SDG&E September 30, 2013 Comments, at 5-6.

must delineated this process in its procurement plan (discussed below). To summarize, as shown in Chart 3:

a. At least 25 MW of capacity must be procured from energy storage resources;
b. At least 175 MW of capacity must be procured from preferred resources consistent with the Loading Order of the Energy Action Plan;
c. Subject to the overall cap of 800 MW, up to 600 MW of capacity, beyond the amounts specified required to be procured pursuant to subparagraphs (b) and (c) above, may be procured through any set of resources appropriate to meet LCR needs in the SDG&E territory, consistent to extent feasible with the Loading Order of the Energy Action Plan (in addition to resources already required to be procured or obtained by the Commission through decisions in other relevant proceedings).

Chart 3
SDG&E Procurement Authorization



Thus SDG&E may procure from 25%to 100% of additional resources authorized by this decision from preferred resources or energy storage. We provide this wider range of possibilities for SDG&E, as compared to SCE, because SDG&E is already approved to procure about 300 MW from gas-fired generation (Pio Pico). Now that the Pio Pico application is approved, SDG&E's total procurement for LCR purposes will be from 800 to 1,100 MW; thus SDG&E will be authorized to procure from 22%to 79% of additional resources from preferred resources or energy storage, a range reasonably similar to the 21% to 60% range for SCE discussed above.

5.2. Energy Storage

CalWEA contends that requiring SCE and SDG&E to fulfill their storage targets in the process of meeting Southern California's local reliability needs will lower the total cost of meeting both goals, given that the utilities are required to fulfill the storage targets within the 2020-2024 timeframe regardless of viability or cost-effectiveness.[194] SDG&E recommends that all energy storage be procured via the process contemplated in D.13-10-040 and LCR need reduced only to the extent energy storage is shown to meet local need.[195]

D.13-10-040 in section 4.5.3 states:

> "The procurement targets and the schedule for solicitations proposed here are not presently tied to need determinations within the LTPP proceeding. Instead, in the near term, we view the Storage Framework adopted herein as moving in parallel with the ongoing LTPP evaluations of need – system and local, and with the new consideration of the outage at SONGS. In the longer term, we expect that any procurement of energy storage will be increasingly tied to need determinations within the LTPP proceeding."

We do not modify the energy storage procurement targets established in D.13-10-040. It is too early to know if such targets are too high, too low or just right. More information will become available after the first utility solicitations; per D.13-10-040, Ordering Paragraph 3, applications containing a proposal for procuring energy storage resources are due by March 1, 2014, with the solicitation to occur no later than December 1, 2014. Nor will we modify the 50 MW energy storage requirement for SCE in D.13-02-015. That requirement

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194 CalWEA Opening Brief, at 7.

195 SDG&E Opening Brief, at 22.

will remain a part of the 1,900 – 2,500 MW combined authorization for Track 1 and 4 of this proceeding. Per D.13-10-040, this will partially meet the energy storage target for SCE. For SDG&E, we will establish a smaller 25 MW energy storage procurement requirement, which will partially meet the lower D.13-10-040 target for SDG&E. Similar to SCE, this new energy storage requirement for SDG&E shall be separate from the preferred resources requirements.

For both SCE and SDG&E, the set energy storage procurement requirements in this decision are minimum, not maximum, levels. Both utilities may also procure energy storage as part of their preferred resources requirements or all-source authorizations, subject to any other conditions in this decision.

5.3. Large Scale Pumped Storage (Bulk Storage) Procurement

D.13-10-040 at 30,34 excluded large-scale (50 MWs or more) pumped storage projects from the energy storage targets, reasoning that "the sheer size of pumped storage projects would dwarf other smaller, emerging technologies; and as such, would inhibit the fulfillment of market transformation goals." The decision at 35 further found that applicable statute indicated a legislative intent "to encourage a broad range of energy storage technologies" and, "to achieve this," placed "a limit on the size of pumped hydro storage systems eligible to participate in the particular mechanisms outlined in this decision." D.13-10-040 at 33 identified this LTPP Track 4 proceeding as the venue for providing a procurement mechanism for large-scale pumped or bulk storage, especially since that technology would have particular application in terms of addressing "local reliability impacts of a potential long-term outage at the SONGS." D.13-10-040 also states: "We strongly encourage the utilities to explore opportunities to partner with developers to install large-scale pumped storage projects where they make sense within the other general procurement efforts underway in the context of the LTPP proceeding or elsewhere."

According to ISO witness Sparks, if "it has the right characteristics," there is no basis to exclude "bulk storage" from being procured by SCE or SDG&E to meet a local capacity requirement in the absence of SONGS.[196] In addition, ISO witness Millar testified that "pump storage can be a very effective mitigation in meeting local needs, whether it's characterized as a preferred resource or not."[197] SCE witness Nelson testified that pumped storage "technology is fairly well understood" and "that there are some significant advances in controls and variable speed pumps that could add additional value to the grid."[198] While witness Nelson was uncertain about the "effectiveness" of "any large pumped hydro storage" in meeting the "West LA Basin LCR," he did believe it could be "bid in" for Track 1 and would contribute to the "balanced approach" of using "all resources" to avoid "the possibility of failure and being overly reliant on anyone."[199]

CEERT contends that large-scale (50 MW or more) pumped storage must be part of any procurement or RFO authorized by this Commission in this decision.[200] CEERT witness Caldwell testified: "[T]here are multiple pumped storage facilities under consideration in Northern San Diego County that could easily provide for LCR need found in Track 4, plus provide other significant grid

[196] RT 1544.

[197] RT 1655.

[198] RT 1917.

[199] RT 1916-1917.

[200] CEERT Opening Brief, at 51.

benefits."[201] ORA agrees that the Commission should ensure that SDG&E and SCE extend bid eligibility to include large scale pumped storage projects.[202] Eagle Crest recommends that nothing in this decision should preclude or restrict opportunities for the utilities to procure bulk energy storage, especially large pumped hydro facilities.[203]

As discussed herein, we require SCE and SDG&E to procure MW ranges of certain types of resources. Each utility should solicit all resources as required by this decision, and may propose for approval any set of resources which can meet the LCR need in its portion of the SONGS service area consistent with the authorized resource ranges herein. Within the categories that include preferred resources, bulk energy storage and large pumped hydro facilities should not be excluded. We have also set aside specific procurement amounts for energy storage. Within the energy storage category, we will limit procurement to the types of energy storage anticipated by D.13-10-040.

5.4. Contingency (Options) Contracts

In its testimony, SCE discussed a conceptual plan to potentially backstop SCE's procurement approach with contingent GFG contracts. The contingent GFG contracts (also known as options contracts) would require the seller to begin the process of developing a power plant, including the necessary pre-development work to site, permit, and construct a specified GFG resource.[204] SCE asserts this pre-development work will reduce development time, if

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[201] Exhibit CEERT-1 (Caldwell), at II-3.

[202] ORA Reply Brief, at 4.

[203] Eagle Crest Opening Brief, at 6.

[204] Exhibit SCE-1, at 58; RT 1960.

triggered, by two years. However, the entities would not begin actual construction of the power plant without SCE authorization. The contingent contract would contain a buyer's right to terminate the contract, and "SCE would only proceed with completing commercial operation of the contingent contract for GFG if a demonstrated need existed, and after receiving Commission approval to do so."[205]

SCE identifies several reasons for which a need to backstop SCE's procurement may arise: "(1) failure to successfully develop GFG procured in SCE's Track 1 LCR procurement process; (2) inability to develop sufficient Preferred Resources to meet SCE's Track 1 LCR procurement authorization; (3) planned local area grid enhancements are not completed; and (4) planning assumptions on the availability and effectiveness of resources do not materialize."[206] If a need did arise, SCE contends the contingent contracts would reduce the lead-time for developing GFG, thus improving grid reliability in the LA Basin and ensuring preservation of the OTC regulatory compliance dates.

SCE is not requesting approval of this plan in Track 4. Instead, SCE intends to submit any proposed contingent GFG contracts to the Commission for approval, if SCE determines they are cost effective and beneficial, in the third quarter of 2014.[207]

IEP argues that the concept of contingent development contracts could be a practical and cost-effective way to insure against future reliability problems while buying time to see how uncertainties about demand and supply are

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205 Exhibit SCE-1, at 59; RT 1960.

206 Exhibit SCE-1, at 58.

207 RT 1962, 1966, 1982, 1983.

resolved.[208] Vote Solar recognizes there may be some value in SCE's request for permission to enter into gas-fired generation contingency contracts as backup for resources authorized in Tracks 1 and 4. Vote Solar contends SCE's proposal to sign PPAs with gas-fired generation developers that contain opt-out clauses appear to be more reasonable and simpler to implement than the utilities' contingent site preparation proposals, provided the option payment is not exorbitant.[209]

ORA witness Rogers testified that SCE's options contract proposal is an "approach would expose ratepayers to costly termination payments in the event the contracts prove unnecessary."[210] CEERT similarly contends that SCE's proposal is problematic.[211] Alton Energy argues for rejection of SCE's proposal as an inappropriate use of ratepayer funds, and argues it would distract SCE from their other initiatives such as the Living Pilot and Mesa Loop-In.[212]

WPTF does not oppose the SCE proposal, subject to certain caveats. WPTF opposes the concept of using bilateral negotiations for securing the option contracts proposed by SCE, arguing that bilateral negotiations do not ensure that the least cost option will be identified and selected. Further, WPTF argues that such contracts allows utility to pick "winners and losers" on criteria other than least cost.[213] WPTF advocates that the Commission should make it clear that in

[208] IEP Opening Brief, at 34.

[209] Vote Solar Comments, at 13.

[210] Exhibit ORA-5 (Rogers), at 3, 11.

[211] CEERT Opening Brief, at 41.

[212] Alton Energy Opening Brief, at 3.

[213] WPTF Opening Brief, at 4.

option contracts contingency proposals, SCE should allow existing generators, including OTC unit owners, to offer their sites for redevelopment.[214]

We need not make a determination on the merits of SCE's contingency contract proposal here, as SCE is not seeking any specific approval. We do see potential value in such an approach, because there are many unknowns regarding future supply and demand in the LA Basin; contingency contracts may (if appropriately priced, effectively managed and well-located) reduce/mitigate disruptions and uncertainties in the future.

On the other hand, there are many uncertainties about what SCE may propose, and how such contracts work. There are significant questions that must be answered before we could approve such contracts. Such questions include:

- Would these contingency contracts be in addition to site preparation by SCE in the vicinity of Johanna and Santiago substations, thus potentially leading to costly redundancy?
- What metrics should be used to evaluate the cost-effectiveness of these contracts?
- Should separate RFOs be held to procure contingency contracts? If not, how can it be shown that proposed contracts represent the lowest reasonable rate?
- If SCE waited until the next RFO, might a contingency contract bidder improve its offer?
- How would SCE measure and enforce performance under contingency contracts?
- Would contingency contracts unfairly influence the next RFO? For example, if a contract is terminated after site preparation and permitting have already been completed, it may be more likely that this site will be selected in the next RFO.

214 WPTF Opening Brief, at 7.

- In its testimony, SCE states "Second, the availability of Preferred Resources typically cannot be assured until much closer to the time of resource need. There is no assurance these Preferred Resources will ultimately be available to meet needs related to OTC closures because it is unlikely that customers will commit in 2014 that they will implement EE or DR in 2021." [215] If the preferred resources ultimately come online as expected, how will SCE avoid paying for both preferred resources and the contingency GFG contract, in light of SCE's assumed EE and DR procurement timeline? If SCE does not know if the preferred resources will perform until much closer to the time of delivery, on what grounds would SCE ever terminate a GFG option contract?
- Would contingency contracts, in practical terms, make it much more likely that there would be additional, unnecessary GFG procurement?
- What potential costs (direct, indirect or stranded) will ratepayers be exposed to if these contracts are pursued?

SCE may propose contingency contracts in its upcoming procurement application, expected in late 2014 or in a separate application. SDG&E may also propose similar contracts in its procurement application stemming from this decision or in a separate application. In either case, the utility must provide clear and full answers to the questions above before we will consider approving such contracts.

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[215] Exhibit SCE-1, at 63.

6. Conditions for Procurement

6.1. Procurement Process

SCE recommends combining new LCR all source procurement from Track 4 with its all-source procurement RFO authorized in D.13-02-015. SCE argues this combination will both improve the competitiveness of all source bidding, allow for a more optimal selection of resources, and reduce administrative costs to ratepayers of issuing two separate all source solicitations.

SCE recommends that this solicitation not be limited to any particular resource type or project size. As Exhibit SCE-1 states: "[c]reating carve outs for certain technologies or project sizes shrinks the market for all other potential resources, potentially precluding the opportunity to contract with more cost-effective, better fit resources."[216] SCE contends the use of an all source solicitation for incremental Track 4 procurement authorization with no buckets for certain technologies or project sizes will allow SCE to seek a cost-effective portfolio of resources to meet SCE's LCR need consistent with the Loading Order. SCE plans to use the least-cost/best-fit criteria to choose the most cost-effective portfolio to meet SCE's LCR needs, consistent with the Loading Order.[217]

For procurement authorized in this proceeding, SDG&E requests that the Commission direct it to issue an all-source RFO or to contract bilaterally. SDG&E contends that moving forward on an expedited basis with a bilateral contract to address a portion of LCR need would support the policy goals of the State related to timely retirement of OTC facilities and would promote system

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216 Exhibit SCE-2, at 23.

217 SCE Opening Brief, at 12.

reliability – the sooner new local resources are added to the portfolio, the lower the reliability risk.[218]

SDG&E argues that the public interest is best served by procurement of preferred resources through the relevant dedicated Commission proceedings. SDG&E contends there are important issues that require stakeholders input that are best addressed in the dedicated proceeding, such as establishing rules for counting of such resources to meet overall procurement targets, separate from LCR need, and developing mechanisms for recovery of costs from all benefitting customers.[219] SDG&E's procurement strategy holds 70-120 MW open to be filled with demand response and/or energy storage resources in the Commission proceedings dedicated to each such resource, provided that these resources satisfy requirements established by the ISO for operational characteristics that address local reliability needs.[220]

IEP and others recommend that procurement of local capacity resources should occur primarily through an all-source solicitation, where all resources that can meet the specified requirements can compete on a fair basis. IEP argues that the focus of procurement of capacity needed for local reliability should be the resource's viability and ability to provide the products and services needed to maintain reliability.[221]

ORA recommends directing each utility to submit a procurement plan explaining how it plans to accomplish the procurement of preferred resources,

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[218] SDG&E September 4, 2013 Comments, at 5-6.

[219] SDG&E Opening Brief, at 34.

[220] SDG&E Opening Brief, at 8.

[221] IEP Reply Brief, at 22.

including proposed milestones and evaluation dates, and detailed proposals to back stop the procurement. The plans should explain how the totality of the contracts or programs are cost effective and consistent with the loading order, including a demonstration that each utility has assessed the availability, economics and viability of the preferred resources in meeting LCR need. The plans should demonstrate technological neutrality, so that no resource was prevented from the solicitation process, although SCE and SDG&E may include proposals to solicit preferred resources through different avenues.[222]

CEERT recommends adopting a stakeholder process to permit public input on the development of RFOs for both supply-side (i.e., bulk storage) and preferred resources that permits input from parties on its terms and conditions before approved for the IOUs.[223]

Parties including Sierra Club, ORA and CLECA and Vote Solar share a concern that if the Commission adopts SCE's procurement proposals, only gas-fired resources will win, regardless of SCE's intent to pursue preferred resources solutions.[224] These parties recommend that the Commission, if it authorizes any additional Track 4 LCR procurement, require the utilities to first seek to satisfy that additional need with preferred resources. EDF contends that "[i]n comparison to combustion resources, the siting of [energy efficiency, demand response,] and small and large scale renewable generation is significantly less likely to face time delays and substantial obstacles to

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222 ORA Opening Brief, at 31.

223 CEERT Opening Brief, at 54.

224 Sierra Club Opening Brief, at 26-27; Exhibit ORA-2, at 1; CLECA Opening Brief, at 10-11; Vote Solar Reply Brief, at 3.

implementation."[225] EnerNOC indicates such delays would include "attaining GHG emissions reductions required by Assembly Bill (AB) 32."[226]

We have already determined both in D.13-02-015 and in this decision that authorized procurement should be a combination of gas-fired generation and preferred resources, with ranges of procurement for different resource types. Any all-source RFO (and all other procurement methods) must be consistent with the resource ranges authorized in this decision. As discussed herein, compared to D.13-02-015 for SCE, we do not increase the minimum levels of procurement of gas-fired generation and do increase the minimum levels of procurement of preferred resources.

D.13-02-015 at 3 - 4 noted that that decision was a first step in a longer procurement process related to the retirement of OTC plants and other factors: "We consider today's decision a measured first step in a longer process. If as much or more of the preferred resources we expect do materialize, there will be no need for further LCR procurement based on current assumptions. If circumstances change, there may be a need for further LCR procurement in the next long-term procurement proceeding."

There is a need for expeditious action to procure further resources in response to the retirement of SONGS. It will be approximately 18 months form the date for the Track 1 decision to the time SCE files an application for approval of Track 1-authorized procurement. We cannot wait another 18 months or more beyond the date of this decision for consideration of Track 4-authorized procurement. To ORA's point, SCE has already shown how it will procure

[225] EDF Opening Brief, at 7.

[226] EnerNOC Opening Brief, at 8-9.

preferred (and other) resources in a detailed plan, which has already been reviewed and approved by the Energy Division. As SCE has already completed its Track 1 RFO solicitation process, the most efficient and timely method toward approval of new resources in SCE's territory is to use the results of the Track 1 RFO for resources authorized in this decision as well as D.13-02-015. SCE may also propose for approval bilateral contracts for Track 4, consistent with the authority granted in Track 1.

Ordering Paragraph 1 of the track 1 decision, D.13-02-015, states in part: "Southern California Edison Company shall procure between 1,400 and 1,800 MW of electrical capacity in the West Los Angeles sub-area of the Los Angeles basin local reliability area to meet long-term local capacity requirements by 2021." This track 4 decision concerns the SONGS service territory, which for SCE consists of the entire LA Basin. At the same time, we build upon the track 1 decision and recognize that the resource need identified in that decision continues to exist. Thus, SCE should prioritize procurement in the West Los Angeles sub-area of the LA basin. To the extent that SCE wishes to procure resources in the LA Basin, but not in the West LA sub-area, to meet the incremental authorizations in this decision (i.e., for resources beyond those authorized in D.13-02-015), SCE shall amend its approved procurement plan from Track 1 within 90 days of this decision, subject to Energy Division approval.

SCE shall file an application including procurement authorized in Tracks 1 and 4 in 2014, consistent with its Energy Division-authorized procurement plan from Track 1 (and any approved amendment). This application shall include all procurement contracts stemming from Tracks 1 and 4 for which SCE seeks approval at this time, whether from its RFO or bilateral contracts. The exception is any procurement covered by Ordering Paragraph 8 of D.13-02-015, which states: "Southern California Edison Company may provide the conventional gas-fired resources portion of the procurement plan for review ahead of its full procurement plan. If Energy Division approves this portion of the plan Southern California Edison Company may go forward with that procurement." SCE may include any proposed contingency contracts in its application.

For SDG&E, we also will require an all-source RFO as part of its Track 4 solicitation process, in addition to allowing bilateral contracts. The RFO shall meet the same requirements as for SCE in Ordering Paragraph 4 of D.13-02-015. We will require SDG&E to show that it has a specific plan to procure at least the minimum level of resources authorized by this decision, consistent with this decision's requirements for specific resource categories. We agree with parties' comments that all resources that can meet the specified requirements should be able to compete on a fair basis. An RFO is an effective method to accomplish this goal.[227] While SDG&E witness Anderson contends that the potential for double-counting and cannibalization of existing programs arises when procurement of preferred resources occurs along two parallel paths,[228] we find it better to compare resources procured for the same purpose (meeting LCR needs) in the same process (an RFO). SDG&E maintains the responsibility to ensure that its LTPP procurement process is consistent with other Commission requirements. Therefore, SDG&E's RFO shall provide for at least the 200 MW minimum preferred resources/energy storage components.

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[227] We are aware that SCE's Track 1 RFO received a robust response from potential suppliers of various types of resources.

[228] RT 1812 – 1813.

To this end, and consistent with the process ordered for SCE in Track 1, SDG&E shall first submit a procurement plan to be reviewed and approved by Energy Division. The SDG&E procurement plan shall meet the procurement plan requirements as required for SCE in D.13-02-015, and be consistent with this decision. The SDG&E procurement plan shall be provided to Energy Division for review no later than 90 days after the effective date of this decision. Consistent with an approved procurement plan, SDG&E shall file an application for all procurement contracts stemming from Track 4 for which SDG&E seeks approval at that time, whether from an all-source RFO or bilateral contracts. As with SCE, SDG&E may propose in its procurement plan a separate, earlier application for gas-fired generation due to long lead times. SDG&E should include any proposed contingency contracts in its application.

Procurement authorized by this decision should begin as soon as possible. Procurement needs may become critical as early as 2018, and certainly by 2020. To the extent authorized, SCE and SDG&E must expeditiously pursue procurement of any gas-fired generation expected to take several years to develop. Other procurement activities may not need as much lead-time to develop. However, the utilities should not wait until very close to when the need is critical to acquire such resources; to the extent that additional preferred resources or energy storage is cost-effective and well suited to meet LCR needs in the subject geographical areas, SCE and SDG&E should work to procure these resources in advance.

6.2. Solicitation Requirements

Ordering Paragraph 4 of D.13-02-015 required SCE to include the following elements in a Track 1 RFO:

Any Requests for Offers (RFO) issued by Southern California Edison Company pursuant to this Order shall include the following elements, in addition to any RFO requirements not delineated herein but specified by previous Commission procurement decisions (including Decision 07-12-052) and the authorization and requirements of this decision:

a. The resource must meet the identified reliability constraint identified by the California Independent System Operator (ISO);

b. The resource must be demonstrably incremental to the assumptions used in the California ISO studies, to ensure that a given resource is not double counted;

c. The consideration of costs and benefits must be adjusted by their relative effectiveness factor at meeting the California ISO identified constraint;

d. A requirement that resources offer the performance characteristics needed to be eligible to count as local Resource Adequacy capacity;

e. No provisions specifically or implicitly excluding any resource from the bidding process due to resource type (except as authorized in this Order);

f. No provision limiting bids to any specific contract length;

g. Provisions designed to be consistent with the Loading Order approved by the Commission in the Energy Action Plan and to pursue all cost-effective preferred resources in meeting local capacity needs;

h. Provisions designed to minimize costs to ratepayers by procuring the most cost-effective resources consistent with a least cost/best fit analysis;

i. A reasonable method designed to procure local capacity requirement amounts at or within the levels authorized or required in this decision, not counting amounts procured through cost-of-service contracts;

j. An assessment of projected greenhouse gas emissions as part of the cost/benefit analysis;

k. A method to consider flexibility of resources without a requirement that only flexibility of resources be considered; and

l. Use of the most up-to-date effectiveness ratings.

As SCE is authorized to use the results of its Track 1 RFO to procure resources for Track 4 as well, the requirements of Ordering Paragraph 4 of D.13-02-015 continue to hold. To the extent that SCE institutes future RFOs for these purposes, these requirements will apply. SCE should include any proposed contingency contracts in its application. In addition, we will apply the same requirements to SDG&E for any RFO it issues for Track 4 procurement.

7. 2013/2014 TPP Update

Some parties urge the Commission to revise any interim procurement authorization for incremental need in the SONGS study area once the 2013/2014 TPP results are available. For example, ORA contends that revising the need (upwards or downwards) based on more accurate information, would allow LCR procurement based on the facts that are more likely to reflect that need that will exist in 2022.[229] A number of other parties echo this sentiment.[230]

As discussed herein, it is necessary to authorize procurement at this time to replace capacity lost by the untimely retirement of SONGS. The authorization approved today does not assume any specific transmission upgrades or new

[229] ORA Opening Brief, at 8.

[230] *See*, for example, CEERT Opening Brief, at 20: "it is CEERT's position that inclusion of the 'additional evidence' of the TPP results will create a better record than at present to determine both LCR needs without SONGS and the best means (in particular, preferred resources) to reduce or meet that need without jeopardizing timeliness."

projects which might be determined in the 2013/2014 TPP. At the same time, we do not authorize procurement of all resources identified by the ISO as needed to meet LCR needs in the SONGS service area by 2022. As discussed at length herein, we determine that some combination of already-authorized procurement, additional expected preferred resources, and new transmission projects will significantly reduce the need identified by the ISO.

If, at one extreme, no new transmission resources are identified in the 2013/2014 TPP which would reduce LCR needs in the SONGS service area by 2022, the procurement authorized today may need to be supplemented. We anticipate this would occur through some combination of: a) procurement at or near the maximum levels authorized in this decision; b) procurement of additional preferred resources (beyond the assumptions used by ISO in Track 4 models) as anticipated in this decision; c) additional procurement authorized in future LTPP proceedings; and d) potential delay in retirements of OTC plants. In other words, because we assume no new transmission projects in our analysis, a similar outcome from the 2013/2104 TPP does not require any change or update to this decision.

If some level of new transmission resources is identified in the 2013/2014 TPP which would reduce LCR needs in the SONGS service area by 2022 (for example, the Mesa Loop-In project), the total amount of overall procurement needed in the SONGS service area would be reduced. However, we have already considered the possibility of the Mesa Loop-In going forward in analyzing procurement authorizations. Nevertheless, it is possible that the 2103/2014 TPP results would mean that fewer of the resources identified in this subsection ultimately would be needed. However, this does not mean there would be a need to change or update this decision. Instead, some combination of the following would occur: a) procurement at or near the minimum levels authorized in this decision; b) less procurement or no procurement authorized in future LTPP proceedings; and c) less of a need to delay retirements of OTC plants.

The range of procurement authorized for both utilities in this decision is intended to provide flexibility to meet a variety of circumstances. The 2013/2104 TPP is unlikely to result in major changes to the analysis in this decision. Therefore, we will close Track 4 of this proceeding with this decision.

8. Cost Allocation Mechanism

The Cost Allocation Mechanism, or CAM, is designed to ensure that the costs of new resources procured to ensure local or system reliability are shared equally among all utility distribution customers, regardless of their generation provider. CAM is based on the principle that reliability is a collective good and that the customers of Electrical Service Providers (ESPs) and Community Choice Aggregators (CCAs) will also benefit from investments in system reliability made by regulated utilities. The current CAM achieves this goal by subtracting the energy value of new generation out from long-term contracts for new generation and sharing the residual capacity costs equally among all bundled and un-bundled customers within the utility service-area.

SCE[231] and SDGE[232] both argue that all Track 4 procurement should receive CAM treatment. SCE argues that the issue of CAM treatment was already litigated in Ordering Paragraph 21 of D.13-02-015 and therefore should not be re-litigated. SCE argues that Track 4 is intended to maintain local reliability and

231 Exhibit SCE-1, at 59-60.

232 Exhibit SDG&E-1 (Anderson), at 12.

therefore, according to Pub. Util. Code § 365.1(2)(B) all procurement coming out of Track 4 is CAM-eligible.

AReM/DACC[233] disputes both of these arguments. First, AReM/DACC suggests that since SONGS replacement was not discussed in Track I any determination of CAM applicability to Track I procurement should not automatically apply for Track 4 procurement as well.[234] AReM/DACC argues that as a general principle, CAMs should be applied with circumspection and the utilities need to justify CAM treatment on a case-by-case basis. For Track 4 procurement, they argue that procurement is to meet the bundled load of SDG&E and SCE customers, as opposed to general local or system reliability needs. Therefore, only utility bundled customers should pay SONGS replacement costs.

In reply briefs, PG&E, SCE, SDG&E and TURN argue that Track 4 procurement is for local reliability and not to meet bundled load, and therefore should be subjected to CAM. These parties argue that any resources the Commission asks the utilities to make to meet local reliability criteria in the SONGS service area will benefit both bundled and unbundled customers.

TURN[235] argues that local reliability needs – including those driven by expected resource retirements – are not solely the responsibility of bundled customers, even when they may be driven in part by the retirement of a resource that served bundled customer needs, such as SONGS. Further, all of the utilities' customers will benefit equally from the resources that may be procured pursuant

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[233] Exhibit AReM/DACC-1, at 2-17.

[234] See also Exhibit WPTF-1, at 13.

[235] TURN Reply Brief, at 2-3.

to Track 4 authorization, so all customers should share equally in paying for such resources. Finally, SCE and SDG&E have already met, are continuing to meet and will continue meeting – to the extent the Commission requires and allows – their bundled customers' additional capacity and energy needs arising from the retirement of SONGS. TURN also argue that the utilities are meeting bundled customers' needs at bundled customers' expense, and have no other obligation to make long-term investments in resources to meet local reliability needs other than as directed by the Commission in a docket such as this Long-Term Procurement Plan.

Section 365.1(c)(2)(A)-(B) holds that in instances when the Commission determines that new generation is needed to meet local or system area reliability needs for the benefit of all customers in the IOU's service area, the net capacity costs for the new capacity shall be allocated in a fair and equitable manner to all benefiting customers, including DA, CCA and bundled load. Simply put, each customer must pay their fair share for the benefits that flow to them from new generation for reliability purposes for the full life of the asset.

D.13-02-015, Conclusion of Law 21 states:

> "The cost allocation mechanism established in D.06-07-029 and refined in D.07-09-04, D.08-09-012 and D.11-05-005 remains reasonable for application in this proceeding without modification, and is fair and equitable as required by Section 365.1(c)(2)(A)-(B)."

Ordering Paragraph 15 of D.13-02-015 states:

> "Southern California Edison Company shall allocate costs incurred as a result of procurement authorized in this decision and approved by the Commission consistent with the cost allocation mechanism approved in Decisions (D.) 06-07-029, D.07-09-044, D.08-09-012 and D.11-05-005."

The basic question related to CAM in this decision is whether procurement authorized in this decision should be treated any differently from procurement authorized in D.13-02-015. There is no significant difference between procurement authorized in this decision and procurement authorized in D.13-02-015. In both cases, procurement is pursuant to local reliability determinations starting with ISO studies for this purpose, as modified by our analysis. We find that the procurement authorized in this decision is for the purpose of ensuring local reliability in the SONGS service area, for the benefit of all utility distribution customers in that area. We conclude that such procurement meets the criteria of Section 365.1(c)(2)(A)-(B). Therefore, SCE and SDG&E shall allocate costs incurred as a result of procurement authorized in this decision, and approved by the Commission. In most cases we expect this allocation to be consistent with D.13-02-015 and the CAM adopted in D.06-07-029, D.07-09-044, D.08-09-012 and D.11-05-005, but there may be resources where an existing alternative method of allocating resources costs may be preferred; for example, cost may be recoverable through the Energy Program Investment Charge. As SCE states in its Reply Comments on the Proposed Decision at 3, it will "propose an RA allocation method in its application for approval of the results of its LCR RFO when those results are fully understood." We will require that, in applications for contract approval, the IOU shall recommend a method of cost allocation appropriate for the resource being procured.

SCE has proposed that some of its procurement for Track 4 could involve contingency or option contracts for GFG, giving SCE the right to terminate the contracts should sufficient renewables or transmission solutions obviate the need.[236] SCE argues that while such contracts are not covered by current CAM rules, the CAM framework could be expanded to cover such option contracts.

AReM/DACC[237] argues that these contracts cannot be subjected to CAM because there is no way to calculate net capacity costs by accounting for revenues from generation or related products. Since this calculation is required by statute (Section 365.1(c)(2)(C)), SCE should not be allowed to use CAM for these option contracts.

TURN[238] argues that it is not possible to make a determination regarding CAM or some similar cost-sharing mechanism for contingent generation contracts until the utilities have filed for approval of such programs. Therefore, there is no need to address the CAM issue for SCE's proposed contingent gas-fired generation contracts at this time.

Contingency or options contracts raise issues concerning cost allocation that have not been contemplated by the Commission to date. SCE does not have a specific proposal for contingency or options contracts before us at this time. SCE and/or SDG&E may propose such contracts in their future procurement applications stemming from this decision. We do not make any determination about whether contingency or options contracts will be eligible for CAM. If and when SSCE and/or SDG&E propose such contracts, they should propose whether certain costs should be allocated through CAM, and, if so determined, propose a methodology for allocation.

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236 Exhibit SCE-1, at 58.

237 Exhibit AReM/DACC-1, at 5.

238 TURN Opening Brief, at 20-21.

9. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on March 3, 2014, and reply comments were filed on March 10, 2014.

The following changes were made by the Administrative Law Judge based on comments:

1. Increase SDG&E maximum procurement authorization from 700 MW to 800 MW (based on comments from SDG&E, IEP and NRG);
2. Allow SCE to submit an amended procurement plan, if SCE wishes to procure in the LA Basin, but outside of the West LA sub-area as required in D.13-02-015 (based on comments from CEERT);
3. Modify Attachment B to require SDG&E to explain it its procurement plan how it will ensure that energy efficiency and demand response resources procured to meet its LCR needs are incremental to resources that would otherwise develop or be procured in other programs (based on comments from ORA);
4. Add an additional question regarding potential contingency contracts (based on comments from ORA);
5. Modifications to discussion of City of Redondo Beach testimony (based on comments from City of Redondo Beach);
6. Editing of Ordering Paragraph 1(e) to clarify requirements for energy storage procurement (based on comments from SCE);

7. Modify Ordering Paragraph 3 to allow bilateral contracts which are not cost-of-service contracts (based on comments of SDG&E);
8. Editing of Finding of Fact 45 regarding ISO modeling of demand response resources (based on comments from EnerNOC);
9. Clarification that the CAM may not be the only Commission-authorized cost allocation method which may be appropriate for certain resources (based on comments of SCE).

Other minor edits and clarifications to the Proposed Decision were made throughout the decision.

10. Assignment of Proceeding

The assigned Commissioner is Michel Peter Florio and the assigned ALJ is David M. Gamson. ALJ Gamson is the Presiding Officer. This proceeding is categorized as ratesetting.

Findings of Fact

1. The Track 1 decision in this docket, D.13-02-015, authorized SCE to procure between 1,400 and 1,800 MW of electrical capacity in the West Los Angeles sub-area of the LA Basin local reliability area to meet long-term local capacity requirements by 2021.

2. The San Onofre Nuclear Generation Station, Units 2 and 3 (SONGS) permanently closed in June 2013.

3. The SONGS study area consists of all of the territory of SDG&E, and the LA Basin portion of SCE's territory.

4. Until 2011, SONGS had supplied 2,246 MW of greenhouse gas -free base load power to the LA Basin and San Diego and played an important role in system stability in the San Diego Local Area.

5. Both SCE and SDG&E have sufficient supplies to meet projected demands in the SONGS service area through at least 2018, even with the unexpected early retirement of SONGS.

6. Starting in 2015, around 4,900 MW of OTC plants in the local transmission-constrained areas of the LA Basin local area may retire over the next several years, as well as other OTC plants in the San Diego local areas, because of State Water Resources Control Board regulations.

7. The ISO modeled retirement of OTC plants in the SONGS study area, along with the retirement of SONGS, to produce an analysis of need for the area.

8. The ISO based its long-term LCR study on a 1-in-10 year annual peak load and a Category C Contingency.

9. On May 21, 2013, Attachment A of the revised Scoping Memo for this proceeding set forth a series of assumptions for the ISO to use in modeling long-term capacity needs in the absence of SONGS.

10. The revised Scoping Ruling established a 1-in-10 year versus 1-in-2 year peak weather forecast for transmission and local area planning.

11. The ISO performed its SONGS Study area LCR study consistent with the assumptions in the revised Scoping Memo.

12. The ISO calculates that between 2,399 MW and 2,534 MW (depending on the allocation between SCE and SDG&E) will be needed in the SONGS study area by 2022.

13. Other parties performed power flow models. While these studies were useful for analytical purposes, they did not conform to the revised Scoping Memo.

14. SCE and SDG&E study results show projected residual long-term local capacity needs ranging from 2,302 – 2,534 MW based on slightly different

assumptions and methodologies from those used by the ISO per the revised Scoping Memo.

15. It is very likely or near certain that 1,800 MW authorized by the D.13-02-015 will be procured by SCE.

16. It is certain that 300 MW authorized D.13-03-029 will be procured by SDG&E, due to the approval given in D.14-02-016.

17. The June 28, 2013 Motion of ORA, CEJA and Sierra Club was not ruled upon before the proceeding was submitted.

18. The revised Scoping Memo did not include any specific amount of reactive power as an assumption for the ISO to model.

19. The record in the proceeding shows that there are sufficient resources to provide VAR support in the SONGS study area without further action at this time.

20. Because there is not sufficient information available from the record to determine if additional reactive power resources not modeled by the ISO could be available to reduce LCR needs, any analysis of whether or how much additional reactive power support would change LCR needs in the SONGS service area is speculative.

21. Consistent with Western Electricity Coordinating Council and North American Reliability Corporation guidelines, the ISO has approved Special Protection Systems (SPS), also known as a Special Protection Schemes, on several occasions in California.

22. An SPS allows the use of load shedding as an interim measure when there are insufficient resources to meet more stringent guidelines.

23. The ISO has the authority within WECC/NERC guidelines to implement or continue a SPS in the SDG&E territory.

24. The most important contingencies identified by the ISO in the SDG&E territory have a likelihood of an N-1-1 failure between every 21 and 928 years.

25. In the unlikely event that an N-1-1 failure would occur in the planning period of this proceeding during summer hours, it will not lead to load shedding except for less than 2.5% of the time.

26. There would need to be a minimum of 588 MW fewer resources if there is a temporary SPS in place, as compared to the resources needed to support the N-1-1 contingency identified by the ISO in the SDG&E territory.

27. The cost to ratepayers of additional resources to mitigate the N-1-1 contingency identified by the ISO in the SDG&E territory would be at least $595 million; there is evidence that such investment may not be cost-effective.

28. The cost to affected customers of a load shedding event under an SPS approach is estimated at under $250 million per event, and must be weighted by the low probability of the occurrence of load shedding.

29. It is likely that the procurement of preferred resources and/or transmission solutions will develop sufficiently over time to mitigate the need for further resources, so that the SPS in the SDG&E territory can be lifted and reliability at an N-1-1 contingency level can be maintained.

30. Exogenous modifications (including assumptions regarding load-shedding) do not affect the ISO modeling directly, but inform our judgment regarding appropriate procurement levels.

31. Changing a Category C contingency to a Category D contingency would directly change the ISO model output.

32. 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.

33. There is no credible basis upon which to find that the ISO's analysis, that the limiting contingency for the SONGS study area is the N-1-1 Category C3 SWPL/Sunrise overlapping outage assumed and modeled by the ISO, is flawed.

34. SCE and SDG&E propose potential transmission solutions to part of the LCR need in the SONGS study area.

35. The Mesa Loop-In project involves rebuilding and upgrading the existing Mesa 230 kV substation in the LA Basin to 500 KV and looping the Vincent – Mira Loma 500 kV line and two 230 kV lines into the substation.

36. The Mesa Loop-In project would reduce the amount of gas-fired generation that would need to be sited in the LA Basin by approximately 1,200 MW, or 734 MW if there is no load shedding or additional gas-fired generation in the SDG&E territory.

37. The Mesa Loop-In project was submitted to the ISO as part of its 2013-2014 Transmission Planning Process.

38. There is no record to determine if the Mesa Loop-In will be approved by the ISO in its TPP, or to determine whether, even if approved, it would be in service before 2022.

39. The Mesa Loop-In proposal is a promising and reasonably likely alternative to other new resources in the LA Basin, if it is approved by the ISO and if it would be in service before 2022.

40. SDG&E's proposed 500 kV Direct Current transmission project from Imperial Valley to SONGS would reduce the San Diego generation requirement by 850 MW and would reduce the generation requirement for the LA Basin by 551 MW.

41. SDG&E's proposed 500 kV regional transmission project from Devers Substation to a new 230 kV substation in north San Diego County would

reduce the LCR need for San Diego by 550 MW and reduce the LCR need for the LA Basin by 400 MW.

42. SDG&E submitted two 500 kV transmission options with different routing options from Imperial Valley to North County to the ISO's 2013-2014 Transmission Planning Process.

43. There is substantial uncertainty as to how quickly SDG&E's proposed transmission projects could be licensed and built.

44. There is a reasonable possibility that at least one of the transmission solutions examined by SCE and SDG&E will be operational by 2022. The least complex of these projects is the Mesa-Loop-In project, which is therefore the most likely to meet this timeframe.

45. Consistent with the revised Scoping Memo, the ISO determined that demand response resources which cannot respond in 30 minutes should be considered 'second contingency' resources.

46. Consistent with the revised Scoping Memo, 997 MW of 'second contingency' demand response in the ISO modeling was not available to avoid the second contingency, but would be available to respond to the second contingency.

47. It is reasonable to expect that, in the future, some amount of what is now considered 'second contingency' demand response resources can be available to mitigate the first contingency, and therefore meet LCR needs.

48. D.13-10-040 sets energy storage targets of 580 MW for SCE and 165 MW for SDG&E, to be procured gradually through biennial solicitations from 2014 through 2020 and to be online no later than December 31, 2024.

49. The energy storage targets adopted in D.13-10-040 cannot be assumed to count toward meeting the LCR need on a megawatt-for-megawatt basis.

Potential amounts of demand response, energy efficiency or solar PV resources also cannot be assumed to count toward meeting the LCR need on a megawatt-for-megawatt basis.

50. It is likely that some of the energy storage targets will available and effective to meet LCR needs in the SONGS service area before 2022.

51. 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.

52. The revised Scoping Memo erroneously used the low-level uncommitted energy efficiency estimate instead of the mid-level uncommitted energy efficiency level, because the latter is consistent with the fact that SDG&E's territory is co-existent with its part of the SONGS service territory.

53. LCR study data from SDG&E shows the LCR difference is 152 MW for the more appropriate mid-level energy efficiency estimate.

54. Consistent with the revised Scoping Memo, the ISO correctly designates incremental customer-side solar PV as a 'second contingency' resource because it is difficult to predict the location where customer-side PV will get built.

55. It is likely that Commission programs and the marketplace will increase the amount of solar PV in the future. However, there is no specific data or analysis in the record to determine where solar PV will locate, or the impacts of solar PV on LCR needs.

56. SCE's Living Pilot is a promising concept.

57. The Living Pilot is not being proposed by SCE at this time, therefore it is not possible now to make any determination about its viability or ability to meet LCR needs in the LA Basin.

58. D.13-02-015, Finding of Fact 7, continues to be valid: "Both under-procurement and over-procurement entail significant risks. Under-procurement entails risks of reliability problems and the impacts of mitigating such problems in a short timeframe. Over-procurement entails risks of excessive costs and unnecessary environmental degradation. It is not possible to quantify whether the risks of over- or under-procurement are greater."

59. D.13-02-015, Finding of Fact 32 continues to be valid: "A maximum LCR procurement level will protect ratepayers from excessive costs resulting from potential over-procurement."

60. PG&E does not adequately take into account the likelihood of various supply or demand considerations which are either very likely or reasonably likely to occur, and which will lower the overall LCR need from the levels modeled by the ISO.

61. Redondo Beach's study does not use many of the same analytical methods as the ISO.

62. The highest reasonable LCR need level must take into account those resources which are very likely to be procured in the time frame between now and 2022.

63. Taking very likely or certain modifications into account, the highest prudent level of procurement authorization for the SONGS study area would be 1,802 MW (rounded to 1,800 MW).

64. At least some resources beyond those counted to determine the 1,800 MW maximum procurement level are reasonably likely to be procured in the SONGS study area by 2022.

65. The total of all reasonably possible resources or assumptions identified by parties that were not studied by the ISO equals approximately 4,600 MW.

66. It is reasonable to assume that at least between 10% and 20% of the approximately 4600 MW of resources not studied by the ISO will be available.

67. Using a methodology of subtracting out any one of several possible resources or assumptions not included in the ISO modeling produces a range of maximum procurement levels which takes into account between 588 and 997 MW, or between 13% and 22% of the 4,600 MW in total not studied by the ISO.

68. A maximum prudent procurement analysis which incorporate one of the likely resources or assumptions to meet or reduce LCR needs shows the upper bound of a reasonable procurement range under different assumptions ranges from 1,800 MW down to 1,393 MW.

69. While it is reasonable to assume that some resources not accounted for in the calculation of maximum need will be available and will mitigate LCR needs, it is not reasonable to assume this will be true for most of these resources.

70. While it is mathematically possible to construct an analysis using a series of optimistic assumptions about resource availability that could lead to a finding of zero or negative need, we find that a conclusion of zero need is not reasonable.

71. A proxy for calculating a minimum LCR need level is to calculate the LCR impact if any two likely potential scenarios (load-shedding, Mesa Loop-In, additional energy efficiency impacts, 'second contingency' demand response, energy storage, 'second contingency' solar PV) should occur.

72. Using a methodology of subtracting out any two of several possible resources or assumptions not included in the ISO modeling produces a range of minimum procurement levels which takes into account between 1,322 and 1,797 MW, or between 29% and 39% of 4,600 MW.

73. In each case of 100% availability of any two likely scenarios not included in the ISO's modeling, a minimum procurement level ranges from 593 to 1,067 MW (not taking into account uncertainties of effectiveness of various resources in meeting or reducing LCR needs).

74. Parties' recommendations (other than those recommending zero procurement or over-procurement) have in common certain subtractions from a total LCR need for procurement already authorized and calculations of expected resources. These parties' recommendations range from approximately 800 MW to 1,500 MW for the SONGS service area.

75. An overall authorized procurement level for the SONGS service area at this time of 1,000 -1,500 MW is consistent with the recommendations of many parties and is near the center of the overall zone of reasonableness.

76. Authorized procurement levels of 1,000 to 1,500 MW will not provide the full amount needed to meet the LCR needs in the SONGS service territory through 2022; a significant amount of future resources to meet LCR needs in the SONGS service territory will come from procurement authorized in other Commission proceedings, the marketplace and other regulatory forums.

77. Between 67% and 80% of procurement needed to address LCR needs in the SONGS service area by 2022 must be in the LA Basin, which is in SCE territory. The remainder would be in the SDG&E service territory.

78. It is not possible at this time to discern how resources ultimately will be distributed between SCE and SDG&E territories.

79. Between D.13-02-015 and D.13-03-029/D.14-02-016, over 85% of authorized resources are already slated for SCE territory.

80. Authorizing a similar procurement range for SCE and SDG&E, with a 100 MW higher maximum for SDG&E, should be consistent with the requirement that 67 -80% total procurement needs to be in the SCE territory.

81. Authorizing SCE to procure between 500 and 700 MW in its portion of the SONGS service area is within the range of prudent procurement. Authorizing SDG&E to procure between 500 and 800 MW in its portion of the SONGS service area is within the range of prudent procurement.

82. D.13-02-015, Finding of Fact 30 continues to be valid: "It is necessary that a significant amount of this procurement level be met through conventional gas-fired resources in order to ensure LCR needs will be met."

83. Pursuing procurement of preferred resources consistent with the Loading Order must be balanced by ensuring that grid operations are not potentially compromised by excessive reliance on intermittent resources and resources with uncertain ability to meet LCR needs.

84. It is not necessary to require any specific incremental procurement for SCE from gas-fired resources, beyond that specified in D.13-02-015. However, expanding the range of potential gas-fired procurement from 1,000 – 1,200 MW (per D.13-02-015) to 1,000 – 1,500 MW provides greater flexibility to SCE to meet reliability needs.

85. SCE's procurement proposal would expand the range of potential procurement of preferred resources and energy storage, but would allow SCE to procure up to 89% of authorized Track 1 and Track 4 resources from gas-fired generation.

86. Requiring SCE to procure at least 400 MW additional procurement from preferred resources or energy storage, beyond the amount required by

D.13-02-015, increases the percentage of procurement from these resources to 21% to 60%, which is above the 14% to 44% range authorized in D.13-02-015.

87. Requiring SDG&E to procure from at least 200 MW of additional resources authorized by this decision from preferred resources and/or energy storage would result in 22%to 78% of additional resources from preferred resources and/or energy storage, after consideration of procurement authorized by D.13-03-029 and approved by the Commission in D.14-02-016.

88. Because the process for utility solicitations of energy storage per D.13-10-040 has not yet started, it is too early to know if such targets are too high, too low or just right.

89. It will be approximately 18 months form the date for the Track 1 decision to the time SCE files an application for approval of Track 1-authorized procurement. It would likely be another 18 months or more beyond the date of this decision for consideration of Track 4-authorized procurement, unless SCE is allowed to combine Track 4 procurement with its Track 1 procurement process.

90. SDG&E can potentially procure the required amount of preferred and other resources needed to meet the LCR need in its portion of the SONGS service area through an all-source RFO and bilateral contracts.

91. Procurement needs may become critical as early as 2018, and certainly by 2020.

92. The procurement authorized in this decision is for the purpose of ensuring local reliability in the SONGS service area, for the benefit of all utility distribution customers in that area.

93. The resource need identified in D.13-02-015 continues to exist in the West Los Angeles sub-area of the LA Basin. Resources in other portions of the LA Basin may also meet incremental LCR needs identified in this decision.

Conclusions of Law

1. While a primary responsibility of the Commission is to ensure safety and reliability in the electrical system under § 380(c), § 330(g), § 330(h), § 362(a), and § 334, that responsibility must be balanced with other statutory and policy considerations. Specifically, the Commission has a statutory duty to ensure that customers receive reasonable services at just and reasonable rates per § 451 and § 454, and to protect the environment under Pub. Util. Code sections including § 399.11 (Renewables Portfolio Standard) and § 454.5(b)(9)(C) (Loading Order).

2. The ISO has statutory responsibility for the efficient use and reliable operation of the transmission grid under § 345 and shall "ensure the reliability of electric service and the health and safety of the public" under § 345.5(b).

3. The Loading Order, first set forth in the Commission's 2003 Energy Action Plan, and presented in the Energy Action Plan II adopted by this Commission and the CEC in October 2005, established that the state, in meeting its energy needs, would invest first in energy efficiency and demand-side resources, followed by renewable resources, and only then in clean conventional electricity supply.

4. It is reasonable for the Commission to use LCR forecasts modeled by the ISO using assumptions pursuant to the revised Scoping Memo as the starting point for analyzing long-term LCR requirements in the SONGS study area.

5. The ISO study adjustment of forecasted LCR need for 1,800 MW from D.13-02-015 for the SONGS study area is reasonable and should be included in determining how much local capacity to procure for the SONGS study area.

6. The ISO study adjustment of forecasted LCR need for 300 MW from D.13-03-029 for the SONGS study area is reasonable and should be included in determining how much local capacity to procure for the SONGS study area.

7. The June 28, 2013 Motion of ORA, CEJA and Sierra Club should be denied as moot.

8. The ISO study of LCR needs for the SONGS service area should not be adjusted to account for speculative amounts of additional reactive power support.

9. Load shedding through an SPS instituted or continued by the ISO should only be used judiciously as mitigation for contingencies.

10. It is not reasonable to authorize procurement of additional resources at this time to mitigate load-shedding for the N-1-1 contingency identified by the ISO in the SDG&E territory.

11. It is prudent to wait to see what resources develop in the SONGS service area to determine if an SPS or other load-shedding protocol can serve as a bridge until such resources are in place.

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.

13. In decisions including D.13-06-024, D.13-02-015, and D.13-03-029, the Commission has deferred to the ISO regarding power flow modeling.

14. It is reasonable to use the ISO power flow models as the basis for this decision, with certain exogenous modifications.

15. There is not enough information available at this time to make a specific finding that SCE or SDG&E's proposed transmission projects will be able to reduce the LCR need in the SONGS service territory by 2022.

16. Due to significant uncertainties, the ISO's forecast should not be adjusted at this time to assume LCR benefits from the SCE Mesa Loop-In project or SDG&E's proposed transmission projects.

17. Potential transmission solutions provide more confidence that it is not necessary at this time to authorize the utilities to procure all of the resources indicated to be necessary in the ISO's study.

18. The ISO's forecast should not be adjusted to assume 'second contingency' demand response resources will be available to meet LCR needs.

19. The likelihood that some demand response resources, currently considered 'second contingency' resources, will be available to meet LCR needs in the future provides more confidence that it is not necessary at this time to authorize the utilities to procure all of the resources indicated to be necessary in the ISO's study.

20. While the LCR effect of potential energy storage resources cannot be quantified at this time, the targets and requirements of D.13-10-040 lead to a conclusion that energy storage resources will reduce LCR needs in the SONGS service area to some extent in the future.

21. The potential of energy storage to meet LCR needs provides more confidence that it is not necessary at this time to authorize the utilities to procure all of the resources indicated to be necessary in the ISO's study.

22. The revised Scoping Memo should have used the mid-level uncommitted energy efficiency estimate for SDG&E instead of the low-level estimate.

23. It is reasonable to adjust the ISO study results by 152 MW consistent with the mid-level uncommitted energy efficiency level for SDG&E.

24. It is too speculative to make any changes to the ISO study results to account for solar PV.

25. PG&E's recommended procurement levels carry a significant risk of over-procurement.

26. Any procurement level above 1800 MW entails too high of a possibility of over procurement.

27. It would be prudent to authorize procurement of less than 1,800 MW because other resources are reasonably likely to be procured, even though in some cases their LCR impacts cannot be precisely measured. To do otherwise would most likely lead to over-procurement.

28. For the purpose of calculating a maximum procurement level, it is reasonable to assume that at least 13% - 22% of resources or assumptions not studied by the ISO will ultimately be available to meet or reduce LCR needs in the SONGS service area by 2022.

29. To account for uncertainties about effectiveness of LCR reductions for certain resources, a reasonable maximum procurement level should be somewhere between 1,383 and 1,800 MW.

30. A finding of zero LCR need for the SONGS service area for 2022 would not be prudent because it would most likely lead to under-procurement.

31. Analyzing 100% availability of any two sets of resources or assumptions not included in the ISO models is a reasonable proxy for the largest amount of available LCR reductions from the ISO analysis.

32. For the purpose of calculating a minimum procurement level, it is reasonable to assume that at least 29% to 39% of resources or assumptions not studied by the ISO will ultimately be available to meet or reduce LCR needs in the SONGS service area by 2022.

33. To be certain that authorized procurement levels will not result in under-procurement, the minimum authorized procurement level should in no

case be no less than 593 MW, but could be reasonably set anywhere between 593 and 1,067 MW.

34. Authorizing a procurement range takes into account a) uncertainties about supply and demand conditions; b) the ability to process new information during the procurement process; c) the need to provide the utilities with flexibility to procure resources which may only be available in large increments; d) increases in requirements to procure preferred resources (as discussed below); and e) the need to provide utilities and the Commission with the ability to protect ratepayers by not forcing certain less economic procurement decisions.

35. An overall authorized procurement level for the SONGS service area at this time of 1,000 -1,500 MW provides reasonable ratepayer protection against over procurement and simultaneously provides reasonable protection from reliability impacts from under procurement.

36. It is reasonable to authorize SCE to procure between 500 and 700 MW in its portions of the SONGS service area. It is reasonable to authorize SDG&E to procure between 500 and 800 MW in its portions of the SONGS service area.

37. It is prudent to promote preferred resources to the greatest extent feasible, subject to ensuring a continued high level of reliability.

38. A prudent approach to reliability entails a gradual increase in the level of preferred resources and energy storage into the resource mix.

39. Consistent with D.13-02-015, it is reasonable to provide a level of flexibility to SCE and to ensure procurement consistent with ISO reliability standards by expanding the range of procurement specified in D.13-02-015 for gas-fired resources, preferred resources and energy storage.

40. A similar range of procurement flexibility should be provided to SDG&E as to SCE.

41. SCE's proposal to add its additional Track 4 procurement requirement to its Track 1 authorization from D.13-02-015, without any specification of resource type, is not consistent with Commission policies to adhere to the Loading Order.

42. Requiring SCE to procure between 400 and 1,500 MW (or 21% to 60%) from preferred resources or energy storage in total between D.13-02-015 and this decision is more consistent with the Loading Order than SCE's proposal.

43. SDG&E should be authorized some flexibility to procure gas-fired, preferred and energy storage resources to meet reliability needs.

44. Requiring SDG&E to procure at least 200 MW from preferred resources or energy storage is consistent with the authority granted to SCE herein and consistent with the Loading Order.

45. There is insufficient information to modify the energy storage procurement targets established in D.13-10-040.

46. It is reasonable to allow SCE to use the same procurement process for both Track 1 and Track 4-authorized procurement, consistent with SCE's approved Track 1 procurement plan.

47. SDG&E should be required to show that it has a specific plan to procure the resources authorized by this decision, consistent with the procurement categories and other requirements of this decision.

48. Procurement authorized by this decision should begin as soon as possible.

49. SCE should prioritize procurement in the West Los Angeles sub-area of the LA Basin.

50. The procurement authorized in this decision meets the criteria of Section 365.1(c)(2)(A)-(B) for the purposes of cost allocation.

51. The cost allocation mechanism established in D.06-07-029 and refined in D.07-09-004, D.08-09-012 and D.11-05-005 (and as applied in D.13-02-015)

remains reasonable for application in this proceeding without modification, and is fair and equitable as required by Section 365.1(c)(2)(A)-(B). Other Commission-authorized cost allocation methods may instead be appropriate for certain resources.

52. The November 14, 2013 e-mail Ruling of ALJ Gamson denying a November 4, 2013 Motion for Official Notice of Protect Our Communities should be affirmed because the requested materials do not meet the criteria for Official Notice or Judicial Notice.

53. The SCE Motion to Strike the Opening Brief of the City of Redondo Beach should be denied because the brief addresses record issues related to local reliability.

54. The SCE and SDG&E Joint Motions to Strike the Opening Brief and Reply Brief of Protect Our Communities should be granted because the brief is substantially based on non-record evidence.

55. The SCE, SDG&E and PG&E Motions to Strike the Opening Brief of Marin Energy Authority should be granted because the brief is substantially concerned with matters outside of the scope of the this track of the proceeding.

56. The Southern California Edison Company Motion to Partially Strike the Opening Brief of Nevada Hydro Company is granted because the portions of the brief to be stricken are outside of the scope of this track of the proceeding.

O R D E R

IT IS ORDERED that:

1. In combination with procurement authorizations totaling 1,400 to 1,800 Megawatts (MW) in Ordering Paragraph 1 of Decision 13-02-015, Southern California Edison Company is authorized to procure between 1,900 and

2,500 MW of electrical capacity in the Los Angeles Basin local reliability area to meet long-term local capacity requirements by the end of 2021. Procurement must abide by the following guidelines and table:

a. At least 1,000 MW, but no more than 1,500 MW, of local capacity must be from conventional gas-fired resources, including combined heat and power resources;

b. At least 50 MW of local capacity must be procured from energy storage resources (as defined in Decision 13-10-040);

c. At least 550 MW of local capacity must be procured from preferred resources consistent with the Loading Order of the Energy Action Plan (beyond the requirement of subsection b of this Ordering Paragraph). Bulk energy storage and large pumped hydro facilities shall not be excluded.

d. At least 300 MW, but no more than 500 MW, of local capacity, beyond the minimum amounts specified in subparagraphs (a), (b) and (c), must be procured and can be from any resource able to meet local capacity requirements.

e. Subject to the overall cap of 2500 MW, any additional local capacity, beyond the amounts specified in subparagraphs (a), (b), (c) and (d), may only be procured through preferred resources (including bulk energy storage and large pumped hydro facilities) consistent with the Loading Order of the Energy Action Plan and/or energy storage resources. Such preferred resources shall be in addition to preferred resources already required by the Commission to be procured or obtained through decisions in other relevant proceedings,.

Resource Type	Track 1 LCR Resources (D.13-02-015)	Additional Track 4 Authorization	Total Authorization
Preferred Resources **Minimum Requirement**	150 MW	400 MW	550 MW
Energy Storage **Minimum Requirement**	50 MW		50 MW
Gas-fired Generation (including CHP) **Minimum Requirement**	1,000 MW		1,000 MW
Optional Additional: Only From Preferred Resources /Energy Storage	Up to 400MW		Up to 400 MW
Additional from Any Resource	200 MW	100 to 300 MW	300 to 500 MW
Total Procurement Authorization	**1,400 to 1800 MW**	**500 to 700 MW**	**1,900 to 2,500 MW**

2. San Diego Gas & Electric Company is authorized to procure between 500 Megawatts (MW) and 800 MW of electrical capacity in its territory to meet long-term local capacity requirements by the end of 2021. Procurement must abide by the following guidelines:

   a. At least 25 MW of local capacity must be procured from energy storage resources (as defined in Decision 13-10-040);

   b. At least 175 MW of local capacity must be procured from preferred resources consistent with the Loading Order of the Energy Action Plan (beyond the requirement of subparagraph (a) of this Ordering Paragraph). Bulk energy storage and large pumped hydro facilities shall not be excluded from this category.

3. Southern California Edison Company and San Diego Gas & Electric Company are authorized to procure bilateral contracts to meet authorized local capacity requirements as specified in this Order, including bilateral contracts consistent with the provisions of Public Utilities Code Section 454.6.

4. Southern California Edison Company and San Diego Gas & Electric Company shall work with the California Independent System Operator to determine a priority-ordered listing of the most electrically beneficial locations for preferred resources deployment.

5. Southern California Edison Company shall prioritize any procurement authorized by this decision in the West Los Angeles sub-area of the Los Angeles Basin local reliability area to the extent possible, and shall document efforts to comply with this Ordering Paragraph in its Application(s) required by Ordering Paragraph 8.

6. San Diego Gas & Electric Company (SDG&E) shall issue an all-source Request for Offers (RFO) for some or all capacity authorized by this decision in Ordering Paragraph 2. The RFO shall include the elements specified by Ordering Paragraph 4 of Decision (D.) 13-02-015, in addition to any RFO requirements not delineated herein but specified by previous Commission procurement decisions (including D. 07-12-052) and the authorization and requirements of this decision.

7. No later than 90 days after the effective date of this decision, San Diego Gas & Electric Company (SDG&E) shall submit a procurement plan to be reviewed and approved in writing by the Director of the Energy Division. SDG&E may propose in its procurement plan a separate, earlier application for gas-fired generation. The procurement plan shall include a proposed Request for

Offers as required by Ordering Paragraph 6. SDG&E shall not commence any procurement activities until the Director of the Energy Division approves its procurement plan, which shall be reviewed consistent with this decision. The SDG&E procurement plan shall be subject to the same procurement plan requirements of Ordering Paragraphs 6, 7 and 8 in Decision 13-02-015 as were required of Southern California Edison Company. In addition, SDG&E shall provide to Energy Division all of the information listed in Attachment B to this decision. If SCE issues one or more additional Requests for Offers to procure capacity pursuant to this decision, it shall also provide to Energy Division all of the information listed in Attachment B to this decision.

8. Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) shall each file one Application for approval of any and all contracts entered into as a result of the procurement process authorized by this decision. The requirements of Ordering Paragraph 11 of Decision 13-02-015 shall apply to both utilities. Neither SCE nor SDG&E shall receive recovery in rates for the costs related to any such contract before Commission review and approval of these Applications. In addition to currently applicable rules, the Applications shall specify how the totality of the contracts meet the following criteria:

a. Cost-effectiveness;
b. Consistency with the Loading Order, including a demonstration that it has identified each preferred resource and assessed the availability, economics, viability and effectiveness of that supply in meeting the LCR need;
c. Compliance with Ordering Paragraphs 1 or 2 (as applicable);
d. For applicable bilateral contracts, compliance with Public Utilities Code Section 454.6; and

e. A demonstration of technological neutrality, so that no resource was arbitrarily or unfairly prevented from bidding in SCE's or SDG&E's solicitation process. To the extent that the availability, viability and effectiveness of resources higher in the Loading Order are comparable to fossil-fueled resources, SCE and SDG&E shall show that it has contracted with these preferred resources first.

9. In its Application to implement this decision pursuant to Ordering Paragraph 8, Southern California Edison Company shall present contracts for at least 50 Megawatts (MW) of energy storage resources (pursuant to Ordering Paragraph 1) to the Commission for approval, or have the burden to show that it should procure less than 50 MW because the bids it received were unreasonable. The same requirements shall apply for San Diego Gas & Electric Company, except the requirement for energy storage resources shall be 25 MW.

10. Southern California Edison Company and San Diego Gas & Electric Company shall treat the retrofitting of a power plant cooling system, which is undertaken to comply with State Water Resources Control Board Statewide Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling and has a compliance deadline before December 31, 2022, as a new resource in considering resources to meet the procurement authorized in Ordering Paragraph 1 and 2.

11. Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) shall provide documentation in their respective Applications required by Ordering Paragraph 8 of efforts to consult with the California Independent System Operator to develop performance characteristics for local reliability, and how SCE and SDG&E meet any such performance characteristics.

12. Southern California Edison Company (SCE) may modify its procurement plan approved by Energy Division per Decision 13-02-015 solely so that

resources in portions of the Los Angeles Basin beyond the West Los Angeles sub-area may also be procured to meet incremental local capacity needs identified in this decision. Any such modification shall be submitted by SCE to Energy Division within 90 days of the effective date of this decision and shall be subject to the written approval of the Director of the Energy Division.

13. In applications for contract approval, Southern California Edison Company and San Diego Gas & Electric Company shall recommend a method of cost allocation appropriate for the resources being procured as authorized in this decision, either consistent with the cost allocation mechanism approved in Decision (D.) 06-07-029, D.07-09-044, D.08-09-012, D.11-05-005 and D.13-02-015 or through another Commission-authorized method.

14. The November 4, 2013 Motion of the Protect Our Communities Foundation for Official Notice of Exhibits, identified as Exhibits POC-3, POC-4 and POC-5, is denied.

15. The Southern California Edison Company Motion to Strike the Opening Brief of the City of Redondo Beach is denied.

16. The Southern California Edison Company and San Diego Gas and Electric Company Joint Motions to Strike the Opening Brief and Reply Brief of Protect Our Communities are granted.

17. The Southern California Edison Company, San Diego Gas & Electric Company and Pacific Gas and Electric Company Motions to Strike the Opening Brief of Marin Energy Authority are granted.

18. The Southern California Edison Company Motion to Partially Strike the Opening Brief of Nevada Hydro Company is granted.

19. Rulemaking 12-03-014 is closed.

This order is effective today.

Dated March 13, 2014, at San Francisco, California.

MICHAEL R. PEEVEY
President
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
CARLA J. PETERMAN
MICHAEL PICKER
Commissioners

ATTACHMENT A

No.	Party	Track 4 Need by Utility (Need is incremental to any authorization already provided for in the Track 1 decision)		Basis for Track 4 Need By Utility	
		SCE	**SDG&E**	**SCE**	**SDGE**
1. a)	**CAISO 80%**	1,922 MW	612	From the results of CAISO's LCR study assuming 80% of the needed identified in the SONGS area is allocated to the LA Basin and after deducting Track 1 authorization	From the results of CAISO's LCR study assuming 80% of the needed identified in the SONGS area is allocated to the LA Basin and after deducting Track 1 authorization
1. b)	**CAISO 2/3rds**	1,222 MW	1,177 MW	From the results of CAISO's LCR study assuming 2/3rds of the identified need in the SONGS Area is assumed to be in the LA Basin, and after deducting Track 1 authorization	From the results of CAISO's LCR study assuming 2/3rds of the identified need in the SONGS Area is assumed to be in the LA Basin, and after deducting Track 1 authorization
2.	**SCE**	500	NA	Incremental to preferred resources and transmission Needed to meet the higher reliability standards used by CAISO particularly relating to voltage support and to mitigate uncertainty in assumptions including load growth	NA

No.	Party	Track 4 Need by Utility (Need is incremental to any authorization already provided for in the Track 1 decision)		Basis for Track 4 Need By Utility	
		SCE	**SDG&E**	**SCE**	**SDGE**
3.	**SDG&E**	NA	1,320 – 1,470 MW without transmission improvement, could be reduce to 370 – 820 MW with major new transmission (Jontry at 10-11)[239]	NA	From results of SDG&E power flow study cases which included 408 MW of load reduction or new supply by 2022 from preferred resources that currently do not exist.

[239] Assumes approval of 300 MW Pio Pico Application currently before the Commission in A.13-03-019.

4.	**AES Southland[240] (AES)**	1000 MW (at 11)	MW Number Not Provided	Recommends that SCE be authorized to procure an additional 1,000 MW of generation in addition to what was approved at the conclusion of the Track 1 process. (at 11) AES strongly urges its recommendation for the following reasons: (1) procuring generation from outside the LA Basin area to replace SONGs may not be the most reliable nor cost-effective solution, (2) transmission solutions to reduce the need for procurement of generation from the most effective LA Basin generation locations may not result in the most robust or reliable system configuration. (3) Importing large amounts of generation, particularly when system demand undergoes sudden changes, will expose the system to voltage collapse conditions. (4) In addition, permitting and construction timelines for repowering existing OTC sites are likely to be considerably shorter than the timeline for developing greenfield transmission such as the Mesa Loop-In project and/or new generation. (at 10.)	NA

No.	Party	Track 4 Need by Utility (Need is incremental to any authorization already provided for in the Track 1 decision)		Basis for Track 4 Need By Utility	
		SCE	SDG&E	SCE	SDGE
5.	**AREM/DACC**	MW Number Not Provided	MW Number Not Provided	Takes no position on need to replace energy and capacity from loss of SONGS. (at 2)	Takes no position on need to replace energy and capacity from loss of SONGS (at 2)
6.	**Center for Energy Efficiencies and Renewable Technologies (CEERT)**	0 MW (at II-2)	0 MW (at II-2)	Recommends that the Commission make a final, not interim, Track 4 need determination based on consideration of the CAISO's 2013-2014 TPP, projected success of the 33% RPS program, and results of SCE's Track 1 preferred resource procurement and "living pilot" in order to avoid a piecemeal or premature overreliance on fossil procurement. (at II-2 – II-6). CEERT recommends a schedule to achieve that end that will permit a timely Proposed Decision in Track 4 by June 2014 and achieve the "early 2015" goal for any needed procurement by acceleration of the process *after* the issuance of that decision. (p. II-6, citing CEERT 9-10 Comments on Track 4 Schedule, at 5-6; see also, CEERT 10-14 Reply Comments on ALJ Questions, at 1-7).	

[240] Witness Hala N. Ballouz's Testimony

No.	Party	Track 4 Need by Utility (Need is incremental to any authorization already provided for in the Track 1 decision)		Basis for Track 4 Need By Utility	
		SCE	SDG&E	SCE	SDGE
7.	**California Environmental Justice Alliance (CEJA)**	0 MW (at 2)	0 MW (at 2)	CAISO's modeling assumptions were too conservative: • Updated 2013 CEC demand forecast for LA Basin and San Diego for 2022 is 1,320-3,200 MW lower than the 2012 CEC forecast CAISO used. • Transmission fixes, especially for reactive support, were found to reduce need by at least 1,500 MW and CAISO transmission planning results should be considered. • Preferred resources include 50 MW storage, 997 MW of DR, and 496 MW of DG. New CPUC storage proceeding targets should be considered in Track 4. (at 2) All resources authorized in Track 1should be assumed to be available in considering local capacity requirements for SONGS. California Energy Demand 2014-2024 Revised Forecast, and in particular the CEC's draft Estimates Of Additional Achievable Energy Savings should be considered. Contingency planning should not favor new GFG over renewable resources or short-term solutions.	

No.	Party	Track 4 Need by Utility (Need is incremental to any authorization already provided for in the Track 1 decision)		Basis for Track 4 Need By Utility	
		SCE	SDG&E	SCE	SDGE
8.	**California Energy Storage Alliance (CESA)**	MW Number Not Provided	MW Number Not Provided	CESA asserts that Energy storage is an important technology class for meeting LCR needs in general, including those in SCE's service territory. If the Commission finds need, it should allocate procurement authority to SCE that includes the procurement of Energy Storage. (at 2) CESA asserts that energy storage is an extremely diverse and modular resource class that addresses many of SCE's stated needs, including facilitating transmission upgrade deferral, and does so effectively (especially given SCE's definition of effectiveness for Preferred Resources). Storage resources are controllable and dispatchable (sometimes providing services almost instantaneously) and can provide services "across all or most of the times when needed," needed. Energy storage also has multiple resource subsets with diverse durations. (at 2)	

No.	Party	Track 4 Need by Utility (Need is incremental to any authorization already provided for in the Track 1 decision)		Basis for Track 4 Need By Utility	
		SCE	SDG&E	SCE	SDGE
9.	**City of Redondo Beach**	1,140 MW (1,140 = 2,940 MW SCE total need - 1800 MW, authorized for SCE in Track 1)	757 MW (757= 1,100 MW SDG&E total need – 343 MW authorized for SDG&E currently authorized)	Iterative power flow studies show that 940 MW of conventional gas-fired generation added at the Huntington Beach generating station PLUS 2,000 MW of preferred resources added throughout the Western LA Basin can meet the Western LA Basin sub-area LCR.	CAISO's 2012-2013 transmission plan for the no-SONGS case (City of Redondo Beach's original testimony [241]) and the CAISO's Track 4 base case (comments submitted by the City of Redondo Beach).
10.	**Clean Coalition (CCC)**	0 MW (at 8)	0 MW (at 8)	No new conventional generation and transmission investments until full value of renewable resources assessed through public procurement and planning process. (at 8)	

[241]. The (About 900 MW) mentioned in the City's original testimony for the generation assumed in the San Diego area by year 2022 for the no-SONGS study in the CAISO's 2012-2013 transmission plan is a typographical error. The correct number is 1,100 MW.

No.	Party	Track 4 Need by Utility (Need is incremental to any authorization already provided for in the Track 1 decision)		Basis for Track 4 Need By Utility	
		SCE	**SDG&E**	**SCE**	**SDGE**
11.	**Environmental Defense Fund (EDF)**	EDF presented data indicating that no additional combustion resources are needed with the use of preferred resources, such as EE and demand response.	EDF presented data indicating that no additional combustion resources are needed with the use of preferred resources, such as EE and demand response	EDF commended SCE's "Preferred Resources Scenario" approach, innovative pilot, and clear identification of the uncertain need for additional capacity. Recommends that the Commission refrain from rendering a decision until a comprehensive a set of analyses becomes available. (at 2-3)	EDF points to the ability of demand response, including time-variant rates, as well as energy efficiency, distributed generation and other clean resources, to address the range of capacity needs currently identified by different parties.

No.	Party	Track 4 Need by Utility (Need is incremental to any authorization already provided for in the Track 1 decision)		Basis for Track 4 Need By Utility	
		SCE	SDG&E	SCE	SDGE
12.	**EnerNOC Testimony**	MW Number Not Provided	MW Number Not Provided	It is reasonable to authorize additional capacity procurement for SCE, for as much as 500 MW, because SCE has adequate capacity, according to its studies, between the Track I authorization and the planned Mesa Loop-In transmission project unless the likelihood of realizing the transmission project is low. (at II-2-3; II-7-9). Before authorizing SCE to procure additional resources beyond its Track I authorization, the Commission must resolve the calculation difference between SCE's and CAISO's analysis. (at II-2, II-7-6-8) The Commission should not authorize additional capacity procurement until the CAISO has completed its 2013-14 Transmission Planning Process. (at II-3, II-9-11) Further, the Commission should reject the CAISO's and utilities' objections to updating assumptions and any efforts to impose inappropriate conditions on demand response reducing or meeting local need. Any Track 4 need determination must be consider all updated assumptions (i.e., CAISO's TPP results, Track 1 solicitations/pilots results, and further development of DR programs) through at least the first quarter of next year before any Track 4 procurement is authorized.	SDG&E's calculation of its incremental resource need appears to be reasonable. (at III-31, II-12.) SDG&E's analysis of need is consistent with CAISO's, which shows an incremental need between 620 and 147 MW, after adjusting for Track 1 authorized procurement. (at II-12.) SDG&E's proposal is only partially consistent with the loading order. (at II-11-12). As in the case of SCE, the Commission should also use updated assumptions in identifying

No.	Party	Track 4 Need by Utility (Need is incremental to any authorization already provided for in the Track 1 decision)		Basis for Track 4 Need By Utility	
		SCE	SDG&E	SCE	SDGE
13.	**Independent Energy Producers (IEP)**	2,506 MW (including the Track 1 solicitation of 1,400-1,800 MW). If full 1,800 MW from Track 1 is procured, then Track 4 authorization should be 706 MW (2,506 – 1,800) (at 30)	820 MW However, if Commission does not approve the Pio Pico application, then resource need would increase to 1,118 MW (820 + 298). (p. 30)	Factors in SCE's and SDG&E's service area drive uncertainty in forecasting, which can result in under-estimating need and threatening grid, include (1) net load forecasts in local resources are subject to significant uncertainty because of energy reduction and uncertainty as to demand; (2) slow economic recovery could accelerate increasing demand; (3) some preferred resources may not prove viable skewing load forecasts; (4) new and upgraded transmission may be delayed. (at 12-14) While over-capacity might result in slightly higher costs, under-capacity would come with a very high social cost. (at 15) Track 4 authorization should be based on total resource need in Track 4 studies. (PHC Comments, at 2.)	
14.	**National Resources Defense Council (NRDC)**	SCE's local capacity need for LA Basin should be reduced by 543 MW under either CAISO or SCE models. (at 13)	SDG&E's local capacity need should be reduced by 211 MW as compared to SDG&E's model results or 342 MW as compared to CAISO's modeling results. (at 13)	Reductions justified because energy efficiency assumptions were substantially underestimated. (at 13) Further reductions may be justified from inclusion of CAISO's 2012/2013 transmission plan results and the CEC's 2013 managed demand forecast results. (Testimony, at 9; Comments, at 2)	

No.	Party	Track 4 Need by Utility (Need is incremental to any authorization already provided for in the Track 1 decision)		Basis for Track 4 Need By Utility	
		SCE	**SDG&E**	**SCE**	**SDGE**
15.	**NRG Testimony**	MW Number Not Provided	MW Number Not Provided	Loss of SONGS creates substantial need for new resources in LA and San Diego areas. (at 5.) The loss of 2,246 MW of real power support and 1,100 MVAR of reactive power support degrades the reliability of the local bulk power system. (at 6.)	

No.	Party	Track 4 Need by Utility (Need is incremental to any authorization already provided for in the Track 1 decision)		Basis for Track 4 Need By Utility	
		SCE	SDG&E	SCE	SDGE
16.	**Office of Ratepayer Advocates (ORA)** [242]	MW Number Not Provided	MW Number Not Provided	CPUC should deny SCE's and SDG&Es request for authorization. (at 8-9.) Recommends conservative procurement authorization that while ensuring reliability would minimize costs to ratepayers. (at 13) Recommends need determination and procurement authorization should be based on supplemental joint power flow studies that show the effect of all SCE and SDG&E identified LCR need reduction solutions on the entire SONGS study area. Studies submitted by SCE and SDG&E are insufficient. (at 14-15) The current record lacks adequate information to determine need and optimize procurement allocation for the SONGS study area, so ORA recommends that the Commission find 0 MW of need at the present time. (10/17 email) Although ORA believes that the current record is inadequate to determine need in the SONGS study area, if the Commission nevertheless finds need, it should allocate procurement authority to SCE and SDG&E in manner that minimizes overall procurement, ratepayer costs and greenhouse gas emissions while maintaining reliability in the SONGS study area. (For example, the CAISO determined that overall procurement would be less if 33.3% were located in SDG&E's service territory and 66.7% in SCE's service territory.) (10/17 email)	

242 Witness Radu Ciupagea.

No.	Party	Track 4 Need by Utility (Need is incremental to any authorization already provided for in the Track 1 decision)		Basis for Track 4 Need By Utility	
		SCE	**SDG&E**	**SCE**	**SDGE**
17.	**PG&E**[243]	3,302 MW (Table 2-1, at 2-4 of reply testimony)	1,770 MW (Table 2-1, at 2-4 of reply testimony)	Figure II-1 of SCE Track 4 opening testimony, at 8. For SCE, PG&E uses the LA Basin Generation scenario and recommended additional 500 MW of procurement authorization as the identified need.	Table 3 of SDG&E Track 4 opening testimony of John M. Jontry, at 12

[243] The numbers cited for Track 4 need by utility represent PG&E's recommendation for a need determination. The need determination should identify the full incremental need (in MW) to meet southern California's local reliability needs given the Track 4 power flow study assumptions made by SCE and SDG&E. These numbers are not incremental to procurement authorized in Track 1 of the 2012 LTPP. To the extent that resources are procured through authorization granted in Track 1 of the 2012 LTPP or other recent procurement authorizations, this need can be met by those estimated amounts to the extent deemed effective at meeting the identified need. Likewise, to the extent that transmission solutions are approved, verified to reduce local reliability needs without building new generation, and on track to be completed in the necessary timeframe, the need can also be met by those estimated amounts to the extent deemed effective at meeting the identified need.

No.	Party	Track 4 Need by Utility (Need is incremental to any authorization already provided for in the Track 1 decision)		Basis for Track 4 Need By Utility	
		SCE	SDG&E	SCE	SDGE
18.	**Protect Our Communities (POC)**	NA	0 MW	NA	No additional authorization should be made at this time. Current CAISO N1-1 criterion is an unreasonable reliability measure to base Local Capacity Requirement need for SDG&E. In addition, the retirement of the Encina OTC should not be assumed when determining LCR need. Further, the San Diego local area must include the 1080 MW in generation assets connected to SDG&E's Imperial Valley substation.

No.	Party	Track 4 Need by Utility (Need is incremental to any authorization already provided for in the Track 1 decision)		Basis for Track 4 Need By Utility	
		SCE	SDG&E	SCE	SDGE
19	Sierra Club	0 MW (at 1)	0 MW (at 1)	Considering load shedding, the latest CEC demand forecast, and the Mesa Loop-In Transmission Upgrade eliminates the need that CAISO identified in its Track 4 studies. Also, the assumptions do not include enough energy efficiency, demand response, energy storage, or distributed generation; accounting for these resources would eliminate need. Finally, CAISO's N-1-1 reliability standard is overly conservative and resulted in an overinflated estimate of need.	Assuming use of the standard G-1, N-1 SDG&E limiting contingency (which would add 1,080 MW of existing combined cycle generation to LCR capacity), the latest CEC demand forecast, and load shedding eliminates the need that CAISO identified in its Track 4 studies. Also, the assumptions do not include enough energy efficiency, demand response, energy storage, or distributed generation; accounting for these resources would eliminate need. Finally, CAISO's reliability standard (N-1-1 contingency) is overly conservative, and resulted in an overinflated estimate of need.

No.	Party	Track 4 Need by Utility (Need is incremental to any authorization already provided for in the Track 1 decision)		Basis for Track 4 Need By Utility	
		SCE	**SDG&E**	**SCE**	**SDGE**
20.	**The Utility Reform Network (TURN)**	500 MW (at 9)	500 MW (at 9)	TURN believes there is no "grand plan" to answer the Southern California Reliability needs but that the Commission will need to incrementally consider from a series of competing measures to gradually meet such needs. (at 4-5.)	

No.	Party	Track 4 Need by Utility (Need is incremental to any authorization already provided for in the Track 1 decision)		Basis for Track 4 Need By Utility	
		SCE	SDG&E	SCE	SDGE
21.	**Vote Solar**	Before authorizing any additional resource procurement in Track 4, SCE should first fulfill entire Track 1 Preferred Resources (PR) procurement authorization and develop the Mesa Loop-In.	Before authorizing any additional resource procurement in Track 4, SDG&E should first fulfill entire Track 1 PR procurement.	If additional resources are still needed, Vote Solar recommends using only PR and storage, phased-in over time as needed with annual solicitations; leverage Distributed Energy Resources (DER), storage & PV-DG to meet LCR in-basin and ensure reliability; use Living Pilot to test interoperability; include smart grid in Living Pilot; and ensure pilot-to-deployment process is developed. Too maximize PV-DG, orient PV to west to address afternoon ramp and use intelligent inverters to provide voltage support on distribution grid; include both in Living Pilot. No need for land set aside for future generation development or options contracts for gas (though preferable to SDG&E Energy Park proposal)	If additional resources are still needed, Vote Solar recommends using only PR and storage, phased-in overtime as needed with annual solicitations; leverage Distributed Energy Resources (DER), storage & PV-DG to meet LCR in-basin and ensure reliability; and develop a parallel pilot to SCE's Living Pilot or participate in SCE's Living Pilot. No need for Energy Park proposal.

No.	Party	Track 4 Need by Utility (Need is incremental to any authorization already provided for in the Track 1 decision)		Basis for Track 4 Need By Utility	
		SCE	SDG&E	SCE	SDGE
22.	**Wellhead Electric**	MW Number Not Provided	MW Number Not Provided	In comparison to conventional gas-fired generation, the fast acting attribute of energy storage is valuable to the grid with fewer efficiency losses; is also more accurate at tracking fast changing regulation signals. Any procurement authorization should include all resources with attributes able to meet local area needs and ensure that certain classes of resources are not excluded from participation and, as a result, from consideration by the utility customer.(at 7. tyvm. Kerner)	
23.	**Women's Energy Matters (WEM)**	NA	NA	NA	NA
24.	**Western Power Trading Forum (WPTF)**	500 MW (at 4) Recommends all-source RFO as opposed to mandating which specific resources should be used.	NA	SONGS is now permanently retired and the Commission and the affected utilities need to move forward expeditiously to meet the affected need. (at 4)	NA

(END OF ATTACHMENT A)

ATTACHMENT B

SDG&E Procurement Plan Requirements

In the proposed procurement plans to be reviewed by Energy Division, SDG&E shall include all of the following:

1. **Overall description of procurement process:** Major procurement steps, such as soliciting bids, bid evaluation, selection of bids/signing contracts, filing application for Commission approval, expected decision, on-line date. Also include details on contingent contract process including triggers that would necessitate the execution of contingent contracts, option cost, contract terms, and a detailed break up of costs. Describe which elements of the solicitation will be made public.

2. **Timeline**: The procurement plan should contain a detailed timeline that includes an estimate for when resources with specific megawatt quantities are expected to come online up to the year of authorization. The timeline should also include:

    a. Major procurement steps, such as soliciting bids, bid evaluation, selection of bids/signing contracts, filing application for Commission approval, expected decision, and on-line date

    b. A sub-timeline for any contingent contracts

    c. Major decision points for backup procurement when resources do not materialize

3. **Locational details**: Indicate the substations and the locational effectiveness of the sites where the utility plans to procure resources.

4. **Description and quantification of how authorized demand-side resources are incremental**: Detail plans to distinguish resources procured for the purpose of meeting LCR capacity/ energy from resources procured within existing IOU-DSM programs like energy efficiency and demand response.

    a. **For energy efficiency**: Establish baseline planning assumptions that reflect LTPP planning assumptions. Detail how the utility will direct bidders to propose resources whose procurement would exceed the baseline, such as resources with strong economic potential that face a market barrier, resources that are cost-competitive with other resources because of transmission constraints, or vendor identification of "to energy efficiency program baseline" and "above energy efficiency program baseline" savings. State the methodology and assumptions by which the utility will conduct an assessment to quantify the energy efficiency program baseline and the capacity and energy saving values of the incremental resources, including such data sources as impact evaluation studies, engineering estimates, before-and-after operational data using advanced metering infrastructure, or approved measure-based M&V. Document how the assessment uses methods and assumptions consistent with current Commission adopted policy concerning the estimation of savings for energy efficiency projects and measures.

b. **For demand response:** Similar to energy efficiency, demand response load impact from the selected bids should be incremental to the CEC load forecast and the supply assumptions used for this decision. In addition, establish RFO criteria that are consistent with all approved Commission decisions in the demand response rulemaking (R.13-09-011), Commission resolutions addressing demand response, Electric Rule 24, and any approved California ISO determinations of operational characteristics required of demand response to meet local reliability needs. The RFO criteria should provide flexibilities for meeting future adopted demand response policy if the Commission decisions in the demand response rulemaking (R.13-09-011) are pending. Detail how the utility will direct bidder to propose resources capable of meeting these criteria. State the methodology by which the utility will quantify and verify the operation of demand response resources to meet local reliability needs.

5. **LCR and flexible attributes**: Describe the LCR and flexible attributes of the various technology-specific resources considered for procurement. Apply RA counting rules and the ISO "Non Transmission Alternatives"

study in most cases. In cases where there are no defined attributes for a resource, propose attributes with a detailed rationale.

6. **Procurement Process**: Include detailed description of the procurement process resources, specifying the structure of any RFO, bilateral contract, existing procurement programs or alternative procurement process and related timelines. Include information on structure of offers, selection, short listing, and cost competitiveness threshold.

7. **Include evaluation details**. Include a detailed description for evaluating resources which contains the following information:

    a. A process to evaluate different resources in a non-discriminatory fashion

    b. A method to quantify costs and benefits related to capacity, energy, flexibility, GHG, ancillary services etc. for all resources

    c. Standardized assumptions for costs and benefits across resource type

    d. A method to capture non-energy and other quantitative benefits

8. **Include CAM details:** Indicate which resources should be subject to CAM treatment. Indicate which procured resources will count towards IOU program goals.

9. **Project details**: Include details on how its plans to evaluate the viability of preferred resource projects. Also include the following project details for each technology type:

    a. Desired start dates for delivery

    b. Acceptable contract durations

    c. Minimum size in terms of capacity

    d. Interconnection requirements

10. **Other Details**: Include information on the following.

a. Bidder outreach before and after the solicitation including details like bidder conferences, advertisements, and webinars

b. Participation of disadvantaged business enterprises

c. Independent Evaluator (IE) details and IE role

11. **Other statutes affecting procurement:** Cite relevant state laws and Commission decisions influencing this procurement. List potential challenges.

12. **Documents:** Include non-binding pro form as and draft solicitation documents.

(END OF ATTACHMENT B)

EXHIBIT D

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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.	Application 14-11-016 (Filed November 26, 2014)

RESPONSE OF NRG ENERGY CENTER OXNARD LLC
AND NRG CALIFORNIA SOUTH LP TO
APPLICATIONS FOR REHEARING OF DECISION 16-05-050

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TABLE OF CONTENTS

TABLE OF AUTHORITIES

Page(s)

COMMISSION DECISIONS AND RESOLUTIONS

CASES

STATUTES

REGULATIONS

BEFORE THE PUBLIC UTILITIES COMMISSION
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AND NRG CALIFORNIA SOUTH LP TO
APPLICATIONS FOR REHEARING OF DECISION 16-05-050

Pursuant to Rule 16.1(d) of the Rules of Practice and Procedure ("Rules") of the California Public Utilities Commission ("Commission"), NRG Energy Center Oxnard LLC ("NECO") and NRG California South LP ("NRG South") (collectively, "NRG") submit this response to the Applications for Rehearing of Decision ("D.") 16-05-050 (the "Decision") ("Applications for Rehearing" or "AFRs") filed by the California Environmental Justice Alliance and Sierra Club ("CEJA/Sierra Club"), the Center for Biological Diversity ("CBD"), and the City of Oxnard ("City") (collectively, the "Filing Parties").

I. INTRODUCTION

The Decision approved, in part, the results of the Southern California Edison Company ("SCE") 2013 Local Capacity Requirements ("LCR") Request for Offers ("RFO") for the Moorpark sub-area of the Big Creek/Ventura local reliability area. SCE conducted its LCR RFO in accordance with the requirements of D.13-02-015 issued in the 2012 long-term procurement plan ("LTPP") proceeding. D.13-02-015 required SCE to procure between 215 and 290 megawatts ("MW") of electrical capacity in the Moorpark sub-area to meet LCR needs by 2021, largely due to the assumed retirement of approximately 2,000 MW of gas-fired generating capacity at facilities that use once-through cooling technology ("OTC").[1] The Decision approved nine of the 11 contracts executed by SCE, and deferred consideration of the remaining two contracts to a subsequent phase of this proceeding. One of the approved contracts is a resource adequacy purchase agreement with NECO for a new 262 MW gas-fired peaking facility known as the Puente Power Project ("Puente Project") (the "Puente Contract").[2]

The Filing Parties opposed approval of the Puente Contract throughout the proceeding. The Applications for Rehearing reargue positions taken by the Filing Parties in the proceeding, which were considered and rejected in the Decision. CEJA/Sierra Club reargue CEJA's position that the Commission cannot lawfully approve the Puente Contract because SCE did not adequately consider potential environmental justice impacts, and did not state a preference in its LCR RFO for renewable projects located in Oxnard. The Decision correctly rejected those arguments, and found that the language that CEJA relies on regarding consideration of environmental justice impacts in an RFO "should be viewed as guidance." The Decision properly concluded that SCE's selection of the Puente Contract was consistent with Commission orders requiring utilities to use brownfield sites first, and substantially complied with the procurement directives in D.13-02-015.

All of the Filing Parties reargue their positions that the California Environmental Quality Act ("CEQA") requires the Commission to conduct an environmental review of the Puente Project, or await completion of the environmental review being conducted by the California Energy Commission ("CEC"). The Commission has consistently held for decades that its approval of a utility power purchase agreement is not a "project" as defined in CEQA. Contrary

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[1] D.13-02-015, Ordering Paragraph 2, Findings of Fact 5, 38, 39, 40, 41, 42, Conclusion of Law 11.

[2] Decision at 2, 26, Ordering Paragraph 1; Exhibit ("Exh.") SCE-1 (Bryson) at 55:16 through 56:5; Exh. NRG-1 (Gleiter) at 2:2-8.

to the Filing Parties' arguments, the Commission is not a CEQA responsible agency or the CEQA lead agency for the Puente Project.

CBD argues that approval of the Puente Contract violated the loading order ("Loading Order"), but CBD's argument is without merit. The record showed that it was not possible for SCE to meet the minimum capacity required by D.13-02-015 using only preferred resources, and that a gas-fired resource must be part of the Moorpark reliability solution. The Decision correctly found that the Puente Project is necessary to meet identified local reliability needs, and provides grid reliability benefits at a reasonable cost to ratepayers. The Decision's findings did not violate the Loading Order, which the Commission has confirmed must be balanced with the State's reliability and economic needs.

CEJA/Sierra Club also reargue CEJA's position that SCE improperly selected the Puente Contract based on an unsubstantiated concern that NRG South could retire existing non-OTC peaking facilities if SCE did not contract with NRG for a new plant. The Decision correctly rejected CEJA's argument. The Decision concluded that, while qualitative factors reinforced SCE's selection of the Puente Contract, the selection was supported by a quantitative assessment which demonstrated that the Puente Contract was the best resource available from the LCR RFO.

CBD argues that the LCR RFO did not comply with Commission requirements, but CBD has not identified any legal error in the Decision. CBD argues that SCE impermissibly solicited offers for resources to be operational before 2021, but SCE followed its procurement plan, which was approved by the Energy Division, when it solicited offers with potential early online dates. This was consistent with D.13-02-015, which did not prohibit resources coming online before 2021. CBD's argument also does not apply to the Puente Contract, which specifies a 2020 online date. CBD's arguments regarding contract availability and security requirements for preferred resources also lack merit. SCE has demonstrated that its LCR RFO solicited offers from all resource types, and did not discourage preferred resources from participating.

Finally, CBD argues that the Commission should have reviewed the validity of the need determination adopted in D.03-02-015 based on changed circumstances and CBD's arguments in this proceeding. CBD's argument is without merit. The Commission is not required to reevaluate the need determination adopted in an LTPP decision when it approves contracts executed to fill the authorized need. The Commission's established procurement and planning process is to determine utility LCR need in general procurement decisions, such as D.13-02-015, and not to reconsider those need determinations when approving contracts proposed to fill the approved need absent an unforeseen emergency. It was not legal error for the Commission to follow its preferred practice of not reconsidering the need determination adopted in D.13-02-015.

As the Commission recently confirmed, "[r]ehearing applications are not a proper vehicle to merely reargue positions taken during a Commission proceeding," and "are limited by [California Public Utilities Code ("PU Code")] section 1732 to specifications of legal error."[3] Because the Filing Parties have not specified any legal error, the Applications for Rehearing should be denied.

II. DISCUSSION

A. The Commission Correctly Concluded That Dicta in D.07-12-052 Regarding Environmental Justice Considerations is Guidance.

CEJA/Sierra Club argue that the Commission cannot lawfully approve the Puente Contract because SCE's evaluation of offers in the LCR RFO failed to "provide greater weight" to "disproportionate resource sitings in low income and minority communities," which is one of the qualitative evaluation criteria listed in D.07-12-052. CEJA/Sierra Club argue that SCE was required to consider this qualitative factor because Ordering Paragraph 4 of D.13-02-015

[3] D.16-05-053 at 12, citing D.12-12-040 at 3.

required that SCE's LCR RFO "shall include . . . any RFO requirements not delineated herein but specified by previous Commission procurement decisions (including Decision 07-12-052)."[4]

CEJA/Sierra Club merely reargue the position taken by CEJA and addressed extensively in the proceeding. The Decision concluded that the language that CEJA relies on from D.07-12-052 "should be viewed as guidance" that remains in effect.[5] The Decision did not, however, invalidate the LCR RFO as urged the CEJA. Instead, the Decision explained that:

> The dicta cited above from D.07-12-052 remains in effect as guidance, but the Commission to date has not yet provided further specificity regarding how the utilities should implement this guidance. D.07-12-052 provided a wide variety of other direction in Ordering Paragraphs to utilities regarding procurement activities (as have several subsequent decisions in LTPP proceedings, including D.13-02-015 and § 454.5).[6]

The Decision also recognized that the Puente Project will be built at the site of an existing power plant, which is a brownfield site, and found that D.07-12-052 provided "specific direction regarding brownfield siting in an Ordering Paragraph."[7] The Decision cited Ordering Paragraph 35 from D.07-12-052, which specifies that: "IOUs are to consider the use of Brownfield sites first and take full advantage of their location before they consider building new generation on Greenfield sites. If IOUs decide not to use Brownfield, they must make a showing that justifies their decision."[8] By selecting a project located at a brownfield site (and the site of existing OTC units), SCE followed the order in D.07-12-052 to use brownfield sites first for the

4 CEJA/Sierra Club AFR at 7-8.

5 Decision at 16-17, Finding of Fact 3 ("D.07-12-052 included dicta regarding environmental justice considerations in procurement solicitations."), and Conclusion of Law 3 ("Dicta from D.07-12-052 regarding environmental justice considerations in procurement solicitations should be viewed as guidance.").

6 *Id.* at 17.

7 *Id.*

8 *Id.* at 14, quoting Ordering Paragraph 35 from D.07-12-052.

siting of new generation projects. The Decision properly concluded that procurement of the Puente Contract substantially complied with the procurement directives in D.13-02-015.[9]

CEJA/Sierra Club argue that the Commission erred in characterizing the environmental justice considerations in D.07-12-052 as "dicta" and "guidance," but they are wrong. The Commission refers to statements in the body of a Commission decision as "dicta,"[10] and has held that statements in its decisions outside of Ordering Paragraphs, Findings of Fact, and/or Conclusions of Law are not part of the Commission's formal decision.[11] Where dicta are in tension with an Ordering Paragraph, the latter "takes precedence."[12] In addition, courts have distinguished between "recommendations" made in the body of a Commission decision, and orders issued in Ordering Paragraphs.[13] Because the Ordering Paragraphs, Conclusions of Law, and Findings of Fact in D.07-12-052 did not require utilities to consider impacts to low-income and minority communities, the Decision correctly noted that those statements are dicta that are "guidance," and that any such guidance must be "balance[d with] the Commission's long-standing preference for brownfield site development . . . as well as other economic and reliability considerations."[14]

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[9] *Id.* at Conclusion of Law 1.

[10] D.02-04-056 at 4 and 5, fn. 2.

[11] *See, e.g.,* D.89-04-048, 31 CPUC 2d 465 (*City of Healdsburg v. Pacific Gas and Electric Company*) at Conclusion of Law 2 ("Assuming for the sake of argument that the ordering paragraphs and a paragraph in the body of the decision are inconsistent, the ordering paragraphs are the final decision of the Commission. The ordering paragraphs are not subject to modification by a prior inconsistent statement contained in the body of the decision").

[12] *Id.*

[13] *Hillsboro Properties v. Pub. Util. Comm'n* (2003) 108 Cal. App. 4th 246, 259-260 ("In its Decision, the PUC took care not to overstep its jurisdiction. It recommended that the City amend the Ordinance to `disentangle CPUC utility rate setting jurisdiction and its own rent control jurisdiction' (Decision at p. 15), but the ordering paragraphs are directed only to Hillsboro [Properties].")

[14] Decision at 19.

The Commission's interpretation of its own decisions "is entitled to consideration and respect by the courts."[15] Courts will defer to the Commission's interpretation of its own decisions where the Commission's interpretation is reasonable and consistent with the prior decision's rationale.[16] In the Decision, the Commission exercised this discretion in interpreting the relevant procurement requirements imposed by D.07-12-052 and D.13-02-015, and found that "[d]icta from D.07-12-052 regarding environmental justice considerations in procurement solicitations should be viewed as guidance."[17] This conclusion is reasonable and, as explained above, is consistent with longstanding principles of Commission jurisprudence. CEJA and Sierra Club offer no valid justification for overturning this interpretation on rehearing.

CEJA/Sierra Club also assert that the Decision's characterization of language as "dicta" equates to a finding that the language is "mere surplusage" or "meaningless," but they are wrong. The Decision did not find that the dicta regarding environmental justice considerations is surplusage or meaningless, but instead clarified that such dicta is "guidance" that "remains in effect."[18] This is entirely consistent with D.07-12-052. In D.07-12-052, the Commission stated that "[w]e discuss below certain bid evaluation metrics that we urge the utilities, in conjunction with Independent Evaluators, Procurement Review Groups and Energy Division, to consider when developing the RFO bid documents and process," and explained that it was providing "general guidance to the IOUs" regarding the types of evaluation criteria that should be applied to bids in RFO:

> We understand that the [least cost best fit] framework cannot entirely be reduced to mathematical models and rules that completely eliminate the use of qualitative factors. However, the

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[15] *Clean Energy Fuels Corp. v. Pub. Utilities Comm'n* (2014) 227 Cal. App. 4th 641, 649 ("*Clean Energy Fuels*"); *So. Cal. Edison Co. v. Pub. Util. Comm'n* (2000) 85 Cal. App. 4th 1086, 1096.

[16] *Clean Energy Fuels*, 227 Cal. App. 4th at 655.

[17] Decision at Conclusion of Law 3.

[18] *Id.* at 17.

> IOU must be able to fully justify why a particular project wins a solicitation, and *we provide here some general guidance to the IOUs regarding the types of evaluation criteria that should be applied to bids in RFOs for the resources authorized in this decision*.
>
> The bid criteria raised specifically by parties in testimony, including credit and collateral, debt equivalence, Fin(46), and transmission costs/savings, are discussed in further detail in the following sections. Other obvious criteria include capacity and energy benefits, resource diversity, portfolio fit, local reliability/resource adequacy, and congestion costs. Some criteria for which we believe the IOUs need to provide greater weight include disproportionate resource sitings in low income and minority communities, and environmental impacts/benefits (including Greenfield vs. Brownfield development).[19]

Thus, it is clear that environmental justice considerations are one qualitative consideration among the many cited in dicta in D.07-12-052 that are "general guidance" to utilities. In contrast, as recognized in the Decision, Ordering Paragraph 35 in D.07-12-052 expressly *ordered* utilities to use brownfield sites first, and to take full advantage of their location before they consider building new generation on greenfield sites. SCE complied with the Commission' s order by selecting the Puente Contract.[20]

CEJA/Sierra Club also wrongly insist that the dicta regarding environmental justice considerations cannot be guidance because the qualitative criteria from D.07-12-052 are "enshrined" in the Procurement Manual for utilities.[21] The Procurement Manual repeats the guidance from D.07-12-052. This does not contradict or undermine the Decision' s conclusion that dicta in D.07-12-052 regarding environmental justice considerations "should be viewed as

19 D.07-12-052 at 156-157 (emphasis added).

20 The requirement in Ordering Paragraph 35 of D.07-12-052 specifying that utilities must use brownfield sites first is also stated in D.07-12-052 in Finding of Fact 103 and Conclusion of Law 55, and in D.04-12-048 in Finding of Fact 101 and Conclusion of Law 38.

21 CEJA/Sierra Club AFR at 7.

guidance."[22] The Procurement Manual also requires utilities to procure brownfield sites first, and states that: "Preference should be give [sic] to procurement that will encourage the retirement of aging plants, inefficient facilities with once–through cooling, by providing, at minimum, qualitative preference to bids involving repowering of these resources or bids for new facilities at locations in or near the load pockets in which these resources are located."[23] Further, the Procurement Manual was developed by the Energy Division, and is not a Commission decision. It cannot dictate how the Commission interprets its decisions.

CEJA/Sierra Club also incorrectly argue that dicta regarding environmental justice considerations cannot constitute guidance because "no additional guidance is required for an IOU to consider whether its procurement impacts low-income or minority communities."[24] This reflects CEJA's continued insistence that environmental justice considerations in an RFO must outweigh all other factors. D.07-12-052 did not specify that utilities must give disproportionate consideration to environmental justice factors over other considerations. D.07-12-052 also did not specify that qualitative considerations would override the utilities' quantitative analysis of which resources are the lowest cost and best fit for the utility's need. Utilities have flexibility to apply relevant qualitative considerations in their RFO resource evaluations, as long as they "fully justify why a particular project wins a solicitation."[25]

SCE has fully justified why the Puente Contract was a winning contract in the LCR RFO. SCE's testimony and the Independent Evaluator's report show that SCE selected the winning contracts for the Moorpark sub-area based primarily on its quantitative analysis of net market value – namely, the value of a resource's energy, ancillary services, and capacity benefits, minus

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[22] Decision at Conclusion of Law 3.

[23] Procurement Manual at 4.9, citing D.07-12-052 at 2.6.

[24] CEJA/Sierra Club AFR at 7.

[25] D.07-12-052 at 158.

fixed and variable offer-related costs.[26] SCE showed that it was not possible to procure the required minimum level of incremental capacity for Moorpark using only preferred resources, and demonstrated that a gas-fired project must be part of the Moorpark reliability solution.[27] SCE demonstrated that the Puente Contract was the most cost effective gas-fired offer.[28] As noted above, the Puente Project will be located at the site of existing OTC units that are scheduled to retire at the end of 2020.[29] SCE's selection of a new plant at an OTC site is supported by the Commission's findings in D.13-02-015 that: "Gas-fired resources at the current OTC sites are certain to meet the ISO's criteria for meeting LCR needs"; and "The most likely locations for [sic] to meet LCR needs in the Moorpark sub-are are the sites of the current OTC plants."[30] As discussed above, selection of the Puente Contract also satisfies the mandates in D.07-12-052 and D.04-12-048 that require utilities "to consider the use of brownfield sites first and take full advantage of their existing location before they consider building new generation on greenfield sites."[31]

B. Approval of the Puente Contract Did Not Violate PU Code Section 399.13(a)(7).

CEJA/Sierra Club reargue another position advanced by CEJA in this proceeding, namely CEJA's claim that SCE violated PU Code section 399.13(a)(7) because SCE "did not, in either its solicitation or procurement efforts, express any preference for renewables in Oxnard."[32] The Decision considered and rejected that argument, and found that "as CEJA itself notes, this

[26] Exh. SCE-1 (Singh) at 30-49; Exh. SCE-2, Appendix D (Independent Evaluator Report) at 5.

[27] Exh. SCE-7 (Cushnie) at 1:20 through 2:1; Exh. SCE-7 (Bryson) at 14:16-18.

[28] Exh. SCE-1 (Singh) at 30-49, 46:1-2; Exh. SCE-2, Appendix D (Independent Evaluator Report) at 39.

[29] Exh. SCE-1 (Bryson) at 56:4-5.

[30] D.13-02-015 at Findings of Fact 26 and 38.

[31] D.04-12-048 at 159, Finding of Fact 101, Conclusion of Law 38; D.07-12-052 at 230, Finding of Fact 103, Conclusion of Law 55, Ordering Paragraph 35.

[32] CEJA/Sierra Club AFR at 9.

section is on its face applicable to Commission review of renewable procurement."[33] The Decision concluded that: "Pub. Util. Code § 399.13 does not apply to all-source procurement contracts."[34]

CEJA/Sierra Club argue that the Decision is wrong, because SCE's LCR RFO was an all source RFO that sought offers for renewable resources alongside other resource types,[35] but their argument contradicts the statute. PU Code section 399.13 specifies requirements for utilities' renewable energy procurement plans to meet California's Renewables Portfolio Standard ("RPS"). PU Code section 399.13(a)(7) states that "[i]n soliciting and procuring eligible renewable energy resources for California-based projects, each electrical corporation shall give preference to renewable energy projects that provide environmental and economic benefits to communities afflicted with poverty or high unemployment, or that suffer from high emission levels of toxic air contaminants, criteria air pollutants, and greenhouse gases." The Moorpark LCR RFO was not conducted to meet RPS requirements pursuant to a renewable energy procurement plan governed by PU Code section 399.13. The Decision correctly found that PU Code section 399.13(a)(7) is not applicable in this context.

However, even if PU Code section 399.13(a)(7) applies to an all source LCR RFO, CEJA/Sierra Club's argument regarding preference fails, because SCE selected every renewable resource final offer submitted for the Moorpark sub-area.[36] Selection of all renewable offers is evidence that SCE did not fail to give preference to any renewable resource offers, including any offers that provide the benefits identified in PU Code section 399.13(a)(7).

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[33] Decision at 17.

[34] *Id.* at Conclusion of Law 4.

[35] CEJA/Sierra Club AFR at 8.

[36] Exh. SCE-7 (Bryson) at 14:2-3; Exh. SCE-7 (Cushnie) at 1:20 through 2:1.

C. Approval of the Puente Contract Did Not Violate Government Code Sections 65040.12(e) and 11135.

CEJA/Sierra Club argue that approval of the Puente Contract violates Government Code sections 65040.12 and 11135,[37] but neither statute applies to the Commission's review of the Puente Contract. Government Code section 65040.12 requires the Governor's Office of Planning and Research to coordinate the use of environmental justice data in land use plans. Governmental Code section 65040.12, subsection (e) defines the term "environmental justice" for purposes of section 65040.12, and does not, as CEJA/Sierra Club argue, impose any requirement that applies in this proceeding.[38] Likewise, Government Code section 11135 and implementing regulations, aimed at avoiding discrimination based on race, national origin, ethic group identification, religion, age, sex, sexual orientation, color, genetic information, or disability in programs administered or funded by the State, are wholly irrelevant.[39] State funds are not involved in the Puente Contract. Similarly, the list of State laws cited by CEJA/Sierra Club in footnote 37 of their Application for Rehearing are inapplicable on their face.

D. This Proceeding Appropriately Focused on Whether SCE Followed the Procurement Plan Approved by the Energy Division.

As noted above, CEJA alleged throughout the proceeding that the LCR RFO should have stated an explicit preference for renewable projects located within the City of Oxnard. This would have necessitated changes to the procurement plan approved by Energy Division. D.13-02-015 established a process for SCE to procure the required LCR resources, based on a procurement plan to be approved by the Energy Division.[40] Ordering Paragraph 4 of D.13-02-015 specified the elements to be included in SCE's LCR RFO, and Ordering Paragraph 5 required SCE to submit a procurement plan to the Energy Division, and to show that

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[37] CEJA/Sierra Club AFR at 9-10.

[38] CEJA/Sierra Club AFR at 9; Gov. Code section 65040.12(e).

[39] Gov. Code 11135; 22 C.C.R. section 98101.

[40] D.14-08-008 at 2-3.

the plan satisfies Ordering Paragraph 4. In compliance with these requirements, the format of SCE's LCR RFO structure was "detailed in SCE's LCR Procurement Plan" and "approved by the Energy Division."[41]

The Energy Division's approval of SCE's LCR procurement plan confirmed that SCE's LCR RFO format and documents – including the participant instructions where any preference for specific resource types or locations would be specified – complied with D.13-02-015. NRG argued that the Commission should reject CEJA's collateral attack on the Energy Division's approval of SCE's procurement plan and the LCR RFO format and documentation described therein, consistent with prior Commission decisions.[42]

CEJA attempted to justify its collateral attack by arguing that this Application proceeding was CEJA's "first and only opportunity to challenge the adequacy of SCE's procurement plan."[43] In response to CEJA's arguments, the Decision concluded that:

> This proceeding appropriately considers whether SCE followed its procurement plan, not whether the plan itself was adequate. As discussed herein, pursuant to D.13-12-015 [sic], Energy Division approved SCE's procurement plan which included procurement for the Moorpark sub-area in September 2014. If CEJA or another party contended that the *process* authorized in D.13-02-015 for review of SCE's procurement plan was unlawful, they could have filed an application for rehearing of that decision on this point.[44]

In their Application for Rehearing, CEJA/Sierra Club once again challenge the legality of the process for Energy Division to approve SCE's procurement plan.[45] This is another

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[41] Exh. SCE-1 (Bryson) at 11:5-6; D.14-08-008 at 3.

[42] *See* D.14-08-008 at Finding of Fact 5 ("It is the function of the Energy Division to determine if the SDG&E procurement plans are in compliance with D.14-03-004."); D. 15-05-051 at 5-6.

[43] Decision at 18.

[44] *Id.* (emphasis added).

[45] CEJA/Sierra Club AFR at 10-13.

impermissible collateral attack on D.13-02-15. As CEJA/Sierra Club acknowledge, D.13-02-015 specified that Energy Division would review and approve SCE's procurement plan for consistency with the requirements of D.13-02-015. CEJA/Sierra Club complain that they were deprived of the opportunity to review and comment on the procurement plan before it was approved, but they were aware of the process adopted in D.13-02-015 and could have challenged the legality of the process in an application for rehearing of D.13-02-015. Having failed to do so, they are barred from challenging the legality of the process for approval of the procurement plan at this juncture.[46]

CEJA/Sierra Club's objection is also misplaced because they were not denied any right or opportunity to object to selection of the Puente Contract based on environmental justice considerations. The Decision fully considered CEJA/Sierra Club's arguments in opposition to the LCR RFO process and the Puente Contract. In particular, CEJA's claims regarding environmental justice considerations were fully vetted and considered. Ultimately, the Decision found that CEJA's environmental justice arguments did not warrant invalidation of the LCR RFO or rejection of the Puente Contract. CEJA/Sierra Club may disagree with that conclusion, but they cannot credibly assert that they were denied the right to raise environmental justice objections to approval of the Puente Contract.

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[46] The case cited by CEJA/Sierra Club does not support their argument. CEJA/Sierra Club cite *So. Cal. Edison Co. v. Pub. Util. Comm'n.,* where the Court rejected a claim that the Commission had unlawfully deleted authority to the CEC. 227 Cal.App.4th 172 at 195-96. In D.13-02-015, the Commission authorized the Energy Division to review and approve utilities' procurement plans for consistency with the Commission's decisions. This was not a "total abdication of authority" as CEJA/Sierra Club allege. The Commission established the requirements for SCE's procurement plan in D.13-02-015 and prior decisions, and did not unlawfully delete a general policymaking power. The process adopted in D.13-02-015 is consistent with the standards articulated by the court in the case cited above.

E. CEQA Does Not Require the Commission to Conduct an Environmental Review of the Puente Project, or Wait for the CEC's Review.

CBD argues that the Decision violated CEQA because the Commission failed to conduct an environmental review of the Puente Project.[47] CEJA/Sierra Club argue that the Commission is a "responsible agency" for the Puente Project under CEQA, and therefore is required by CEQA to "await completion of CEQA review by the lead agency, which is the CEC" before approving the Puente Contract.[48] The City purports to "join" CEJA/Sierra Club's arguments, but with the modified position that "the Commission is the first agency to exercise discretion over the Puente project," and "is therefore the lead agency under CEQA and required to conduct environmental review of the Puente project."[49]

All of these arguments rely on an incorrect legal premise – namely that the Commission's approval of the Puente Contract is a "project" as defined by CEQA. This is simply wrong, as confirmed by longstanding Commission precedent holding that Commission approval of a power purchase agreement is not a project for purposes of CEQA. Because approval of the Puente Contract is not a CEQA "project," all of the Filing Parties' CEQA arguments are without merit, as explained below.

1. The Commission's approval of the Puente Contract is not a "project" that triggers environmental review under CEQA.

CEQA applies only to discretionary "projects" proposed to be carried out or approved by public agencies.[50] CEQA defines a "project" as an activity which may cause either a direct physical change in the environment, or a reasonably foreseeable indirect physical change in the environment, *and which is any of the following*:

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[47] CBD AFR at 4-16.

[48] CEJA/Sierra Club AFR at 14.

[49] City AFR at 1.

[50] California Public Resources Code ("PR Code") section 21080(a).

(a) an activity directly undertaken by any public agency;

(b) an activity undertaken by a person which is supported, in whole or in part, through contracts, grants, subsidies, loans, or other forms of assistance from one or more public agencies; or

(c) an activity that involves the issuance to a person of a lease, permit, license, certificate, or other entitlement for use by one or more public agencies.[51]

It is well established that the Commission's approval of a power purchase agreement executed by a Commission-regulated utility is not a "project" for purposes of CEQA. The Commission has reached this conclusion consistently for decades. In 1986, the Commission concluded that CEQA review was not required for approval of the request of Pacific Gas and Electric Company ("PG&E") for cost recovery of a power purchase agreement for the output of the Dinkey Creek Hydroelectric Project, and explained that:

> The present application does not involve the granting of a lease, permit, license, certificate or other entitlement for use. PG&E is requesting approval of a power purchase agreement. PG&E is neither the builder nor the owner of the proposed Dinkey Creek Project. PG&E seeks only to obtain assurance that it will recover through its rates the payments made under the agreement. Such a ratemaking order is not a "project" under CEQA. This issue has been raised before the Commission and the California Supreme Court on several occasions. All Commission orders concluding that CEQA does not apply to a ratemaking proceeding have been upheld. (E.g., *Samuel C. Palmer, III v. Public Utilities Commission* SF# 23980, writ denied 5/10/79.)[52]

In subsequent decisions, the Commission has repeatedly confirmed that CEQA does not require the Commission to conduct an environmental review when reviewing and approving utility power purchase agreements.[53] The Commission recently again confirmed that

[51] PR Code section 21065.

[52] D.86-10-044, 1986 Cal PUC LEXIS 642, 22 CPUC2d 114.

[53] *See e.g.*, Resolution E-4686 (confirming that review of "the CA Flats PPA is not a `project' pursuant to CEQA"); Resolution E-4522 ("The Commission reiterates that while it acknowledges that environmental issues with Rio Mesa 2 have the potential to pose significant risks, the Commission will not pre-judge the projects in light of these issues. The Commission also notes that environmental permitting for the PPAs is the jurisdiction of the California Energy Commission."); Resolution E-4467 ("Commission review of a

Commission approval of power purchase agreements does not require environmental review under CEQA, and rejected many of the same arguments that are now repeated in the Applications for Rehearing. In D.15-05-051, the Commission approved a power purchase tolling agreement ("PPTA") executed by San Diego Gas and Electric Company ("SDG&E") for a new gas-fired power plant, and rejected CBD' s argument that CEQA review was required:

> To the contrary, CEQA Guidelines, long-standing case law, and Commission precedent all make clear that Commission review of purchase power contracts does not trigger CEQA. A contract for purchase power by a regulated entity is not a "project" pursuant to CEQA. CEQA defines a "project" as "[a]ctivities involving the issuance to a person of a lease, permit, license, certificate, or other entitlement for use by one or more public agencies." (Public Resources Code § 21065.) Commission approval of a purchase power contract does not confer a lease, permit, license, certificate, or any other entitlement on the seller. Rather, it is an assurance that the utility will recover through its rates the costs that it incurs under the contract. It is well-settled that "[s]uch a ratemaking order is not `project' under CEQA. All Commission orders concluding that CEQA does not apply to a ratemaking proceeding have been upheld. (E.g., Samuel C. Palmer, III v. Public Utilities Commission SF# 23980, writ denied 5/10/79.)" (D.86-10-044 at 16-17, 1986 Cal. PUC LEXIS 642, 16-17 (Cal. PUC 1986).)
>
> Likewise, the Commission is not a "responsible agency" under CEQA when it approves purchase power contracts. A "responsible agency" is defined as a public agency other than the lead agency which has discretionary approval power over the project. (Public Resources Code § 21069.) While the Commission has considerable discretion over whether to approve a purchase power contract, it does not have power to approve or deny the underlying generation project. The project underlying the purchase power

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PPA is not review of a "project," but a review of the costs SDG&E' s ratepayers will incur pursuant to the proposed PPA. Further, any project, as defined by CEQA, is subject to all applicable environmental laws."); Resolution E-4439 ("As previously noted by this Commission, the Commission' s review of PPAs is confined to approval of costs pursuant to a PPA. Further, Commission approval of the PPA does not exempt the project from compliance with all applicable environmental laws nor does it limit the review of project alternatives should future environmental reviews of the development projects require such analysis.").

> contract could proceed regardless of the Commission's decision. (Id. at 16-18.)[54]

CBD argues that the conclusions in D.15-05-051 are wrong,[55] but the Commission already considered and rejected CBD's objections in its decision denying rehearing of D.15-05-051. In D.15-11-024, the Commission rejected CBD's arguments and elaborated as follows:

> Despite CBD's protests, we have adequately explained the reasons that PPTA approvals are not CEQA projects. (See Decision, at pp. 29-31.) Pursuant to CEQA, a CEQA project must be one of the following:
>
> (a) An activity undertaken by a public agency.
>
> (b) An activity undertaken by a person which is supported… from one or more public agencies. (c) An activity that involves the issuance to a person of a lease, permit, license, certificate, or other entitlement for use by one or more public agencies.
>
> (Pub. Resources Code, § 21065.)
>
> SDG&E's application is not a CEQA project because our consideration of SDG&E's application for authorization to enter into the Carlsbad PPTA does not fit within any of these categories. Our PPTA proceedings are utility applications for authority to enter into agreements with power generators to purchase electricity. In PPTA proceedings, we evaluate the proposed contracts for consistency with Commission requirements, and decide on whether to authorize the utilities to enter into the contracts and recover costs of the PPTA in rates. These proceedings are largely in the nature of reasonableness reviews in advance of the utility's commitment. (See § 454.5(d)(2).) As such, we do not issue "a lease, permit, license, certificate, or other entitlement for use," to the utility when approving a PPTA, and a PPTA application is not a CEQA project.
>
> Moreover, as we have explained, in PPTA applications, the utility, and not the project proponent, is the applicant. Here, we do not have jurisdiction over Carlsbad Energy Center, the underlying project proponent, and do not approve or disapprove the generation project itself. (See Decision, at p. 30.) It is Carlsbad Energy

[54] D.15-05-051 at 29-30 (footnotes omitted).

[55] CBD AFR at 16-21.

Center which is actually proposing to construct the plant, and its application to construct the Carlsbad Project has been considered by the California Energy Commission ("CEC") in separate proceedings outside of this agency.

In its argument, CBD does not acknowledge or rebut our explanation that PPTA applications do not fit within the CEQA definition of project. Instead, CBD focuses on other required elements for triggering CEQA review requirements, such as whether the project is discretionary (Pub. Resources Code, § 21080 (a)), and whether it may cause a physical change in the environment (Pub. Resources Code, § 21065). (CBD App. Rehg., at p. 2.) This argument is misplaced, because regardless of whether the PPTA review is discretionary, or has potential to impact the environment, SDG&E's PPTA application does not fit within the definition of a CEQA project pursuant to the Public Resources Code.

In quoting a portion of Public Resources Code section 21065, CBD omits the portion quoted above that specifies that only certain types of actions constitute CEQA projects. As a result, CBD fails to counter our conclusion that the PPTA application does not fit within the CEQA definition because it is not issuance of "a lease, permit, license, certificate, or other entitlement for use." (Pub. Resources Code, § 21065.)

Similarly, CBD's objection that our explanation of why SDG&E's application is not a CEQA project is not "legally cognizable" (CBD App. Rehg., at p. 14) is mistaken. CBD claims that our "entire argument" that the Carlsbad PPTA is not a project "is based entirely upon a 1979 denial of a writ and a 1986 Commission decision that cites only to the 1979 denial." (Ibid.) CBD goes on to argue that the writ denial is not citable authority. (Id., at 14-18.) To the contrary, our reference to the 1979 writ denial, *Palmer v. Public Utilities Commission*, SF# 23980, is not relied upon as precedent. Rather, *Palmer* is only noted in a quote from one case in a long line of Commission decisions and Energy Division resolutions concluding that PPTA applications, and ratemaking applications generally, are not CEQA projects. It is these decisions that constitute the well-established precedent. Thus, the basis for our conclusion that PPTA applications are not CEQA projects is based on the CEQA statutory language, as explained above, and that conclusion is strongly supported by Commission precedent.

CBD raises a number of other claims regarding how and when we must conduct the Carlsbad PPTA CEQA review. (CBD App. Rehg., at pp. 10-13.) Again, all of these arguments fail because SDG&E's Carlsbad PPTA application is not a CEQA project, and

> therefore, none of the CEQA review requirements are applicable. (See Decision, at pp. 30-31, fn 23.)[56]

The same conclusions apply here. The Commission's approval of the Puente Contract authorized SCE to meet its LCR need through the Puente Contract and recover costs incurred under the Puente Contract through rates. SCE is not the builder or the owner of the Puente Project. The Puente Project will be built by NECO, an entity that is not subject to the Commission's general jurisdiction. The Commission does not have authority to approve, deny, or condition construction of a power plant by a non-utility independent power producer such as NECO. The CEC, not the Commission, is the state agency with discretionary (and exclusive) authority over the construction of the Puente Project, a thermal power plant with a capacity in excess of 50 MW. The Warren-Alquist Act, codified in the PR Code, specifies that the CEC has "exclusive power" to certify all such thermal power plants, and confirms that the issuance of a CEC license "shall be in lieu of any permit, certificate, or similar document required by any state, local or regional agency."[57] Commission approval of the Puente Contract thus does not allow construction of the Puente Project to proceed, and construction could proceed without Commission approval if the CEC authorizes construction. For all of the reasons explained in the Commission's prior decisions, approval of the Puente Contract is not a project for purposes of CEQA.

Finally, even if the Commission's approval of the Puente Contract were technically a "project," which it is not for the reasons discussed above, CEQA provides an exemption for actions undertaken by public agencies relating to any thermal power plant that will be licensed by the CEC. Pursuant to PR Code section 21080(b)(6), CEQA does not apply to:

> Actions undertaken by a public agency relating to any thermal powerplant site or facility, including the expenditure, obligation, or

[56] D.15-11-024 at 2-4 (footnotes omitted).

[57] PR Code section 25500.

> encumbrance of funds by a public agency for planning, engineering, or design purposes, or for the conditional sale or purchase of equipment, fuel, water (except groundwater), steam, or power for a thermal powerplant, if the powerplant site and related facility will be the subject of an environmental impact report, negative declaration, or other document, prepared pursuant to a regulatory program certified pursuant to Section 21080.5, which will be prepared by the State Energy Resources Conservation and Development Commission, by the Public Utilities Commission, or by the city or county in which the powerplant and related facility would be located if the environmental impact report, negative declaration, or document includes the environmental impact, if any, of the action described in this paragraph.[58]

The CEC is the "State Energy Resources Conservation and Development Commission" referenced in the statute, and its thermal power plant siting and environmental review process is a certified regulatory program pursuant to PR Code section 21080.5. The CEC's certified regulatory program entails a full environmental review of potential project impacts and imposes requirements necessary to ensure that all potential environmental impacts are mitigated to below significant levels. This further demonstrates that the Filing Parties' CEQA arguments are without merit.

2. The Commission is not a CEQA "responsible agency" for the Puente Project.

CEJA/Sierra Club argue that the Commission is a "responsible agency" for the Puente Project under CEQA, and therefore is required by CEQA to "await completion of CEQA review by the lead agency, which is the CEC" before approving the Puente Contract.[59] As explained above, the Commission has confirmed that it is not a "responsible agency" under CEQA when it approves purchase power contracts. A "responsible agency" is defined as a public agency other than the lead agency which has discretionary approval power over the project.[60] As the

[58] *See also* CEQA Guidelines, 14 Cal. Code Regs. section 15271.

[59] CEJA/Sierra Club AFR at 14.

[60] PR Code section 21069.

Commission confirmed: "While the Commission has considerable discretion over whether to approve a purchase power contract, it does not have power to approve or deny the underlying generation project."[61]

As it has done in the past, CBD raises a number of other claims regarding when and how the Commission must conduct an environmental review of the Puente Project, or wait for completion of the CEC's environmental review,[62] but all of CBD's arguments fail because approval of the Puente Contract is not a CEQA project.

3. Approval of the Puente Contract does not transform the Commission into the CEQA "lead agency" for the Puente Project.

The City purports to "join" CEJA/Sierra Club's CEQA argument with the modification that "the Commission is the first agency to exercise discretion over the Puente project," and "is therefore the lead agency under CEQA and required to conduct environmental review of the Puente project."[63] The City has not met the requirements of PU Code section 1732. Further, the City's arguments in its briefs in this proceeding are without merit, as explained below.

a. The City has not met the requirements for a legally adequate application for rehearing.

The City does not explain how the Decision contains legal error, but instead merely drops a footnote with a citation to its opening and reply briefs. The City's purported "Application for Rehearing" does not comply with the requirements of PU Code section 1732, which requires applications for rehearing to "set forth specifically the ground or grounds on which the applicant considers the decision or order to be unlawful or erroneous." The City's filing also fails to comply with Rule 16.1(c), which states that "the purpose of an application for rehearing is to

[61] D.15-05-051 at 29-30.

[62] CBD AFR at 5-16.

[63] City AFR at 1.

alert the Commission to legal error." The City fails to identify and explain any legal errors with the Decision. The City's citation, without explanation, of arguments it made in briefs in this proceeding is insufficient to meet the requirements of PU Code section 1732.[64]

b. The City's briefs in the proceeding do not demonstrate legal error in the Decision.

In its opening brief, the City wrongly argued that the Commission must act as the CEQA lead agency for the Puente Project because approval of the Puente Contract would foreclose alternatives or mitigation measures that would ordinarily be part of CEQA review of the Puente Project.[65] As explained in NRG's reply brief, this is not true, as nothing in NECO's testimony, or its application for certification for the Puente Project, could dictate or constrain the CEC's authority to consider alternatives or require mitigation.[66]

The City also wrongly alleged that NECO's witness, Ms. Gleiter, testified that "contract approval will provide significant financial momentum to the Puente project," and "makes it far more likely that the CEC will approve its project."[67] The City's brief blatantly misrepresented Ms. Gleiter's testimony. In reality, when Ms. Gleiter was asked to confirm that "NRG has determined that PUC approval here makes it more likely that it will receive approval of this project from the CEC", Ms. Gleiter responded: "No, that is definitely not true."[68]

The City's CEQA argument also relied on language in *Save Tara v. City of West Hollywood* stating that "before conducting CEQA review, agencies must not `take any action' that significantly furthers a project `in a manner that forecloses alternatives or mitigation

[64] D.16-05-053 at 16.

[65] City Opening Brief at 17-18.

[66] NRG Reply Brief at 23-30.

[67] City Opening Brief at 18.

[68] Reporter's Transcript, Volume 2 (NRG/Gleiter) at 340:16-21.

measures that would ordinarily be part of CEQA review of that public project.' "[69] However, this principle does not apply because Commission approval of the Puente Contract does not, and could not, constrain the CEC's authority to analyze alternatives or require mitigation in compliance with CEQA.

The *Save Tara* holding does not apply here. In *Save Tara,* the Court addressed "the question of whether and under what circumstances an agency's agreement allowing private development, conditioned on future compliance with CEQA, constitutes approval of the project within the meaning of sections 21100 and 21151" of CEQA.[70] The case involved an agreement entered into by the City of West Hollywood conveying to a developer an option to purchase certain city-owned real estate for use to construct a housing development, with an additional commitment by the city (not conditioned on CEQA compliance) to contribute toward development costs. The city's obligation to convey the property was conditioned on all applicable requirements of CEQA having been satisfied. The petitioners sought a decision holding that the city was required to prepare an environmental impact report for the housing development project *before* it agreed to convey the property to the developer. The Court held that: "A CEQA compliance condition can be a legitimate ingredient in a preliminary public-private agreement for exploration of a proposed project, but if the agreement, viewed in light of all the surrounding circumstances, commits the public agency as a practical matter to the project, the simple insertion of a CEQA compliance condition will not save the agreement from being considered an approval requiring prior environmental review."[71]

Here the Commission is not conveying any property to NECO, or agreeing to explore or move forward with a public-private partnership with NECO. The Commission also is not

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[69] *Save Tara v. City of West Hollywood,* 45 Cal. 4th 116, 138 (2008)

[70] *Id.* at 121.

[71] *Id.* at 132.

granting approval for construction of the Puente Project to proceed. Commission approval of the Puente Contract also does not, and could not, commit the CEC to approve the Puente Project or limit the scope of the CEC's environmental review of the Puente Project. Although the City and other parties insisted on using this proceeding to object to the Puente Project on environmental grounds, the only action that the applicant requested is for the Commission to approve the Puente Contract and authorize rate recovery. Consistent with the Commission's long-standing and recently affirmed precedent on utility power purchase agreements (discussed above), approval of the Puente Contract is not a "project" for purposes of CEQA. It follows that the Commission is not the CEQA lead agency for the Puente Project.

4. The Commission was not required to consider CEQA arguments that have been rejected repeatedly in prior Commission decisions.

CBD alleges that the Decision erred by not addressing CBD's argument that CEQA requires the Commission to conduct an environmental review, but CBD has not identified any legal error.[72] As explained in detail above, the Commission has consistently held that its review and approval of a utility power purchase contract is not a "project" for purposes of CEQA. The issue was raised and addressed in several recent Commission decisions, including in direct response to the same arguments that CBD repeats in its Application for Rehearing. The Commission was not required to revisit its well established precedent on CEQA simply because CBD repeated the same flawed legal arguments that have already been addressed and rejected in prior Commission decisions.

PU Code section 1705 also does not require the Commission to address CBD's baseless CEQA argument. PU Code section 1705 provides that a Commission decision "shall contain, separately stated, findings of fact and conclusions of law by the commission on all issues material to the order or decision . . ." It is within the Commission's discretion to determine what

[72] CBD AFR at 16.

factors are material to its decision based on the issues before it.[73] PU Code section 1705 does not require the Commission to make express legal and factual findings as to each and every issue or sub-issue raised by a party to a proceeding.[74]

Further, the Scoping Memo did not include the question of whether CEQA review is required. The Scoping Memo recognized that the CEC is the lead agency under CEQA and the agency with jurisdiction to conduct the environmental review of the Puente Project. The Scoping Memo only included the question of whether the Commission should defer its approval to wait for CEC approval.[75] The Decision addressed that topic and included findings and conclusions material to the Commission's decision not to delay approval to await the outcome of the CEC's review.[76]

F. Approval of the Puente Contract Did Not Violate the Loading Order.

CBD argues that the Commission violated PU Code section 454.5 and the Loading Order because the Decision "does not address preferred resources in any way; there are no findings of fact or conclusions of law regarding compliance with section 454.5 or the Commission's duties to comply with the preferred resources loading order and to protect the environment."[77] CBD argues that the Commission failed to address CBD's sponsored testimony, which argued that preferred resources are available for procurement in the Moorpark sub-area.[78] CBD also argues that the results of the LCR RFO for Moorpark violate the Loading Order due to the high percentage of gas-fired generation.[79]

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[73] *Clean Energy Fuels,* 227 Cal. App. 4th at 659.

[74] D.16-05-053 at 6.

[75] Decision at 7-8.

[76] *Id.* at 19-22.

[77] CBD AFR at 2.

[78] CBD AFR at 3-4, 25-26.

[79] CBD AFR at 21-25.

CBD's arguments are without merit. The Decision cites SCE's testimony confirming that "it was not possible to procure the required minimum level of incremental capacity using only preferred resources," and notes that "SCE contends that it demonstrated that a gas-fired project must be part of the Moorpark reliability solution, and proved that the Puente Contract was the superior gas-fired offer."[80] These statements are supported by the record. SCE solicited offers from all categories of resources, including energy efficiency, demand response, renewable resources, combined heat and power resources, distributed generation, energy storage, and gas-fired generation.[81] SCE's testimony confirms that "[a]ll resource types competed for the authorized 215 to 290 MW in the Moorpark sub-area, with no minimum or maximum MW requirements for Preferred Resources."[82] SCE's testimony further explains that: "A combination of Preferred Resources and GFG will be needed to resolve the reliability issues in the Moorpark sub-area."[83] SCE's testimony showed that SCE selected the Puente Contract because it was "the most cost effective GFG offer available to meet the minimum total" required procurement of 215 MW.[84] SCE's testimony explained that the selected contracts were the "best combination of offers" and "allowed SCE to select cost-competitive Preferred Resources offers."[85] The Independent Evaluator confirmed that the selected contracts are the best resources available from a competitive solicitation.[86]

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80 Decision at 23, citing Exh. SCE-2, Appendix D at D-42.

81 Exh. SCE-1 (Cushnie) at 1:8-12.

82 Exh. SCE-1 (Cushnie) at 7:15-16.

83 Exh. SCE-1 (Cushnie) at 7:16-18.

84 Exh. SCE-1 (Singh) at 45:18 through 46:2, 9-10.

85 Exh. SCE-1 (Singh) at 46:7-9.

86 Exh. SCE-2, Appendix D (Independent Evaluator Report) at 39.

The Decision also found that selection of the Puente Contract was consistent with the Commission's findings in D.13-02-015 that gas-fired resources at the current OTC sites are "certain" to meet the LCR need, explaining:

> D.13-02-015 made several Findings of Fact which are relevant to our independent analysis of the Puente Project contract. Finding of Fact 26 stated: "Gas-fired resources at the current OTC sites are certain to meet the ISO's criteria for meeting LCR needs. Other resources can also meet LCR needs but may not be effective in doing so." Finding of Fact 38 states: "The ISO has shown that there is a need for in-area generation with operational characteristics similar to retiring OTC plants in the Moorpark sub-area of the Big Creek/Ventura local area." Finding of Fact 39 states: "The most likely locations for [sic] to meet LCR needs in the Moorpark sub-area are the sites of the current OTC plants."[87]

The Decision also considered the CAISO's testimony, which showed that the Puente Contract and other procured resources will help maintain reliability. The Decision agreed with the CAISO "that the Puente Project is necessary to meet identified local reliability need in the Moorpark sub-area."[88] After weighing the evidence, the Decision concluded that the LCR RFO process was reasonable and complied with D.13-02-015, and found that the Puente Project "is expected to provide necessary grid reliability benefits at a reasonable cost to ratepayers."[89]

These findings do not violate PU Code section 454.5 or the Loading Order. By its terms, PU Code section 454.5, in its entirety, applies to utility procurement plans, which were not at issue in this proceeding. The Loading Order is established through Commission order, but as the Commission recently confirmed, "all relevant authority acknowledges that the Loading Order requirements must be balanced with the State's reliability and economic needs."[90] "As both the Legislature and the Commission have repeatedly emphasized, the need for reliability is

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[87] Decision at 24-25.

[88] *Id.* at 25.

[89] *Id.* at 26.

[90] D.16-05-053 at 9, citing D.14-03-004 at 13.

paramount in the utility's procurement efforts."[91] In this proceeding, SCE demonstrated that it solicited offers for all resource types, including preferred resources that rank high in the loading order. SCE also demonstrated that "with the exception of energy storage ("ES"), SCE selected every Preferred Resource final offer it received in the Moorpark sub-area, and still had to select a large [gas fired generation ("GFG")] project to meet the minimum procurement authorization of 215 MW."[92] Based on the record in this proceeding, and the findings in D.13-02-015 that existing OTC sites are the ideal location for new LCR capacity, the Decision's approval of the Puente Contract was reasonable and did not constitute legal error.

The Decision also was not required to give weight to CBD's sponsored testimony asserting that the Southern California Regional Energy Network has identified 200 MW of preferred resources in the Moorpark sub-area. As stated above, SCE explained that it selected every preferred resource final offer it received (with the exception of some ES), and still had to select a gas-fired resource to meet the minimum procurement authorization of 215 MW.[93] CBD has not shown that the resources cited in its testimony were bid into the LCR RFO, or otherwise available to SCE for contracting.

G. The Decision Did Not Rely on Inadmissible Hearsay.

CEJA/Sierra Club argue that the Commission incorrectly relied on "hearsay" in approving the Puente Contract.[94] They cite SCE's testimony that "qualitative factors reinforced SCE's quantitative assessment that the NRG Energy Center was the best option to meet the LCR

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[91] *Id.* at 9; D.14-03-004 at 13 ("California law repeatedly emphasizes the importance of maintaining the reliability of the electric grid."), Conclusion of Law 37 ("It is prudent to promote preferred resources to the greatest extent feasible, subject to ensuring a continued high level of reliability."); PU Code section 334 ("Reliable electric service is of paramount importance to the safety, health and comfort of California.").

[92] Exh. SCE-7 (Cushnie) at 1:20 through 2:1.

[93] Exh. SCE-7 (Cushnie) at 1:20 through 2:2.

[94] CEJA/Sierra Club AFR at 15-17.

need."[95] CEJA/Sierra Club point to the restructuring of the Puente Contract as a resource adequacy contract to address debt equivalence impacts, and argue that this demonstrates that "the quantitative analysis resulted in an offer SCE could not accept."[96] CEJA/Sierra Club then repeat CEJA's argument presented in the proceeding that SCE's selection of the Puente Contract was inappropriately based on "qualitative" assessments regarding the risk of resource shortages due to the possible retirement of existing non-OTC peaking resources owned by NRG South.[97]

The Decision properly rejected CEJA/Sierra Club's argument, and found that:

> As SCE explains in its reply brief at 11, the qualitative factors reinforced SCE's quantitative assessment that the NRG Energy Center was the best option to meet the LCR need. SCE's assessment combining qualitative and quantitative factors is consistent with its procurement plan. The outcome of SCE's RFO was found by the Independent Evaluator to be the best resource available from the RFO and was found by the CAISO to meet the LCR needs of the Moorpark sub-area.[98]

The Decision's findings are supported by the record. SCE's testimony explained the quantitative valuation process that was used to select the winning contracts.[99] The Independent Evaluator's report explained that: "The quantitative analysis focused on net market value – namely, the value of a resource's energy, ancillary services, and capacity benefits (based on SCE's forecast of future power and fuel prices) minus fixed and variable offer-related costs"; and "Fundamentally, this was the same across all resource types."[100] SCE's testimony showed that

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95 CEJA/Sierra Club AFR at 15, citing Decision at 25-26. The Decision and SCE's testimony sometimes refer to the Puente Project as the NRG Energy Center.

96 CEJA/Sierra Club AFR at 16.

97 CEJA/Sierra Club AFR at 11-20.

98 Decision at 25-26, Finding of Fact 9 ("The NRG Puente Project contract's economics and general terms and conditions represent the best resource available from the RFO."), and Finding of Fact 10 ("SCE's assessment combining qualitative and quantitative factors in evaluating the NRG Puente Project is consistent with its procurement plan.").

99 Exh. SCE-1 (Singh) at 30-49 and 47:12-19.

100 Exh. SCE-2, Appendix D (Independent Evaluator Report) at 5.

SCE selected the Puente Contract because it was "the most cost effective GFG offer available to meet the minimum total" required procurement of 215 MW.[101] Additional qualitative factors may have supported its selection, but the Puente Contract won due to its net market value.

The Independent Evaluator performed an independent, parallel evaluation of the offers and concluded that all of the selected contracts merit Commission approval "because the contracts' economics and their general terms and conditions represented the best resources available from a competitive solicitation."[102]

Finally, SCE's debt equivalence analysis, which caused SCE to structure the Puente Contract as a resource adequacy contract rather than a tolling agreement, did not alter the conclusion that the Puente Contract offered the best value.[103]

H. Substantial Evidence Supports the Decision's Finding that SCE's LCR RFO Process Complied With Commission Requirements.

CBD argues that SCE impermissibly solicited offers for resources to be operational before 2021,[104] but CBD has not shown how this constitutes legal error in the Decision. SCE's procurement plan, which was approved by the Energy Division, stated that SCE would be soliciting offers in the LCR RFO that would be online as early as 2015 in the Goleta area. This was consistent with D.13-02-015, which did not prohibit resources coming online before 2021 but merely required that resources be online *by* 2021. Further, CBD's argument does not apply to the Puente Contract, which provides for the Puente Project to commence deliveries in 2020, shortly before the 2021 deadline.

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[101] Exh. SCE-1 (Singh) at 45:18 through 46:2, 9-10.

[102] Exh. SCE-2, Appendix D (Independent Evaluator Report) at 39.

[103] Exh. SCE-1 (Singh) at 47-48; Exh. SCE-2, Appendix D (Independent Evaluator Report) at 20-21.

[104] CBD AFR at 26-27.

CBD also argues that the LCR RFO schedule did not allow sufficient time for preferred resources vendors to participate, and alleges that the LCR RFO was "designed to discourage preferred resources" based on security requirements and the lack of a form contract for distributed generation ("DG").[105] These claims are baseless. SCE communicated through the LCR RFO documents and at the bidder's conference that it was willing to work with bidders to customize contracts.[106] Offers were submitted for DG and SCE ultimately signed customized DG contracts with SunPower (parent company of Solar Star California), which were approved in the Decision.[107]

CBD's claim that "the requirement of security prejudiced the RFO against preferred resources,"[108] is equally unsubstantiated. Although SCE required some level of development security for all resources to help ensure the resources showed up to maintain the reliability of the system, SCE had different development security requirements for different products.[109] SCE noted that the development security amount for preferred resources was significantly lower than that required for entities who signed contracts for gas-fired generation.[110] Lower security requirements would tend to encourage, not discourage, participation by preferred resources.

I. The Commission Was Not Required to Reconsider the Need Determination Adopted in D.13-02-015.

CBD argues that the Commission erred by not reviewing the validity of the need determination adopted in D.13-02-015 based on changed circumstances and CBD's questioning of whether SCE's McGrath peaking facility was included in the CAISO modeling analysis that

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105 CBD AFR at 27-29.

106 SCE Reply Brief at 29.

107 SCE Reply Brief at 29.

108 CBD AFR at 29-30.

109 SCE Reply Brief at 29-30.

110 SCE Reply Brief at 29-30.

was the basis for the D.13-02-015 need determination.[111] CBD also argues that the Decision wrongly concluded that the need determination depended upon the retirement of Mandalay Units 1 and 2 and Ormond Beach OTC units.[112] These arguments are without merit.

First, the Commission is not required to reevaluate the need determination adopted in an LTPP decision when it approves contracts that were executed to fill the approved need. The Commission has confirmed that its established procurement and planning process is to determine utility local capacity requirements need in general procurement decisions, such as D.13-02-015, and not to reconsider those need determinations when approving contracts proposed to fill the approved need, "absent an unforeseen emergency."[113] This reflects the Commission's preference that a contract review proceeding "should not reconsider the Commission's original need determination where one has been made, for the sake of utility predictability and an orderly government process in which settled issues are not rehashed endlessly."[114] Decisions concerning how to organize Commission proceedings are entirely within the Commission's discretion.[115] It was not legal error for the Commission to follow its preferred practice of not reconsidering a need determination adopted in a prior LTPP decision.

Second, the existence of the McGrath peaker does not eliminate the need determination adopted in D.13-02-015. As SCE testified, the McGrath peaker was modeled in the 2014-2015 CAISO Transmission Plan.[116] The CAISO also testified that: "The results of SCE's 2013 Moorpark RFO are consistent with the CAISO's planning assumptions in the 2014-2015

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[111] CBD AFR at 30-32.

[112] CBD AFR at 35-36.

[113] D.15-11-024 at 10.

[114] D.06-11-048 at 10.

[115] *Pacific Telephone and Telegraph Co. v. Public Utilities Comm*. (1965) 62 Cal. 2nd 634, 647.

[116] Exh. SCE-7 (Chinn) at 11:5-11.

transmission plan"; and "The resources selected in the RFO meet the minimum procurement requirements set forth in the Commission's Track 1 long-term procurement plan decisions, and they are effective and necessary to meet long-term reliability needs as demonstrated by the CAISO's analysis."[117] Therefore, no adjustment to the need authorization was necessary.

Finally, CBD's allegation that the Commission should reconsider the need determination based on allegations that some OTC units may not actually retire by their OTC compliance deadline is also without merit. To prepare the studies underlying the D.13-02-015 need determination, the CAISO and the Commission assumed that all of the OTC capacity in the Moorpark sub-area would retire at the end of 2020, which is the deadline for those units to comply with the State Water Resources Control Board ("SWRCB") policy on the use of OTC. D.13-02-015 acknowledged that some OTC plant owners had preserved a so-called "Track 2" compliance path, which would allow their units to comply with the OTC policy and continue operating, stating: "We are aware of some efforts by specific OTC plant owners to comply with one of the SWRCB tracks to avoid retirement."[118] Ultimately, however, the Commission concluded that: "At this time, it is reasonable to accept as a fact that, based on information available today, OTC plants will close as per the SWRCB schedule;" and "It is reasonable to assume that the OTC plants in the SCE territory required to comply with SWRCB regulations will comply through retirement or repowering consistent with the SWRCB schedule, for the purpose of LCR forecasting in this proceeding."[119] The Decision appropriately and accurately referenced these factual findings in D.13-02-015, stating: "The need determination of the

[117] Exh. CAISO-1 (Sparks) at 4:7-12.

[118] D.13-02-015 at 42.

[119] *Id.* at 42 and Finding of Fact 10.

Moorpark sub-area in D.13-02-015 depended upon the retirement of Mandalay Units 1 and 2 and Ormond Beach once-through-cooling generation units."[120] No legal error occurred.

III. CONCLUSION

As explained above, no Filing Party has demonstrated legal error, or shown that the Decision is unlawful or erroneous. Rehearing is not required or warranted, and the Applications for Rehearing should be denied.

July 18, 2016

Respectfully submitted,

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[120] Decision at 25 and Finding of Fact 13.

EXHIBIT E

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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.	A.14-11-016 (Filed November 26, 2014)

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) RESPONSE TO APPLICATIONS FOR REHEARING OF DECISION 16-05-050

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SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) RESPONSE TO APPLICATIONS FOR REHEARING OF DECISION 16-05-050

TABLE OF CONTENTS

Section	Page

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) RESPONSES TO APPLICATIONS FOR REHEARING OF DECISION 16-05-050

TABLE OF CONTENTS (CONTINUED)

Section	Page

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) RESPONSE TO APPLICATIONS FOR REHEARING OF DECISION 16-05-050

TABLE OF AUTHORITIES

Page

Commission Decisions and Resolutions

Commission Rules of Practice and Procedure

TABLE OF AUTHORITIES

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.	A.14-11-016 (Filed November 26, 2014)

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) RESPONSE TO APPLICATIONS FOR REHEARING OF DECISION 16-05-050

(PUBLIC VERSION)

Pursuant to Rule 16.1(d) of the California Public Utilities Commission's ("Commission") Rules of Practice and Procedure, Southern California Edison Company ("SCE") hereby responds to the Applications for Rehearing ("AFRs") filed by the Center for Biological Diversity ("CBD"), the City of Oxnard[1] ("Oxnard") and California Environmental Justice Alliance/Sierra Club[2] ("CEJA/Sierra Club") of Decision ("D.") 16-05-050, which approved, in part, contracts from SCE's 2013 Local Capacity Requirement ("LCR") Request for Offers ("RFO") for the Moorpark sub-area. Rule 16.1(d) states that "[i]n instances of multiple applications for rehearing the response may be to all such applications, and may be filed 15 days after the last application for rehearing was filed." SCE is responding to all AFRs in its response. Oxnard filed its AFR on July 1, 2016; SCE is appropriately filing its response on July 18, 2016.

1 Oxnard's AFR is limited to it joining CEJA/Sierra Club's AFR, with the exception of Section IV.D. Oxnard AFR at 1. Therefore, when SCE references and responds to CEJA/Sierra Club arguments, with the exception of the arguments made in Section IV.D., it is also responding to Oxnard, even if not mentioned.

2 CEJA/Sierra Club and Oxnard "do[] not contest Commission approval of the energy efficiency and renewable projects approved as part of D.16-05-050." CEJA/Sierra Club AFR at 1. CEJA/Sierra Club and Oxnard limit their AFRs to the Commission's approval of the Puente contract and the Commission's consideration of the procurement process that led to Application ("A.") 14-11-016, whereas, CBD's AFR seems to call into question the approval of the entire RFO process and all approved contracts. CBD AFR at 1-4, 22-36.

I.

INTRODUCTION

Rule 16.1(c) of the Commission's Rules of Practice and Procedure provides, "[t]he purpose of an application for rehearing is to alert the Commission to a legal error, so that the Commission may correct it expeditiously." SCE respectfully requests that the Commission deny the parties' AFRs because they fail to identify any legal error in D.16-05-050.

As prescribed by Rule 16.1, an application for rehearing must identify a "legal error;" it is not sufficient to reiterate evidentiary or policy arguments made throughout the proceeding.[3] "The fact that there is disagreement or contrary evidence on a holding does not indicate any legal error in the Decision."[4] Furthermore, as stated by the Commission in D.14-12-086, "the Commission is not required to address every single issue presented by a party" in a proceeding.[5]

The parties may not be satisfied with D.16-05-050 and its findings and conclusions, but the Commission has the discretion to arrive at its findings in the manner of its own discretion[6] and may weigh evidence and reach a determination using its judgment.[7] Moreover, "[t]here is a strong presumption favoring the validity of a Commission decision."[8] The standard for review of Commission decisions requires that all reasonable doubts be resolved in favor of the Commission's decision.[9] The standard is whether "based on the evidence before the agency, a

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[3] *See* Rule 16.1(c), Commission's Rule of Practice and Procedure; D.13-01-041 at 7 ("The purpose of a rehearing application is not to re-litigate policy determinations.").

[4] *See* D.09-07-024 at 2 (holding that the vast majority of petitioner's arguments for rehearing were improper attempts to relitigate evidentiary issues decided by the Commission).

[5] D.14-12-086 at 3.

[6] *See Pacific Tel. & Tel. Co. v. Pub. Utilities Comm'n*, 62 Cal.2d 634, 647 (1965) (There is a "strong presumption of the correctness of the findings…of the commission, which may choose its own criteria or method of arriving at its decision.").

[7] *SFPP, L.P. v. Pub. Utilities Comm'n*, 217 Cal. App. 4th 784, 794 (2013) ("[i]t is for the agency to weigh the preponderance of conflicting evidence….") (internal quotations and citations omitted); *see also Eden Hospital Dist. v. Belshe*, 65 Cal. App. 4th 908, 915 (1998).

[8] *SFPP*, 217 Cal. App. at 794 (internal quotations and citations omitted); *see also Greyhound Lines, Inc. v. Pub. Utilities Comm'n*, 68 Cal. 2d 406, 410-411 (1968).

[9] *Harris v. City of Costa Mesa*, 25 Cal. App. 4th 963, 969 (1994) ("[T]he reviewing court must resolve reasonable doubts in favor of the administrative findings and decision.") (internal quotations and

reasonable person could not reach the conclusion reached by the agency;" not whether opponents claim that the evidence is insufficient.[10] If the record contains substantial evidence supporting the agency's determination, then the determination must be upheld.[11]

The AFRs filed by CEJA/Sierra Club and CBD do not identify "legal error." Instead, they reiterate and reassert arguments and issues previously raised in this proceeding under the guise of "legal error." For example, starting in its Opening Brief and continuing through its Opening and Reply Comments on Commissioner Peterman's Alternate Decision, CEJA has argued the following: SCE was required to take environmental justice criteria into consideration in its RFO,[12] SCE did not prioritize renewable projects in environmental justice communities in violation of Public Utilities Code § 399.13(a)(7),[13] the Commission failed to conduct Commission review of SCE's procurement plan,[14] the Commission was required to await environmental review of the Puente project before approval pursuant to the California Environmental Quality Act ("CEQA"),[15] and SCE relied on a "hearsay, qualitative factor"[16] in the selection of the Puente contract, and not quantitative and qualitative factors.[17]

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citation omitted); *see also , e.g., Utility Consumers' Action Network v. Pub. Utilities Comm'n*, 187 Cal. App. 4th 688, 696–97 (2010).

10 *Harris*, 25 Cal. App. 4th at 969.

11 *Barthelemy v. Chino Basin Mun. Water Dist*., 38 Cal. App. 4th 1609, 1620 (1995).

12 CEJA Opening Brief at 5-11; CEJA Reply Brief at 1-8; CEJA Reply Comments on ALJ DeAnglis' Proposed Decision ("PD") and Commissioner Florio's Alternate PD at 2-5; CEJA's Opening Comments on Commissioner Peterman's Alternate Decision at 4-6; CEJA's Reply Comments on Commissioner Peterman's Alternate Decision at 4-5.

13 CEJA's Opening Brief at 10-11; CEJA Reply Brief at 5-6; CEJA's Opening Comments on Commissioner Peterman's Alternate Decision at 9-11; CEJA's Reply Comments on Commissioner Peterman's Alternate Decision at 3-4. *See also* CEJA Reply Brief at 5-6; CEJA Opening Comments on ALJ DeAnglis' PD and Commissioner Florio's Alternate PD at 3; CEJA Reply Comments on ALJ DeAnglis' PD and Commissioner Florio's Alternate PD at 2-3.

14 CEJA Opening Brief at 6-7; CEJA's Opening Comments on Commissioner Peterman's Alternate Decision at 11-13.

15 CEJA Opening Brief at 22-25; CEJA Reply Brief at 14-17.

16 CEJA/Sierra Club AFR at 16.

17 CEJA Opening Brief at 11-19; CEJA Reply Brief at 8-13; CEJA Opening Comments on ALJ DeAnglis' PD and Commissioner Florio's Alternate PD at 7-10; CEJA's Opening Comments on Commissioner Peterman's Alternate Decision at 15.

Similarly, the CBD AFR reiterates the exact arguments it has made throughout the proceeding, most notably, that the Commission cannot approve the Puente project without completion of CEQA review,[18] the Commission's approval of the results of the LCR RFO is in violation of the Loading Order,[19] the LCR RFO was biased against Preferred Resources[20] and it has not been demonstrated that 215-290 megawatts ("MW") are needed in the Moorpark sub-area.[21]

Additionally, although CEJA/Sierra Club and Oxnard "do[] not contest Commission approval of the energy efficiency and renewable projects approved as part of D.16-05-050[,]"[22] CBD's AFR calls into question the approval of the entire RFO process and all approved contracts. By not limiting its AFR to the approval of specific contracts, CBD jeopardizes *all* of the contracts approved in D.16-05-050, including all of the Preferred Resource contracts. The Preferred Resource contracts face the most risk because of earlier commercial operation deadlines.[23] This is inconsistent with the premise of CBD's arguments regarding the importance of the Loading Order and Preferred Resources.

Contrary to the parties' assertions, D.16-05-050 is not unlawful or erroneous, and there is a robust record in this proceeding supporting the findings and conclusions in the decision. Furthermore, CBD's AFR seeks to place all of the contracts approved in D.16-05-050 at risk, without basis. Therefore, SCE respectfully requests that the Commission expeditiously deny the parties' AFRs.

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[18] CBD Protest at 13-14. CBD Opening Brief at 16-17; CBD Reply Brief at 2-16.

[19] CBD Protest at 5-6; CBD Opening Brief at 2-7; CBD Opening Comments on ALJ DeAngelis' PD and Commissioner Florio's Alternate PD at 2-4.

[20] CBD Protest at 6-11; CBD Opening Brief at 8-11; CBD Opening Comments on ALJ DeAngelis' PD and Commissioner Florio's Alternate PD at 7-9.

[21] CBD Protest at 11-13. CBD Opening Brief at 11-16; CBD Opening Comments on ALJ DeAngelis' PD and Commissioner Florio's Alternate PD at 9-13.

[22] CEJA/Sierra Club AFR at 1.

[23] Exhibit SCE-1, SCE's Opening Testimony, at 52 (Summary of Energy Efficiency Selected Offers), 53 (Summary of Renewable Distributed Generation Selected Offers).

II.

D.16-05-050 IS NOT UNLAWFUL OR ERRONEOUS

A. D.16-05-050 Does Not Violate the Requirements of the Long Term Procurement Plan Track 1 Decision, the Loading Order or Any Other Law

Many of the claims made by CEJA/Sierra Club and CBD directly question the Commission's interpretation of its own decisions and the Public Utilities Code. Yet, the Commission's interpretation of its own decisions "is entitled to consideration and respect[,]"[24] and its "interpretation of the Public Utilities Code should not be disturbed unless it fails to bear a reasonable relation to statutory purposes and language."[25] As will be explained below, the parties' arguments do not meet the aforementioned standards and their AFRs should be rejected.

1. D.16-05-050's Approval of the Puente Contract is Not Unlawful or Erroneous

The thrust of CEJA/Sierra Club's AFR is that the Commission acted unlawfully by approving the Puente contract because SCE did not address environmental justice issues in the selection of the project.[26] By focusing on one qualitative consideration amongst many factors and analyses that went into the selection of resources through a complicated and unprecedented RFO, CEJA/Sierra Club provide a very narrow and skewed view of the law, SCE's LCR RFO, and the selected offers. To provide some perspective, SCE submitted its LCR Procurement Plan to Energy Division ("ED") on July 15, 2013, launched the LCR RFO on September 12, 2013, received final offers on September 4, 2014, communicated offer awards in October 2014, submitted its application in November 2014, received a PD and Alternate PD in January 2016 and received a final decision in May 2016.[27] Thus, CEJA/Sierra Club are asking

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[24] *Clean Energy Fuels Corp. v. Pub. Utilities Comm'n*, 227 Cal. App. 4th 641, 649 (2014).

[25] *Greyhound Lines, Inc. v. Pub. Utilities Comm'n*, 68 Cal. 2d 406, 410 (1968).

[26] CEJA/Sierra Club AFR at 1-2.

[27] Exhibit SCE-1, SCE's Opening Testimony, at 4, 9-11, 28, Exhibit SCE-2, Appendix D: IE Report, at D-67-D-72.

the Commission to negate nearly three years' worth of work and countless hours of resources that went into the planning, organization and administration of an RFO that SCE was ordered to conduct (including developer time and resources dedicated to bid submittal and investor approval), that not only involved consultation with an Independent Evaluator ("IE"), but SCE's Cost Allocation Mechanism ("CAM") Group and ED.[28] The LCR RFO was unprecedented in breadth and complexity and employed countless hours of resources to determine contracts, valuation parameters, and selection processes. CEJA/Sierra Club, however, turn this complex process on its head by arguing that a single qualitative factor negates all other factors and all of this effort. CEJA/Sierra Club argue that environmental justice issues must be considered at any cost and above all other factors in determining procurement selections. This position has no basis in the law and should be rejected.

As demonstrated in D.16-05-050, and supported by the record in this proceeding, including SCE's Application, testimony, and filings, the Commission's approval of the Puente contract is reasonable, consistent with least-cost best-fit ("LCBF") principles,[29] needed to meet long-term local capacity requirements, and satisfies the procurement authorization granted by the Commission. CEJA/Sierra Club's claims that the Commission unlawfully approved the Puente contract fail for the reasons set forth below, and as a result, their AFR should be denied.

a) The Commission's Consideration of Environmental Justice Issues in the Approval of the Puente Contract is Reasonable

CEJA/Sierra Club argue that "[b]y failing to acknowledge that the 'criteria laid out in D.13-02-015' includes environmental justice in procurement, and by failing to apply other laws, rules and precedent, the Commission fails to proceed in the manner required by

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[28] *See* Exhibit SCE-1, SCE's Opening Testimony, at 19-22; Exhibit SCE-2, Appendix D: IE Report; Exhibit SCE-3: Appendix E: Solicitation Materials.

[29] *See* D.04-12-048 at 158 ("The Commission has adopted the policy of LCBF which dictates that the IOUs obtain the best and most cost effective product for their customers.").

law."[30] Specifically, CEJA/Sierra Club argue that the Commission's finding that the reference to environmental justice in D.07-12-052 is "dicta" and "remains in effect as guidance"[31] fails for three reasons: (1) the Commission cannot "diminish the legal significance of environmental justice" because it is not referenced in an ordering paragraph; (2) the Commission included the environmental justice guidance in D.07-12-052 in the 2010 Procurement Policy Manual; and (3) "nothing in D.07-12-052 suggests that implementation of environmental justice considerations in procurement must await additional 'guidance.'"[32] CEJA/Sierra Club's arguments should be rejected.

First, the reasoning behind CEJA/Sierra Club's argument that the Commission somehow "diminish[ed] the legal significance of environmental justice" because it is not referenced in an ordering paragraph is not sound. The decision that CEJA/Sierra Club reference to support their position is not on point and their reliance on it is misplaced. The discussion in D.14-12-024 focused on whether the Commission had a policy "regarding the use of back-up generation in demand response programs" and provided a "historical timeline of Commission decisions regarding backup generation" that went back as far as 2003.[33] The decision pointed out that the Commission had "clearly adopted a policy statement…in [D.11-10-003] both the discussion and a conclusion of law."[34] The policy statement being supported by the Commission in D.14-12-024 is different than the statement made in D.07-12-052 regarding providing "greater weight" to "disproportionate resource sitings in low income and minority communities."[35] The statement in D.14-02-024 provided clear direction, specifically, "[a]s a general policy, we do not want to allow fossil-fueled emergency back-up generation to receive

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[30] CEJA/Sierra Club AFR at 6.
[31] D.16-05-050 at 17.
[32] CEJA/Sierra Club AFR at 6-7.
[33] D.14-12-024 at 52-53.
[34] *Id.* at 55.
[35] D.07-12-052 at 157.

system or local RA credit as demand response resources[,]"[36] and was supported by years of Commission decisions supporting the statement.[37] The statement in D.07-12-052 was clear, but was not presented "as a general [Commission] policy" and certainly was not supported by years of precedent. Therefore, CEJA/Sierra Club's reliance on D.14-12-024 to establish its argument is misplaced.

CEJA/Sierra Club's reliance on the "2010 Procurement Policy Manual" is also misplaced. CEJA/Sierra Club contend that because the Procurement Manual references D.07-12-052 and its discussion regarding providing "greater weight" to "disproportionate resource sitings in low income and minority communities[,]"the discussion in D.07-12-052 should not be viewed as "dicta."[38] However, the Commission has declined to "adopt" the Rulebook/Procurement Policy Manual "as a standalone enforceable document."[39] Therefore, CEJA/Sierra Club's reliance on the Manual is misplaced.

Finally, CEJA/Sierra Club argue that "nothing in D.07-12-052 suggests that implementation of environmental justice considerations in procurement must await additional 'guidance.'"[40] SCE does not dispute that D.07-12-052 states the following:

> Some criteria for which we believe the IOUs need to provide greater weight include disproportionate resource sitings in low income and minority communities, and environmental impacts/benefits (including Greenfield vs. Brownfield development).[41]

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[36] *See* D.11-10-003 at 26 ("As a general policy, we do not want to allow fossil-fueled emergency back-up generation to receive system or local RA credit as demand response resources. In decisions on the IOUs' last three demand response program budget cycles (2005-2011), we have consistently stated that demand response programs that rely on using back up generation were contradictory to our vision for demand response and the Loading Order.").

[37] D.14-12-024 at 53-55.

[38] CEJA/Sierra Club AFR at 7.

[39] D.12-04-046 at 63.

[40] CEJA/Sierra Club AFR at 7.

[41] D.07-12-052 at 155-156.

However, the parties' sole focus is on the environmental justice criterion, while disregarding the "Greenfield vs. Brownfield" criterion and an *order* in the very same decision that states: "IOUs are to consider the use of Brownfield sites *first* and take full advantage of their location *before they consider building new generation on Greenfield sites*. If IOUs decide not to use Brownfield, *they must make a showing that justifies their decision*."[42] D.07-12-052 did not find, conclude or order that "disproportionate resource sitings in low income and minority communities" should supersede all other quantitative and qualitative criteria or that it should be an overarching consideration when selecting a contract. The Commission simply stated that there are "criteria for which we believe the IOUs need to provide greater weight."[43] The Commission did not recommend providing "greater weight" to those factors despite the costs to customers and at the cost of all other quantitative and qualitative considerations evaluated through the LCBF methodology. SCE relied on the Commission's order that "IOUs are to consider the use of Brownfield sites *first* and take full advantage of their location *before they consider building new generation on Greenfield sites*."[44] In this instance, this meant not creating additional environmental impacts by selecting a greenfield site.

(1) <u>The Commission Properly Concluded That Public Utilities Code Section 399.13(a)(7) Does Not Apply to Resources Sought Through the LCR RFO</u>

CEJA/Sierra Club's reliance on Public Utilities Code Section 399.13(a)(7) to support its environmental justice arguments is misplaced.[45] CEJA attempts to apply a statute that regulates the Renewables Portfolio Standard ("RPS") Program, including RPS procurement, to the LCR RFO procurement ordered through the Long Term Procurement

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[42] D.07-12-052 at 305 (Ordering Paragraph ("OP") 35) (emphasis added); *see also* D.04-12-048 at 159, 222 (Finding of Fact ("FOF") 101), 235 (Conclusion of Law ("COL") 28).

[43] D.07-12-052 at 155-156.

[44] D.07-12-052 at 305 (OP 35) (emphasis added); *see also* D.04-12-048 at 159, 222 (FOF 101), 235 (COL 28).

[45] CEJA/Sierra Club AFR at 8-9.

Plan ("LTPP") proceeding in D.13-02-015. Public Utilities Code Section 399.13 provides for requirements related to the utilities' RPS procurement plans and RPS solicitations, but does not apply to non-RPS solicitations. The resources procured through the LCR RFO were not procured through the RPS program, they were procured by order in the LTPP proceeding. CEJA's application of the statute is also misplaced. Section 399.13 provides that the utilities should give preference to RPS projects that provide benefits to environmental justice communities.[46] For the LCR RFO, SCE selected every renewable project that was available, eliminating the need for this preference.

b) <u>The Commission's Decision is Not Discriminatory</u>

CEJA/Sierra Club argue that the Commission has failed to comply with the state's anti-discrimination laws by approving the Puente project.[47] This argument should be rejected.

First, CEJA/Sierra Club's reliance on Government Code Section 65040.12(e) is misplaced.[48] Government Code Section 65040 is applicable to the Governor's Office of Planning and Research.[49] Government Code Section 65040.12(a) states that "[t]he office shall be the coordinating agency in state government for environmental justice programs[;]" and in Section 65040.12(e) goes on to state that "[f]or the purposes of this section, 'environmental justice' means the fair treatment of people of all races, cultures, and incomes with respect to the development, adoption, implementation, and enforcement of environmental

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46 Cal. Pub. Utilities Code § 399(a)(7): "In soliciting and procuring eligible renewable energy resources for California-based projects, each electrical corporation shall give preference to renewable energy projects that provide environmental and economic benefits to communities afflicted with poverty or high unemployment, or that suffer from high emission levels of toxic air contaminants, criteria air pollutants, and greenhouse gases."

47 CEJA/Sierra Club AFR at 9-10.

48 *Id*. at 9.

49 Cal. Gov't Code § 65040 ("The Office of Planning and Research shall serve the Governor and his or her Cabinet as staff for long-range planning and research, and constitute the comprehensive state planning agency.").

laws, regulations, and policies."[50] Thus, CEJA/Sierra Club's argument that the obligations of the Governor's Office of Planning and Research are applicable to the Commission is incorrect.

CEJA/Sierra Club also assert that D.16-05-050 violates Government Code Section 11135. Government Code Section 11135(a) states:

> No person in the State of California shall, on the basis of race, national origin, ethnic group identification, religion, age, sex, sexual orientation, color, genetic information, or disability, be unlawfully denied full and equal access to the benefits of, or be unlawfully subjected to discrimination under, any program or activity that is conducted, operated, or administered by the state or by any state agency, is funded directly by the state, or receives any financial assistance from the state.[51]

Thus, CEJA/Sierra Club are claiming that the Commission's approval of the Puente contract was an act of discrimination based on "race, national origin, ethnic group identification, religion, age, sex, sexual orientation, color, genetic information, or disability."[52] The Commission's approval of the Puente contract was not an act of discrimination as represented in Section 11135, and as a result, CEJA/Sierra Club's argument fails.

c) <u>**The Commission Appropriately Considered Whether SCE Followed Its Procurement Plan**</u>

CEJA/Sierra Club assert that by "failing to conduct Commission review of SCE's procurement plan…the Commission has unlawfully denied the parties their constitutional right to due process."[53] This is not correct. The Commission appropriately determined that this proceeding was intended to "consider[] whether SCE followed its Procurement Plan, not whether the plan itself was adequate."[54]

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[50] Cal. Gov't Code § 65040.12(e).
[51] Cal. Gov't Code § 11135(a).
[52] *Id.*
[53] CEJA/Sierra Club AFR at 11.
[54] D.16-05-050 at 18.

CEJA/Sierra Club contend that "it is the Commission's statutorily-mandated duty, not the Energy Division's, to review and approve IOU procurement plans."[55] They also claim that it was improper for the Commission to find that "[i]f CEJA or another party contended that the process authorized in D.13-05-015 for review of SCE's procurement plan was unlawful, they could have filed an application for rehearing of that decision on this point."[56] Yet, CEJA and Sierra Club were parties to the LTPP Track 1 and 4 proceedings, so they should have been aware, when it was issued, that the Track 1 decision ordered SCE to submit its LCR Procurement Plan to Energy Division for approval. CEJA and Sierra Club could have challenged the Commission's order at that time, but failed to do so. Indeed, both CEJA and Sierra Club filed a petition for modification in the 2012 LTPP proceeding seeking to modify the LTPP Track 4 decision to require formal notice of and comment on the LCR procurement plan that San Diego Gas & Electric Company ("SDG&E") was ordered to submit to ED for approval.[57] Thus, these parties should have been aware, based on previous experience, that they could and should have filed their challenge to the Commission's decision to "delegate its power to the Energy Division without retaining final approval and review"[58] in the 2012 LTPP proceeding. Furthermore, contrary to CEJA/Sierra Club's claims, the Commission's finding on this issue does not state that the "parties waived rights to challenge the procurement plan;"[59] instead, the Commission properly held that if the parties disagreed with the process for utility procurement plan approval that was established in the LTPP Track 1 proceeding, they should have challenged D.13-02-015 on *that* point (*i.e.*, the process authorized for review of SCE's LCR procurement plan). Accordingly, the parties' arguments on this issue are procedurally improper, lack merit, and should be rejected.

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[55] CEJA/Sierra Club AFR at 12.
[56] D.16-05-050 at 18.
[57] D.14-08-008 at 4.
[58] CEJA/Sierra Club AFR at 11.
[59] *Id.*

d) <u>The Commission Did Not Need to Conduct CEQA Review Before Approving the Puente Contract</u>

CBD, Oxnard and CEJA/Sierra Club contend that the Commission unlawfully approved the Puente contract before (1) conducting an environmental review of the project pursuant to CEQA or (2) awaiting completion of environmental review by the California Energy Commission ("CEC").[60] These arguments are incorrect. The Commission has a long-standing precedent, going back 30 years, of consistently rejecting the arguments raised by the parties.[61] Over the years, the Commission has clearly defined its appropriate role in approving long-term contracts/power purchase agreements ("PPAs"). For example, in a proceeding in which cost recovery was being sought for five PPAs negotiated between SCE and County Sanitation Districts of Los Angeles County, the Commission stated in its decision that prior Commission decisions made clear that CEQA does not apply to Commission review of PPAs.[62] The Commission provided the following rationale:

> [O]ur jurisdiction with respect to power purchases extends to the electric utility, not the qualifying facility. Specifically, we are empowered to determine and approve the prices, terms, and conditions of the electric utility's purchase of power from the qualifying facility.
>
> At issue in this proceeding, as in each case involving the review of a nonstandard agreement, is the prudency of the economic terms of the utility's purchase of power from the qualifying facility and not the adequacy of the facility itself. We note that the Sanitation Districts' requested relief is limited to such a prudency determination which would assure Edison of recovery of costs associated with the agreements through rates. Such an order is one which is quite clearly an exercise of our ratemaking authority to

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[60] *See* CBD AFR at 4-22; Oxnard AFR at 1; CEJA/Sierra Club AFR at 14-15.

[61] *See, e.g*., Resolution E-4171 at 15-16; Resolution E-4439 at 18; Resolution E-4467 at 24; Resolution E-4686 at 17 ("'[T]he scope of this resolution is confined to assessing…whether the price and terms of the PPA are reasonable; and whether payments made by PG&E under the CA Flats PPA are fully recoverable in rates. Approval of PG&E's anticipated costs for the CA Flats PPA is not an 'approval' of a 'project' within the meaning of CEQA."); D.86-06-060 at 29-30; D.86-10-044 at 16-18.

[62] D.86-06-060, 1986 Cal. PUC LEXIS 424, at *29 (June 25, 1986).

> which CEQA does not apply. We therefore find that a grant of the relief requested by the Sanitation Districts will not constitute a "project" subject to CEQA requirements.[63]

The Commission revisited this issue more recently in D.15-05-051, the decision approving SDG&E's LCR procurement, in which it stated:

> CEQA Guidelines, long-standing case law, and Commission precedent all make clear that Commission review of purchase power contracts does not trigger CEQA. A contract for purchase power by a regulated entity is not a "project" pursuant to CEQA. CEQA defines a "project" as "[a]ctivities involving the issuance to a person of a lease, permit, license, certificate, or other entitlement for use by one or more public agencies." (Public Resources Code § 21065.) Commission approval of a purchase power contract does not confer a lease, permit, license, certificate, or any other entitlement on the seller. Rather, it is an assurance that the utility will recover through its rates the costs that it incurs under the contract. It is well-settled that "[s]uch a ratemaking order is not [a] 'project' under CEQA." … Likewise, the Commission is not a "responsible agency" under CEQA when it approves purchase power contracts. A "responsible agency" is defined as a public agency other than the lead agency which has discretionary approval power over the project….While the Commission has considerable discretion over whether to approve a purchase power contract, it does not have power to approve or deny the underlying generation project. The project underlying the purchase power contract could proceed regardless of the Commission's decision.[64]

None of the AFRs has provided any basis upon which to alter the Commission's past practice and precedent; thus, their arguments should be rejected.

In its AFR, Oxnard refers back to the arguments in its briefing,[65] where it asserts that the "approval of the NRG contract will significantly constrain the CEC's ability to

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[63] *Id*. at *29-30 (internal citations omitted).

[64] D.15-05-051 at 29-30. *See also* D.15-11-024 (In purchase power tolling agreement "applications, the utility, and not the project proponent, is the applicant. Here, we do not have jurisdiction over…the underlying project proponent, and do not approve or disapprove the generation project itself. It is [project proponent] which is actually proposing to construct the plant, and its application to construct the…Project has been considered by the California Energy Commission ("CEC") in separate proceedings outside of this agency.").

[65] Oxnard AFR at 1.

consider project alternatives."[66] Although the City has not substantiated this claim, it argues that based on *Save Tara v. City of West Hollywood*, "before conducting CEQA review, agencies must not 'take any action' that significantly furthers a project 'in a manner that forecloses alternatives or mitigation measures that would ordinarily be part of CEQA review of that public project.'"[67] However, *Save Tara* is distinguishable from Commission precedent on the "project" issue. In *Save Tara*, "an agency reache[d] a binding, detailed agreement with a private developer and publicly committed resources and governmental prestige to [the] project," so that "as a practical matter, the agency [] committed itself to the project as a whole…effectively preclud[ing] any alternatives or mitigation measures that CEQA would otherwise require to be considered…."[68] As the Commission has stated in past precedent, when the Commission approves a PPA, it is not conferring a type of entitlement on the seller, such as a lease, nor does the Commission have discretionary approval over such projects – in *Save Tara*, there was clearly a "project" and the City of West Hollywood was most definitely a "responsible agency," as the city was involved in developing and approving the project. Moreover, the PPAs approved by the Commission have termination rights based on a failure to obtain permitting. The facts in this proceeding are distinguishable from *Save Tara* and Oxnard's reliance upon the case is misplaced. As a result, Oxnard's argument should be rejected.

e) <u>The Commission's Approval of the Puente Contract is Supported by the Record in this Proceeding</u>

CEJA/Sierra Club argue that D.16-05-050 "errs in concluding that SCE relied on both quantitative (and non-hearsay) factors and qualitative (and admittedly hearsay) factors to award the contract for the Puente Project" because it took "at face value SCE's assertion that 'the qualitative factors reinforced SCE's quantitative assessment that the NRG

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66 Oxnard Opening Brief at 18.
67 *Save Tara v. City of West Hollywood*, 45 Cal. 4th 116, 138 (2008).
68 *Id.* at 139.

Energy Center was the best option to meet the LCR need.'"[69] CEJA/Sierra Club go so far as to claim that "SCE did not, in fact, combine, 'qualitative and quantitative factors' to arrive at its conclusion to award a contract for the Puente Project; it relied on the hearsay, qualitative factor to offer to restructure the terms with NRG."[70] As a result, CEJA/Sierra Club claim that the Commission incorrectly relied on hearsay in approving the Puente contract.[71] CEJA/Sierra Club's claims are flawed and demonstrate a lack of understanding of SCE's valuation and selection process, and therefore, should be rejected.[72]

SCE utilized a least-cost, best-fit methodology in evaluating final offers for the Moorpark sub-area.[73] In SCE's Opening Testimony, there is an entire chapter devoted to explaining SCE's valuation process and the criteria used during its evaluation and selection of offers.[74] The chapter contains details surrounding SCE's valuation and selection methodology, including the "quantitative component of the evaluation [which] entails forecasting (1) the value of the contract benefits, (2) the value of the contract costs, and (3) the net value between (1) and (2),"[75] and a discussion on the assessment of qualitative attributes, or the "non-quantifiable characteristics of each offer."[76] In the same chapter, SCE provides a summary of the valuation results[77] and its selections.[78]

As explained in SCE's Opening Testimony, SCE's quantitative valuation is not influenced by qualitative factors.[79] SCE's quantitative assessment is simply an unbiased

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69 CEJA/Sierra Club AFR at 15.
70 *Id*. at 16.
71 *Id*. at 15.
72 SCE also responded to these arguments in its Reply Brief. *See* SCE's Reply Brief at 9-12.
73 Exhibit SCE-1C, SCE's Opening Testimony, at 30 ("In accordance with D.04-12-048, SCE used a LCBF methodology to value and award contracts in the LCR RFO.").
74 *Id*. at 30-49.
75 *Id*. at 31.
76 *Id*. at 39.
77 The results of the valuation analysis for all offers can be found in SCE's workpapers at Exhibit CO-5C at 139-162.
78 Exhibit SCE-1C, SCE's Opening Testimony, at 41-49.
79 *Id*. at 31-38.

forecast of each offer's benefits and costs to SCE's customers,[80] and forms the basis for the "cost" in SCE's LCBF methodology. The quantitative assessment of every offer in the LCR RFO was conducted consistently across all offers using the same valuation framework and market price forecasts (energy, ancillary services, and resource adequacy price forecasts), without regard for qualitative concerns. Under this objective number-based valuation, the Puente contract offer provided the most value to SCE's customers from those offers that would be needed to meet the Commission's minimum LCR procurement requirement. Furthermore, the valuation framework and market price forecasts were established and prepared before offers were received, and validated by SCE's IE.[81] Specifically, for gas-fired generation ("GFG"), SCE utilized the same production-cost model (using each offer's operating characteristics such as capacity, heat-rates, start costs, etc.), the same Monte Carlo simulation, and the same discounting methodology to arrive at each offer's net present value ("NPV").[82]

SCE did use qualitative factors to arrive at its final selection of offers;[83] the qualitative factors SCE considered in selecting the Puente contract included the project being located on a brownfield site and the [redacted] [84] However, the selection of the Puente contract was not based entirely on a qualitative factor as CEJA/Sierra Club claim.[85] Nor was the qualitative factor the reason SCE structured the Puente contract as an RA-only contract. Indeed, SCE had already completed its quantitative assessment of the GFG

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[80] *Id*. at 31-32 ("The quantitative component of the evaluation entails forecasting (1) the value of the contract benefits, (2) the value of the contract costs, and (3) the net value between (1) and (2). SCE calculated each offer's forecasted quantity of RA capacity, electrical energy, and AS using a combination of models specific to each resource type. SCE then multiplied these quantities by the respective market price forecasts. These calculations represent (1) the value of the contract benefits based on the forecasted market value for each resource. SCE then calculated (2) the contract costs required to realize this market value, including estimates of capacity payments, variable operations and maintenance ("VOM") costs, start-up payments, and fuel costs to generate electrical energy. These elements were used to determine the cost effectiveness of each resource.").

[81] Exhibit SCE-2, Appendix D: Independent Evaluator Report, at D-24.

[82] Exhibit SCE-1, SCE's Opening Testimony, at 34.

[83] *Id*. at 39, 44.

[84] *Id*. at 56; Exhibit SCE-2C, Appendix D: Independent Evaluator Report, at D-69.

[85] CEJA/Sierra Club AFR at 16.

final offers and made its final offer selection [redacted].[86] As stated in the IE Report submitted with SCE's Opening Testimony:

> [redacted][87]

Thus, as confirmed by the IE Report, the qualitative factors discussed above *did reinforce* SCE's quantitative assessment that the Puente project was the best option to meet the LCR need, and SCE's selection of the Puente contract was not a result of its reliance on a "hearsay, qualitative factor."[88] Thus, CEJA/Sierra Club's argument that the Commission relied on hearsay to approve the Puente contract is without basis and should be rejected.

Moreover, contrary to CEJA/Sierra Club's assertion, the Commission can give some weight to SCE's consideration of the [redacted] as part of its qualitative analysis.[89] "The Commission's proceedings are governed by its rules of practice and procedure, 'and in the conduct thereof the technical rules of

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[86] Exhibit SCE-2, Appendix D: Independent Evaluator Report, at D-71 – D-72 [redacted]

[87] *Id*. at D-69.

[88] CEJA/Sierra Club AFR at 16.

[89] *Id*. at 16-17.

evidence need not be applied.'"[90] "The Commission's own precedent establishes that hearsay evidence is admissible in its proceedings [; and] [t]he Commission generally allows hearsay evidence if a responsible person would rely upon it in the conduct of serious affairs."[91] The Commission has also found that "'hearsay evidence is admissible in an administrative hearing and may be relied upon if supported by other credible evidence.'"[92] The [redacted] was one factor considered in SCE's qualitative analysis, and thus, would not "not serve as the *sole* factual basis for [a] Commission[] finding[,]" approving the Puente contract.[93] As demonstrated in SCE's Application, testimony (and appendices and workpapers in support thereof), and briefing, there is certainly "other competent, substantial evidence [that would] support [a] Commission[] decision"[94] approving the Puente contract.

2. __D.16-05-050's Approval of the Results of the LCR RFO is Not Unlawful, Erroneous or an Abuse of Discretion__

CBD argues that the Commission's approval of the results of the LCR RFO is in violation of the Loading Order and the Track 1 decision.[95] CBD's AFR relies heavily on the argument that the Commission abused its discretion and acted unlawfully because it did not make any findings of fact or conclusions of law on certain issues that CBD believes are material to the proceeding.[96] This argument is flawed. As the Commission determined in D.16-05-053:

> It is within the Commission's discretion to determine what factors are material to its decision based on the issues before it. (*Clean Energy Fuels*

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90 *Util. Reform Network v. Pub. Utilities Comm'n*, 223 Cal. App. 4th 945, 959 (2014) (citing Public Utilities Code § 1701); *see* Rule 13.6(a) of the California Public Utilities Commission Rules of Practice and Procedure.

91 *Id*. at 959-960 (internal quotation marks and citations omitted).

92 D.99-01-029 at 7.

93 *Util. Reform Network v. Pub. Utilities Comm'n*, 223 Cal. App. 4th at 963.

94 *Id*.

95 CBD AFR at 2-4, 25.

96 *See* CBD AFR at 4, 23, 25, 27, 30, 32-33, 36.

> *Corp., v. Public Utilities Commission* (2014) 227 Cal. App. 4th 641, 659.) The Commission's "findings and conclusions are sufficient if they provide 'a statement which will allow us a meaningful opportunity to ascertain the principles and facts relied upon by the [Commission] in reaching its decision." (*Toward Utility Rate Normalization v. Public Utilities Com.* (1978) 22 Cal.3d 529, 540.) In other words, "a complete summary of all proceedings and evidence leading to the decision" is not required. (*Ibid.*) [Public Utilities Code] Section 1705 does not require the Commission to make express legal and factual findings as to each and every issue or sub-issue raised in a scoping memo or by a party to the proceeding.[97]

CBD's arguments also fail for the reasons set forth below. Therefore, the Commission should deny CBD's AFR.

a) <u>The Commission's Approval of the Results of the LCR RFO was Reasonable</u>

CBD makes a blanket assertion that that "[t]he RFO process was biased against Preferred Resources"[98] and argues that the RFO was "designed to discourage Preferred Resources."[99] These claims are baseless. As explained in its testimony and filings,[100] SCE did a tremendous amount of outreach to encourage the participation of all potential bidders in the LCR RFO, especially Preferred Resource bidders.[101] As stated in the IE Report, "Sedway Consulting concluded that SCE did a good job of publicizing the 2013 LCR RFO solicitation, and that the solicitation was quite robust, as evidenced by the substantial response that it received from the bidding community."[102] The IE Report went on to state that "[o]ver 200 Moorpark offers from more than 30 bidders were received. It was quite a robust response and included bids from all resource categories – as well as some new products that were not easy to categorize or which

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[97] D.16-05-053 at 6.
[98] CBD AFR at 22.
[99] *Id.* at 28.
[100] *See* Exhibit SCE-1, SCE's Opening Testimony, at 12, 15-16; Exhibit SCE-2, Appendix D: Independent Evaluator Report, at D-17, D-34 – D-35; Exhibit SCE-3, Appendix E: LCR Solicitation Materials; Exhibit SCE-7C, SCE's Rebuttal Testimony, at 12-13; SCE's Opening Brief at 13-15.
[101] *See id.* for information on SCE's LCR RFO outreach efforts.
[102] Exhibit SCE-2, Appendix D: Independent Evaluator Report, at D-35; *see also* SCE's Reply Brief at 23.

needed the development of a new product category, contract, and/or revised evaluation approach."[103] Ultimately, SCE selected all Preferred Resource final offers for the Moorpark sub-area, with the exception of some in-front-of-the-meter Energy Storage.[104]

CBD also suggests "[t]hat there are sufficient Preferred Resources available in the Moorpark sub-area to fill the LCR need."[105] However, if the Preferred Resources identified by CBD[106] were truly available and viable alternatives to the projects selected by SCE, including being incremental resources, then those resources should have been bid into the LCR RFO for the Moorpark sub-area. Projects not bid into the LCR RFO could not be evaluated and selected by SCE.

CBD also makes the following arguments in support of its claim that the Commission's approval of the RFO results was unlawful:

(1) CBD's Argument That "SCE Impermissibly Solicited Offers for Resources to Be Operational Well Before the Ordered Date of 2021"[107] Fails

CBD argues that SCE impermissibly solicited offers for resources to be operational before 2021, thus, the Commission's approval of the results of the LCR RFO was an abuse of discretion.[108] This is incorrect. In its Track 1 Procurement Plan, which was approved by Energy Division prior to the launch of the LCR RFO,[109] SCE stated that it would be

103 Exhibit SCE-2, Appendix D: Independent Evaluator Report, at D-17; *see also* SCE's Opening Brief at 13.

104 Exhibit SCE-1, SCE's Opening Testimony, at 50; Exhibit SCE-2C, Appendix D: Independent Evaluator Report, at D-74, D-76, D-78.

105 CBD AFR at 25.

106 CBD states that the Southern California Regional Energy Network identified 200 MW of Preferred Resources available in the Moorpark sub-area. CBD AFR at 25.

107 CBD AFR at 26.

108 *Id.* at 26-27.

109 Exhibit SCE-1, SCE's Opening Testimony, at 4; *see also* SCE's Reply Brief at 29.

soliciting offers in the RFO that would be online as early as 2015 in the Goleta area.[110] This is consistent with the Track 1 decision, which did not prohibit resources coming online before 2021 but merely required that resources be online *by* 2021.[111] Therefore, CBD's argument fails.

(2) <u>CBD's Argument That "The RFO Schedule Did Not Allow Sufficient Time for Preferred Resources Vendors to Participate"[112] is Unsubstantiated</u>

CBD asserts that "[t]he Commission did not make any findings of fact or conclusions of law regarding the material issue of whether the timing of the RFO was prejudicial to [P]referred [R]esource vendors."[113] As discussed above, this claim does not render D.16-05-050 unlawful or erroneous.

Moreover, CBD's claim that the RFO was "prejudiced against [P]referred [R]esource participation" is unsupported.[114] During the bidding and negotiation phase of the solicitation, the SCE LCR procurement team expended numerous hours with Preferred Resource bidders, walking them through the bid and award process and facilitating their ability to submit a final bid.[115] Additionally, the contractual delivery date security posting amount, which selected offers are required to post to SCE until delivery starts, on a $/kW basis was generally lower for Preferred Resources than conventional resources.[116] In short, SCE worked collaboratively and diligently with stakeholders and bidders to remove potential

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[110] Exhibit SCE-10, SCE's LCR RFO Procurement Plan, at 8-9; *see also* SCE's Reply Brief at 29. The 2015 date was later delayed to 2016 to reflect the delay in the schedule of the LCR RFO. *See* Exhibit SCE-1, SCE's Opening Testimony, at 9-11.

[111] D.13-02-015 at 131 (OP 2) ("[SCE] shall procure between 215 and 290 [MW] of electric capacity to meet local capacity requirements in the Moorpark sub-area of the Big Creek/Ventura local reliability area *by* 2021.") (Emphasis added); *see also* SCE's Reply Brief at 29.

[112] CBD AFR at 27.

[113] *Id.* at 27.

[114] *Id.* at 28.

[115] Exhibit SCE-7C, SCE's Rebuttal Testimony, at 13; *see also* SCE's Opening Brief at 15.

[116] *Id.*

obstacles that may have interfered with the ability of Preferred Resource service providers to contract with SCE.

Furthermore, the LTPP Track 1 decision required SCE to file one Application for approval of any and all contracts entered into as a result of the procurement process for new capacity in the Moorpark sub-area, and one Application for these purposes for the Western LA Basin.[117] Given these requirements for SCE's LCR RFO Applications, simultaneous competitive procurement of all resource types was necessary.[118] SCE held one LCR RFO and solicited resources for both the Western LA Basin and the Moorpark sub-area in that RFO.[119] In its Track 1 Procurement Plan approved by the Energy Division,[120] SCE expressed its intention to solicit resources in the Western LA Basin and Moorpark sub-areas through the LCR RFO.[121] Conducting one RFO in which resources would be sought from two procurement areas was reasonable, especially considering the Commission's directive that there was "an immediate need to begin a procurement process to meet LCR needs…in the Moorpark sub-area"[122] and "due to a seven to nine year lead time for conventional gas-fired resources."[123] Thus, SCE attempted to facilitate maximum participation of Preferred Resources in its solicitation consistent with the RFO timelines the Commission recommended and approved.

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[117] D.13-02-015 at 135 (OP 11); *see also* SCE's Reply Brief at 33.
[118] *See* SCE's Reply Brief at 33.
[119] *Id.*
[120] Exhibit SCE-1, SCE's Opening Testimony, at 4; *see also* SCE's Reply Brief at 33.
[121] Exhibit SCE-10, Track 1 Procurement Plan of Southern California Company Submitted to Energy Division Pursuant to D.13-02-015, at 4, 13; *see also* SCE's Reply Brief at 33.
[122] D.13-02-015 at 125 (FOF 42); *see also* SCE's Reply Brief at 33.
[123] *Id.* at 122 (FOF 25); *see also* SCE's Reply Brief at 33.

(3) **CBD's Arguments Attempting to Establish That "The RFO Was Otherwise Designed to Discourage Preferred Resources"[124] Lack Merit**

CBD argues that by approving the results of an RFO that was conducted in violation of Commission orders and the Loading Order, the Commission acted unlawfully and engaged in abuse of discretion. CBD's arguments in support of this claim lack merit for the reasons discussed below.

(a) **"Failure to Provide Draft Contracts for DG Resources"[125]**

CBD asserts that the LCR RFO was designed to discourage Preferred Resources because SCE did not offer bidders a pro forma agreement for Distributed Generation ("DG") resources.[126] Although SCE did not have a pro forma DG contract, SCE communicated through the RFO documents and at the bidder's conference that it was willing to work with bidders to customize contracts.[127] Offers were submitted for DG and SCE ultimately signed customized DG contracts with SunPower (parent company of Solar Star California).[128]

(b) **"Security Required"[129]**

CBD claims that "the requirement of security prejudiced the RFO against [P]referred [R]esources."[130] This claim is unsubstantiated. Although SCE required some level of development security for all resources to help ensure the resources

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[124] CBD AFR at 28.
[125] *Id.*
[126] *Id.* at 28-29.
[127] Exhibit SCE-3, Appendix E: Solicitation Materials, at E-11, E-25, E-137; *see also* SCE's Reply Brief at 29.
[128] Exhibit SCE-1, SCE's Opening Testimony, at 52-53; *see also* SCE's Reply Brief at 29.
[129] CBD AFR at 29.
[130] *Id.*

showed up to maintain the reliability of the system, SCE had different development security requirements for different products.[131] In fact, the development security amount for Preferred Resources was significantly lower than that of GFG.[132]

(c) **"Resources Excluded Based on CAISO Failure to Study"**[133]

CBD argues that SCE wrongfully excluded two-hour products, and the Commission wrongly deferred to the California Independent System Operator ("CAISO") on this issue.[134] Although a two-hour product may have contributed to the LCR need, it ultimately would not have counted towards Resource Adequacy ("RA") requirements under the current rules, which require four-hour products. It is important to note that while SCE was working with the CAISO to identify minimum operational characteristics for LCR resources (as required by the LTPP Track 1 Decision), participants in the LCR RFO were required to submit offers for four-hour resources in addition to any lower duration.[135] In addition, SCE requested that the final decision in the 2014 RA proceeding adopt a CAISO-defined quantity of two-hour resources that will meet the LCR need.[136] SCE's request was denied. Instead, the Commission directed the Energy Division to work with the CAISO to further refine policies regarding this issue.[137] Thus, the Commission and CAISO are still working through the issues of allowing two-hour resources to count towards grid reliability requirements.

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[131] Exhibit SCE-3, Appendix E: Solicitation Materials, at E-153; *see also* SCE's Reply Brief at 29-30.
[132] *Id*.
[133] CBD AFR at 29.
[134] *Id*. at 29-30.
[135] Exhibit SCE-2, Appendix D: Independent Evaluator Report, at D-23 ("[A]ll bidders of applicable products (ES and DR) were required to provide 4-hour bids to be deemed compliant with the RFO instructions but had been given the option to provide 2-hour offers…."); *see also* SCE's Reply Brief at 27.
[136] R.11-10-023, Opening Comments of Southern California Edison Company (U338-E) on the Proposed Decision Adopting Local Procurement and Flexible Capacity Obligations for 2015, and Further Refining the Resource Adequacy Program, June 16, 2014, at 2-3; *see also* SCE's Reply Brief at 27.
[137] D.14-06-050 at 31; *see also* SCE's Reply Brief at 27.

Furthermore, as the Commission made clear in the Track 1 decision, it was important that SCE procure resources through its LCR RFO that "would [] pas[s] [CA]ISO muster."[138] It was also important that the selected resources meet LCR requirements, which included RA compliance. Procuring resources that "would not pas[s] [CA]ISO muster"[139] and did not meet LCR requirements did not make sense because the products would have been ineffective in meeting critical reliability requirements, and thus, would not have allowed SCE to comply with the LTPP Track 1 decision.

(4) <u>CBD's Argument Challenging the Need Determination Established in the Track 1 Proceeding is Improper</u>

CBD argues that by approving SCE's procurement of 274.16 LCR MW, which is well within the 215-290 MW procurement authorization established in the LTPP Track 1 decision, the Commission has unlawfully failed to "ensur[e] that the IOUs do not procure more power than needed."[140] CBD also argues that the "Commission abused its discretion in granting complete deference to the opinions of CAISO" by not making "any findings of fact or conclusions of law on material[] issues regarding the accuracy of [CAISO's] modeling."[141] Both of these arguments are incorrect and improper for the reasons discussed below, and therefore, should be rejected. Moreover, the Commission has communicated its preference for not reconsidering the Commission's original need determinations.

> Our long term procurement proceedings are intended to monitor changes in forecasts. In order to permit timely action in response to Commission determinations of need for new generation resources, it is crucial that we not be sidetracked by second-guessing recent determinations absent evidence of significant errors.[142]

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[138] D.13-02-015 at 75.
[139] *Id.*
[140] CBD AFR at 30.
[141] *Id.*
[142] D.06-11-048 at 10.

(a) **The McGrath Peaker Was Modeled in the CAISO's Analysis**

CBD argues that the McGrath peaker was not modeled in the 2012 LTPP Track 1 analysis, therefore, the approval of procurement based on Track 1 modeling is an abuse of discretion.[143] The McGrath peaker was modeled in the CAISO's analysis which was utilized by the Commission to develop the needs authorization in the 2012 LTPP Track 1 proceeding.[144] Furthermore, as SCE testified, the McGrath peaker was modeled in the 2014-15 CAISO Transmission Plan.[145] Therefore, the Commission adequately considered the McGrath peaker in its analysis and no adjustment to the need authorization is necessary.

(b) **The 2014-2015 CAISO Transmission Plan Demonstrates That SCE's Procurement is Necessary to Maintain Reliability**

CBD argues that "[t]he Commission accorded CAISO undue deference and failed to make findings regarding the material issue of fact of whether the 2014-2015 Transmission Plan demonstrates that the Track 1 needs determination is still valid."[146] CBD also asserts that CAISO's 2014-15 Transmission Plan is irrelevant to the proceeding.[147] The 2014-15 Transmission Plan is clearly relevant. CBD's own witness cites to it multiple times throughout his testimony and CBD even submitted the plan into the record.[148]

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143 CBD AFR at 30-32.

144 SCE's initial statement in its Reply to Protests to its Application, "The McGrath peaker was not factored into CAISO's study" is incorrect. Since filing its Reply to Protests, SCE followed up with the CAISO, which conducted the studies which informed the 2012 LTPP Track 1 need determination, and received information confirming that McGrath was indeed modeled in the analysis. CBD asserts that "SCE never withdrew their original representation that the McGrath Peaker was not included" in the CAISO's modeling. CBD AFR at 32. This is incorrect. SCE corrected its misstatement in its Reply Brief in this proceeding, filed on August 5, 2015. *See* SCE's Reply Brief at 30.

145 SCE, Chinn, Tr., Vol. 2 at 235:26-28 (May 28, 2015); *see also* SCE's Reply Brief at 30.

146 CBD AFR at 32.

147 *Id*. at 33.

148 Exhibit CBD-03; *see also* SCE's Reply Brief at 30.

CBD also fails to understand the applicable reliability standards claiming that the Commission's LCR need determination is in violation of federal standards.[149] The determination of need and the critical contingency used to make that determination were already litigated in D.13-02-015 consistent with federal standards.[150] Furthermore, in addition to federal standards,[151] CAISO has the authority to establish more stringent requirements in alignment with their responsibility to ensure reliability.[152] One of these requirements is CAISO's Local Capacity Requirement which specifically states that for an N-1, system adjusted, followed by an N-2, voltage collapse in an area is not permissible.[153] CBD's failure to comprehend federal reliability standards as well as CAISO's LCR criteria[154] does not serve as grounds to reject the Commission's need authorization. The Commission's LCR need determination and the critical contingency which drove that determination are clearly in alignment with CAISO's LCR criteria and were fully litigated in D.13-02-015.[155] These standards in no way violate the federal North American Electric Reliability Corporation ("NERC") requirements. The conclusion of CAISO's 2014-15 Transmission Plan is relevant to this proceeding, utilizes appropriate planning standards, and clearly demonstrates that SCE's procurement is necessary to maintain reliability within the Moorpark sub-area.

(c) The Commission's Need Determination is Still Valid

CBD claims that changed circumstances have made the Track 1 need determination obsolete and would have the Commission reopen the Track 1 proceeding, and by not doing so the Commission failed to proceed in a manner required by

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149 CBD AFR at 33-34.
150 *See* SCE's Reply Brief at 31.
151 SCE, Chinn, Tr., Vol. 2 at 240:11-26; 241:24-28 (May 28, 2015); *see also* SCE's Reply Brief at 31.
152 Exhibit SCE-7, SCE's Rebuttal Testimony, at 10; *see also* SCE's Reply Brief at 31.
153 SCE, Chinn, Tr., Vol. 2 at 246:3-5 (May 28, 2015); *see also* SCE's Reply Brief at 31.
154 SCE explained the relationship between these two standards to CBD during hearings (SCE, Chinn, Tr., Vol. 2 at 246:2-6 (May 28, 2015)) and subsequently provided CBD with a copy of the CAISO Local Capacity Requirement Study Manual per its request; *see also* SCE's Reply Brief at 31.
155 *See* SCE's Reply Brief at 31.

law.[156] The CAISO 2014-15 Transmission Plan incorporated changed assumptions since the issuance of D.13-02-15.[157] Specifically, CBD highlights changes in the SCE demand forecast and energy storage targets.[158] The Commission, in coordination with the CEC and CAISO, developed the assumptions used in the 2014-15 CAISO TPP ensuring that accurate assumptions were incorporated into the analysis.[159] The 2014-15 CAISO TPP aligns with the Commission's Track 1 need determination and demonstrates that SCE's proposed procurement is necessary.

(d) <u>The Closure of the Ormond Beach Facilities is Certain</u>

CBD argues that the Commission abused its discretion and acted unlawfully by not addressing "[t]he issue of whether or not NRG will actually close the Ormond Beach Power Plant."[160] CBD's claim is baseless and should be rejected. There is no ambiguity with regard to the closure of the Ormond Beach Generating Station ("Ormond"). Pursuant to comments submitted by NRG to the State Water Resources Control Board on the April 2016 Draft Report of the Statewide Advisory Committee on Cooling Water Intake Structures ("Comments") on May 6, 2016 and a letter from NRG to the Commission regarding the retirement of Ormond, dated May 19, 2016, Ormond will *not* operate past December 31, 2020.

In NRG's Comments, NRG stated:

> NRG South [] has decided not to continue to retain a Track 2 compliance option for Ormond Beach. Accordingly, NRG South will discontinue the impingement and entrainment studies. Because completion of the studies is required to utilize Track 2, the decision to discontinue the studies effectively eliminates Track 2 as a compliance option for Ormond Beach. The State Water Board and the

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[156] CBD AFR at 34-35.
[157] Exhibit SCE-7, SCE's Rebuttal Testimony, at 11; *see also* SCE's Reply Brief at 31.
[158] CBD AFR at 36.
[159] *See* SCE's Reply Brief at 31.
[160] CBD AFR at 36.

> [Statewide Advisory Committee on Cooling Water Intake Structures] should continue to assume that **Ormond Beach will not operate after 2020**.[161]

Just as the Commission determined in the LTPP Track 1 proceeding,[162] the Ormond Beach units will not be in operation past December 31, 2020.

III.

ORAL ARGUMENT IS NOT NECESSARY

CBD requests oral argument for its AFR.[163] However, oral argument will not materially assist the Commission in resolving CBD's AFR. CBD alleges that D.16-05-050 violates the Loading Order, the LTPP Track 1 decision, CEQA, the Public Utilities and Public Resources Code, however, as discussed herein, its claims are unsupported by the law and record evidence. Therefore, D.16-05-050 does not (1) "adopt[] new Commission precedent or depart[] from existing Commission precedent without adequate explanation, (2) "change[] or refine[] existing Commission precedent," (3) present[] legal issues of exceptional controversy, complexity, or public importance," or (4) raise[] questions of first impression that are likely to have significant precedential impact."[164] Because CBD's AFR does not meet any of the foregoing criteria, its request for oral argument should be denied.

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[161] *See* Comments of NRG California South LP on the April 2016 Draft Report of the Statewide Advisory Committee on Cooling Water Intake Structures, dated May 6, 2016, at 3 (emphasis added), attached to SCE's Response to California Environmental Justice Alliance's Motion to Set Aside Submission and Reopen Record to Take Additional Evidence.

[162] *See* D.13-02-015 at 42, 68.

[163] CBD AFR at 37.

[164] Rule 16.3(a), Commission's Rules of Practice and Procedure.

IV.

CONCLUSION

For all of the foregoing reasons, SCE respectfully requests that the Commission expeditiously deny the Applications for Rehearing filed by the CBD, CEJA/Sierra Club and Oxnard.

Respectfully submitted,

JANET S. COMBS
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July 18, 2016

EXHIBIT F

Application No.: 14-11-016
Exhibit No.:
Witness: Robert Sparks

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.	Application 14-11-016

TESTIMONY OF ROBERT SPARKS
ON BEHALF OF THE
CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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.	Application 14-11-016

TESTIMONY OF ROBERT SPARKS
ON BEHALF OF THE
CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

Q. What is your name and by whom are you employed?

A. My name is Robert Sparks. I am employed by the California Independent System Operator Corporation (CAISO), 250 Outcropping Way, Folsom, California as Manager, Regional Transmission.

Q. Please describe your educational and professional background.

A. I am a licensed Professional Electrical Engineer in the State of California. I hold a Master of Science degree in Electrical Engineering from Purdue University, and a Bachelor of Science degree in Electrical Engineering from California State University, Sacramento. I have over 25 years of Transmission Planning and Operations Engineering experience in California.

Q. What are your job responsibilities?

A. I manage a group of engineers responsible for planning the CAISO controlled transmission system in southern California to ensure compliance with NERC, WECC, and CAISO Transmission Planning Standards in the most cost effective manner.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of how Southern California Edison Company's (SCE) 2013 request for offers (RFO) meets the local capacity requirement needs for the Moorpark sub-area as identified in Commission Decision (D.) 13-02-015 (Track 1 Decision). Specifically, my testimony details the results of the CAISO's 2014-2015 transmission plan and the effect of the RFO-selected resources on local capacity requirements for the Moorpark sub-area.

An overview of SCE's RFO-selected resources for the Moorpark sub-area are provided in Table 1, below.

Table 1 – Summary of SCE's Submitted RFO Selection

Product Category	Counterparty	Total Number of Contracts	Max Quantity (LCR MW)
Gas Fired Generation (GFG)	• NRG Energy Center Oxnard, LLC • NRG California South, LP	2	262.00
Energy Efficiency (EE)	• Onsite Energy Corporation	6	6.00
Renewable Distributed Generation (DG)	• Solar Star California XXXIV, LLC • Solar Star California XXXIX, LLC	2	5.66
Energy Storage (ES) In Front of Meter (IFOM)	• NRG California South, LP	1	0.50
Total		**11**	**274.16**

Q. How did the CAISO study the impact of SCE's RFO-selected resources on system reliability?

A. The CAISO used the SCE RFO results in its local capacity requirement analysis conducted as a part of the 2014-2015 transmission planning process. The results of the Moorpark sub-area analysis can be found in the CAISO's 2014-2015 transmission plan, Appendix E.[1] The relevant portions of Appendix E are included as Exhibit 1 to my testimony.

Q. Please explain the results of the CAISO's 2014-2015 transmission plan local capacity requirement analysis for the Moorpark sub-area.

A. The CAISO identified the most critical contingency in the Moorpark sub-area as the loss of the Moorpark-Pardee 230 kV #3 line followed by the loss of the Moorpark-Pardee 230 kV #1 and #2 lines, which would cause voltage collapse. The local capacity requirement analysis conducted in the 2014-2015 transmission plan indicates that the selected RFO resources meet this identified reliability constraint and are sufficient to meet the local reliability needs in the Moorpark sub-area through 2024, based on the assumptions in the transmission plan.[2]

Most notably, the 2014-2015 transmission plan assumes that 87 MW of additional achievable energy efficiency will materialize in the Moorpark sub-area by 2024, in addition to the 6 MW of energy efficiency included in the present Application

Q. Based on the results of the CAISO's analysis, will the resources selected in SCE's 2013 RFO enhance the reliability of SCE's electrical service?

A. Yes, the resources selected in SCE's 2013 RFO will enhance the reliability of SCE's electrical service starting in 2021 time frame. However, as discussed above, the resources for which SCE requests approval in this proceeding are only a portion of

[1] http://www.caiso.com/Documents/AppendixEBoardApproved2014-2015TransmissionPlan.pdf.

[2] In Track 1 of the 2012 long-term procurement plan the CAISO identified a total need in the Moorpark sub-area of 430 MW. In the most recent CAISO analysis, the new resources in SCE's application combined with an assumed incremental additional achievable energy efficiency total 361 MW, but are sufficient to meet long-term reliability needs in the Moorpark sub-area. The reduction in identified long-term need is primarily due to updates in the SCE system modeling that result in better representation of switching and utilization of existing static reactive support in the Moorpark sub-area and the surrounding area between the transient and post-transient time frame.

those necessary to meet reliability needs in the Moorpark sub-area. To ensure reliability, the Commission must continue to monitor the development and implementation of other local resources including additional achievable energy efficiency.

Q. Please summarize your testimony.

A. The results of SCE's 2013 Moorpark RFO are consistent with the CAISO's planning assumptions in the 2014-2015 transmission plan. The resources selected in the RFO meet the minimum procurement requirements set forth in the Commission's Track 1 long-term procurement plan decisions, and they are effective and necessary to meet long-term reliability needs as demonstrated by the CAISO's analyses. Overall, if approved by the Commission and implemented in a timely manner, the RFO resources will enhance the reliability of SCE's electrical service.

Q. Does this conclude your testimony?

A. Yes, it does.

EXHIBIT 1

APPENDIX E: 2024 Local Capacity Technical Analysis

24309	B CRK2-2	4	24
24310	B CRK2-3	5	24
24310	B CRK2-3	6	24
24315	B CRK 8	81	24
24315	B CRK 8	82	24
24323	PORTAL	1	24
24311	B CRK3-1	1	23
24311	B CRK3-1	2	23
24312	B CRK3-2	3	23
24312	B CRK3-2	4	23
24313	B CRK3-3	5	23
24317	MAMOTH1G	1	23
24318	MAMOTH2G	2	23
24314	B CRK 4	41	22
24314	B CRK 4	42	22

Santa Clara Sub-area:

The most critical contingency is the loss of the Pardee - Santa Clara 230 kV line followed by the loss of Moorpark - Santa Clara 230 kV #1 and #2 lines, which would cause voltage collapse. This limiting contingency establishes a local capacity need of 277 MW (includes 68 MW QF generation as well as 30 MW of deficiency) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Due to upcoming OTC compliance dates the use of 29 MW of AAEE and LTPP EE assumed in this study is critical, without it the LCR need will be higher by about the same amount.

Effectiveness factors:

All units within this area have the same effectiveness factor.

Moorpark Sub-area:

The most critical contingency is the loss of the Moorpark - Pardee 230 kV #3 line followed by the loss of the Moorpark - Pardee 230 kV #1 and #2 lines, which will cause voltage collapse. This limiting contingency establishes a local capacity need of 512 MW (includes 97 MW QF generation as well as 230 MW of deficiency) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Due to upcoming OTC compliance dates the use of 93 MW of AAEE and LTPP EE assumed in this study is critical, without it the LCR need will be higher by about the same amount.

Effectiveness factors:

All units within this area have the same effectiveness factor.

Big Creek/Ventura overall:

The most critical contingency is the loss of the Lugo - Victorville 500 kV line followed by loss of one of the Sylmar - Pardee 230 kV line, which would thermally overload the remaining Sylmar - Pardee 230 kV line. This limiting contingency establishes a local capacity need of 2,783 MW (includes 769 MW of QF and 392 MW of MUNI generation) as the minimum capacity necessary for reliable load serving capability within this area.

The single most critical contingency is the loss of Sylmar - Pardee #1 (or # 2) line with Pastoria power plant (CCGT) out of service, which could thermally overload the remaining Sylmar - Pardee #1 or #2 230 kV line. This limiting contingency establishes a Local Capacity Need of 2,603 MW (includes 769 MW of QF and 392 MW of MUNI generation).

Due to upcoming OTC compliance dates the use of 317 MW of AAEE and LTPP EE assumed in this study is critical, without it the LCR need will be higher by about the same amount.

Effectiveness factors:

The following table has effectiveness factors to the most critical contingency.

Gen Bus	Gen Name	Ck	Eff Factor (%)
24108	ORMOND2G	1	40
24010	APPGEN2G	1	39
24148	TENNGEN1	1	39

24149	TENNGEN2	1	39
24009	APPGEN1G	1	38
24107	ORMOND1G	1	38
24118	PITCHGEN	1	38
24361	APPGEN3G	1	38
25651	WARNE1	1	37
25652	WARNE2	1	37
24089	MANDLY1G	1	36
24090	MANDLY2G	1	36
24127	S.CLARA	1	36
29004	ELLWOOD	1	36
24110	OXGEN	1	36
24119	PROCGEN	1	36
24159	WILLAMET	1	36
24340	CHARMIN	1	36
29952	CAMGEN	1	36
24362	EXGEN2	1	36
24326	EXGEN1	1	36
24362	EXGEN2	1	36
24222	MANDLY3G	1	35
25614	OSO A P	1	35
25614	OSO A P	1	35
25615	OSO B P	1	35
25615	OSO B P	1	35
29306	MCGPKGEN	1	35
29055	PSTRIAS2	1	34
29054	PSTRIAG3	1	34
29053	PSTRIAS1	1	34
29052	PSTRIAG2	1	34
29051	PSTRIAG1	1	34
25605	EDMON1AP	1	34
25606	EDMON2AP	1	34
25607	EDMON3AP	1	34
25607	EDMON3AP	1	34
25608	EDMON4AP	1	34
25608	EDMON4AP	1	34
25609	EDMON5AP	1	34
25609	EDMON5AP	1	34
25610	EDMON6AP	1	34
25610	EDMON6AP	1	34
25611	EDMON7AP	1	34
25611	EDMON7AP	1	34
25612	EDMON8AP	1	34

25612	EDMON8AP	1	34
25653	ALAMO SC	1	34
24370	KAWGEN	1	32
24113	PANDOL	1	31
24113	PANDOL	1	31
29008	LAKEGEN	1	31
24150	ULTRAGEN	1	31
24152	VESTAL	1	31
24307	B CRK1-2	1	31
24307	B CRK1-2	1	31
24308	B CRK2-1	1	31
24308	B CRK2-1	1	31
24309	B CRK2-2	1	31
24309	B CRK2-2	1	31
24310	B CRK2-3	1	31
24310	B CRK2-3	1	31
24311	B CRK3-1	1	31
24311	B CRK3-1	1	31
24312	B CRK3-2	1	31
24312	B CRK3-2	1	31
24313	B CRK3-3	1	31
24314	B CRK 4	1	31
24314	B CRK 4	1	31
24315	B CRK 8	1	31
24315	B CRK 8	1	31
24317	MAMOTH1G	1	31
24318	MAMOTH2G	1	31
24372	KR 3-1	1	31
24373	KR 3-2	1	31
24102	OMAR 1G	1	30
24103	OMAR 2G	1	30
24104	OMAR 3G	1	30
24105	OMAR 4G	1	30
24143	SYCCYN1G	1	30
24144	SYCCYN2G	1	30
24145	SYCCYN3G	1	30
24146	SYCCYN4G	1	30
24319	EASTWOOD	1	30
24306	B CRK1-1	1	30
24306	B CRK1-1	1	30
24136	SEAWEST	1	9
24437	KERNRVR	1	8

Changes compared to the 2019 results:

The load forecast went up by 108 MW and the LCR need has increased by 164 MW.

The AAEE and LTPP EE remain critical for the Santa Clara and Moorpark sub-areas.

Big Creek/Ventura Overall Requirements:

2024 LTPP Assumptions	LTPP EE (MW)	Solar PV (MW)	Storage 4h (MW)	Conventional resources (MW)	LTPP Total Capacity (MW)
SCE-submitted procurement selection	6	6	1	262	275

2024	QF (MW)	Muni (MW)	Market (MW)	New DG (MW)	Max. Qualifying Capacity (MW)
Available generation	769	392	2258	248	3667

2024	Total MW Requirement	Existing Resource Need (MW)	Deficiency without LTPP T1 & T4 (MW)	Total SCE Selected Procurement for LTPP Tracks 1 & 4 (MW)
Category B (Single)[33]	2,603	2,603	0	275
Category C (Multiple)[34]	2,783	2,553	230	275

10. San Diego-Imperial Valley Area

<u>Area Definition</u>

The transmission tie lines forming a boundary around the San Diego-Imperial Valley area include:

1) Imperial Valley – North Gila 500 kV Line
2) Otay Mesa – Tijuana 230 kV Line
3) San Onofre - San Luis Rey #1 230 kV Line
4) San Onofre - San Luis Rey #2 230 kV Line

[33] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

[34] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

EXHIBIT G

Application No.: 14-11-016
Exhibit No.: ________________
Witness: ________________

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.	Application 14-11-016

TESTIMONY OF NEIL MILLAR
ON BEHALF OF THE
CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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.	Application 14-11-016

TESTIMONY OF NEIL MILLAR ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

Q. What is your name and by whom are you employed?

A. My name is Neil Millar. I am employed by the California Independent System Operator Corporation (CAISO), 250 Outcropping Way, Folsom, California as the Executive Director, Infrastructure Development.

Q. Please describe your educational and professional background.

A. I received a Bachelor of Science in Electrical Engineering degree at the University of Saskatchewan, Canada, and am a registered professional engineer in the province of Alberta.

I have been employed for over 30 years in the electricity industry, primarily with a major Canadian investor-owned utility, TransAlta Utilities, and with the Alberta Electric System Operator and its predecessor organizations. Within those organizations, I have held management and executive roles responsible for preparing, overseeing, and providing testimony for numerous transmission planning and regulatory tariff applications. I have appeared before the Alberta Energy and Utilities Board, the Alberta Utilities Commission, and the British Columbia Utilities Commission. Since November, 2010, I have been employed at the ISO, leading the Transmission Planning and Grid Asset departments.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of how Southern California Edison Company's (SCE) 2013 request for offers (RFO) meets the local capacity requirement needs for the Moorpark sub-area as identified in Commission Decision (D.) 13-02-015 (Track 1 Decision). My testimony addresses the following issues set forth in the Assigned Commissioner's Ruling and Scoping Memo issued March 13, 2015:

1. Whether the results of SCE's 2013 LCR RFO for the Moorpark sub-area enhance the safe and reliable operation of SCE's electrical service; and
2. Whether the results of SCE's 2013 LCR RFO for the Moorpark sub-area are a reasonable means to meet the 215 to 290 megawatts (MW) of identified LCR need determined by D.13-02-015.

Q. What are your recommendations in this proceeding?

A. I recommend that the Commission:

1. Approve the results of SCE's 2013 RFO for the Moorpark sub-area;
2. Find that the results of SCE's 2013 LCR RFO for the Moorpark sub-area enhance the reliable operation of SCE's electrical service; and
3. Find that the results of SCE's 2013 RFO for the Moorpark sub-area represent a reasonable means to meet a portion of the identified local capacity requirement need determined in D.13-02-015.

These recommendations are discussed in detail below.

Q. Please describe how SCE's RFO-selected resources align with the Track 1 long-term procurement plan decision of the Commission.

A. The Commission's Track 1 Decision recognized an "immediate need" for capacity in the Moorpark sub-area and authorized SCE to procure a minimum of 215 MW to a maximum of 290 MW of capacity.[1] Although the CAISO asserted that there was a need for 430 MW of new capacity in the Moorpark sub-area, the Commission authorized procurement of up to only 290 MW after noting that preferred resources and possible transmission solutions could lead to a reduction in need for new capacity.[2] The Track 1 Decision recognized the "operational benefits from having specific types of in-area generation with the characteristics of the current [once-through-cooling] plants for the Moorpark area" and noted that local capacity requirements "require resources be located in a specific transmission-constrained area in order to ensure adequate available electrical capacity to meet peak demand, and ensure the safety and reliability of the local electrical grid."[3] Consistent with the Commission's decision, SCE's Application requests approval to procure resources totaling approximately 274 MW of capacity in the Moorpark sub-area.

In Section 7.3.2 of the Track 1 Decision, the Commission set forth minimum requirements for resources to be considered in SCE's RFO. The Commission stated that the RFO should be limited to resources that (1) meet the identified reliability constraint identified by the CAISO, (2) are demonstrably incremental to the assumptions used in the CAISO studies, and (3) offer the performance characteristics needed to be eligible to count as local RA capacity. Based on the CAISO's review, the resources selected in SCE's RFO meet these criteria.

Q. Please describe the consultations between the CAISO and SCE regarding requirements for resources considered in the 2013 SCE RFO.

A. The CAISO worked with SCE to confirm that the location and characteristics of the procured resources would meet the local capacity needs. During the pendency of 2014-2015 transmission planning process, SCE provided the CAISO with a procurement scenario based on the actual RFO-selected resources for the Moorpark

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[1] D.13-02-015, p. 125.
[2] *Id.*, p. 72.
[3] *Id.*, p. 2.

sub-area. The CAISO studied this scenario to determine that RFO-selected resources meet the identified local capacity requirement needs.

The CAISO also informed SCE that demand response and non-dispatchable resources must have a fixed operational period of four hours for qualified capacity valuation calculations set by the Commission.[4] Resources that do not meet the Commission's minimum standards for qualifying capacity are not capable of receiving system resource adequacy credit.

These consultations were conducted according to the Commission's directive in the Track 1 long-term procurement plan decision to "meet the identified reliability constraint identified by the CAISO" and "use the most up-to-date effectiveness ratings."[5]

Q. Are the results of SCE's Moorpark sub-area RFO consistent with the Track 1 Decision?

A. Yes, SCE's request to procure resources totaling approximately 274 MW of capacity is within the range of the Commission's Track 1 decisions authorized procurement of a minimum of 215 MW and a maximum of 290 MW of capacity.

The CAISO has analyzed the results of SCE's RFO in the context of the 2014-2015 transmission plan which was presented to the CAISO Board of Governors and approved on March 26. These results indicate that the proposed RFO procurement can meet long-term local capacity requirement needs when combined with the California Energy Commission's forecast of 87 MW of additional achievable energy efficiency for the Moorpark subarea. The Commission must continue to monitor

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[4] *See* the Commission's 2015 Filing Guide for System, Local and Flexible Resource Adequacy (RA) Compliance Filings, issued September 9, 2015. http://www.cpuc.ca.gov/NR/rdonlyres/70C64A46-89DE-4D90-83AB-93FD840B4251/0/Final2015RAGuide.docx.

[5] D.13-02-015 at 131-132.

the development of these resources in order to ensure the long-term reliability of the system.

Mr. Sparks' concurrently served testimony provides additional detail regarding the results of the CAISO's 2014-2015 transmission plan and the local capacity requirement analysis conducted for the Moorpark subarea.

Q. Please summarize your recommendations.

A. The CAISO's local capacity requirement analysis shows that the RFO resources will enhance the reliable operation of SCE's electrical service. Based on location and operational characteristics, the RFO-selected resources represent a reasonable means to meet a portion of the local capacity requirement determined in D.13-02-015. As a result, I recommend that the Commission approve the results of SCE's 2013 LCR RFO for the LA Basin.

Q. Does this conclude your testimony?

A. Yes, it does.

EXHIBIT H

L/rar

Date of Issuance
December 5, 2016

Decision 16-12-030 December 1, 2016

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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.	Application 14-11-016 (Filed November 26, 2014)

ORDER MODIFYING DECISION (D.) 16-05-050 AND DENYING REHEARING, AS MODIFIED

I. INTRODUCTION

In this Order, we dispose of the applications for rehearing of Decision (D.) 16-05-050 (or "Decision") filed by the City of Oxnard ("Oxnard"), California Environmental Justice Alliance ("CEJA") and Sierra Club (jointly), and Center for Biological Diversity ("Center").

In 2013, the Commission issued what is referred to as the *Track 1 Decision* in the Long-Term Procurement Plan ("LTPP") proceeding. That decision authorized Southern California Edison Company ("SCE") to meet its local reliability/capacity needs by issuing a Request for Offers ("RFO") in both the West Los Angeles sub-area of Los Angeles, and the Moorpark sub-area of Big Creek/Ventura ("Moorpark").[1] The rehearing applications at issue in this Order pertain to the Moorpark solicitation. In

[1] *Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans* (R.12-03-014) [D.13-02-015] ("*Track 1 Decision*") (2013) at pp. 1-4, 130-131 [Ordering Paragraph Numbers 1 & 2] (slip op.). One RFO was issued covering both sub-areas.

All citations to Commission decisions are to the official pdf versions which are available on the Commission's website at: http://docs.cpuc.ca.gov/DecisionsSearchForm.aspx.

Moorpark, SCE was authorized to procure 215-290 megawatts ("MW") of non-resource specific electric capacity to meet local capacity requirements by 2021.[2]

The challenged Decision (D.16-05-050) approved 12 MW of preferred resource load reduction contracts with energy efficiency and solar generation projects.[3] It also approved a 20-year power purchase contract with NRG Energy Center Oxnard LLC ("NRG") for the Puente Project, a 262 MW natural gas-fired peaker facility.

Timely applications for rehearing were filed by the Oxnard, CEJA and Sierra Club (jointly), and the Center.

Oxnard argues that we should have acted as the lead agency under the California Environmental Quality Act ("CEQA") to conduct environmental review before approving the Puente contract.

CEJA and Sierra Club allege the Decision erred in approving the Puente contract because it: (1) failed to adequately consider environmental justice issues; (2) failed to comply with Government Code sections 65040.12(e) and 11135; (3) relied on a procurement plan approved by the Energy Division; (4) approved the contract before environmental review by the California Energy Commission ("CEC") was complete;[4] and (5) failed to adequately apply least-cost best-fit procurement criteria.

Center contends the Decision erred in approving the Puente contract because it: (1) is contrary to the preferred resources Loading Order; (2) approved the contract before environmental review was complete; (3) was tainted by a biased RFO; and (4) failed to assess project need. The Center also requests oral argument.

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[2] *Track 1 Decision* [D.13-02-015], *supra*, at p. 2, 131 [Ordering Paragraph Number 2] (slip op.).

[3] D.16-05-050, at pp. 1, 38 [Ordering Paragraph Numbers 7, 10 & 11].

[4] Pursuant to Public Resources Code sections 25500 – 25542, the CEC has exclusive jurisdiction to certify the construction and operation of all thermal electric power plants 50 MW or larger. Thus, as discussed elsewhere in this order, the CEC is the lead agency for environmental review of the Puente Project.

SCE filed a public response and a motion for leave to file a confidential response. It is not necessary to grant SCE's motion because its public response already identifies where in the record the confidential information it relies on can be found. That information is readily accessible, and already has confidential status under seal. Therefore, the confidential response is not necessary to thoroughly consider SCE's positions.

We have carefully considered the arguments raised in the applications for rehearing and are of the opinion that good cause has not been established to grant rehearing. However, as set forth in the blow ordering paragraphs, we modify D.16-05-050 to clarify our discussion regarding consideration of environmental justice issues, and add and/or modify certain findings of fact and conclusions of law for clarity. With these clarifications we deny the applications for rehearing of D.16-05-050, as modified, because no legal error was shown.

II. DISCUSSION

A. City of Oxnard Application for Rehearing

Oxnard's application for rehearing does not meet the statutory criteria for a permissible application for rehearing. Pursuant to Public Utilities Code section 1732, applications for rehearing must "set forth specifically the ground or grounds on which the applicant considers the decision or order to be unlawful."[5] The purpose for requiring specific and supported claims is to "alert the Commission to legal error, so that the Commission can correct it…." It is not sufficient for a party to just identify broad legal principles, or make general statements and arguments. The rehearing application must

[5] Pub. Util. Code, § 1732; see also Rule 16.1, subd. (c) of the Commission's Rules of Practice and Procedure (Cal. Code of Regs., tit. 20, § 16.1, subd. (c).). All subsequent section references are to the Public Utilities Code unless otherwise specified.

explain how the law and its arguments apply to the case and facts in question.[6]

Oxnard did not do this. It submitted a cursory one page rehearing application purporting to join in certain arguments raised by CEJA and Sierra Club, and summarily asserting the Commission should have conducted CEQA review before approving the Puente contract.[7] (Oxnard Rhg. App., at p. 1.)

Section 1732 does not contemplate nor allow a rehearing applicant to simply piggyback on arguments raised by other parties. A party must submit its own stand-alone document that meets the requirement stated in section 1732. Because Oxnard failed to do this, we reject its application for rehearing.

B. CEJA and Sierra Club Application for Rehearing

1. Environmental Justice

a. Procurement Criteria

If certified, the Puente Project will be located in the City of Oxnard. Oxnard is designated as an environmentally disadvantaged community by the California Environmental Protection Agency.[8]

CEJA and Sierra Club contend that we failed to adequately consider environmental justice issues in approving the Puente contract, because the Decision found that past decisions have not provided sufficient guidance about how this issue should be considered. (CEJA/Sierra Club Rhg. App., at pp. 6-8, citing *Order Instituting Rulemaking to Integrate Procurement Policies and Consider Long-Term Procurement*

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[6] See, e.g., *Application of Channel Islands Telephone Company for Rehearing of Portion of Resolution T-17402 Affirming the Rejection of Resolution T-17382 that Resulted in the Denial of the Rural Telecommunication Infrastructure Grant Program Request for the Channel Islands Telephone Company Grant Project* [D.14-06-054] (2014) at pp. 3-4 (slip op.).

[7] Oxnard also cites to a brief it filed earlier in this proceeding, presumably to incorporate by reference all or some of the arguments previously made in the proceeding. Citing to past pleadings as a substitute for presenting thoroughly articulated factual and legal arguments in a rehearing application does not comply with section 1732. It also inappropriately shifts the burden to the Commission to determine what exact arguments a rehearing applicant intended to make. Thus, such attempts are rejected.

[8] See D.16-05-050, at p. 15, citing CalEnviroScreen 2.0.

Plans [D.07-12-052] (2007), at p. 157 (slip op.).) As discussed below, we will modify the Decision to clarify our discussion of environmental justice. However, in view of other factors warranting contract approval, we find no legal error.

The Puente Project will be sited on a brownfield site where the Mandalay Generating Station is currently located. Commission policy directs utilities to take advantage of brownfield sites, stating:

> *IOUs are to consider the use of Brownfield sites first* and take full advantage of their location before they consider building new generation on Greenfield sites. If IOUs decide *not to use Brownfield, they must make a showing that justifies their decision….*

(D.07-12-052, *supra*, at p. 307 [Ordering Paragraph Number 35] (slip op.) (emphasis added.).)

We are aware this contract did raise environmental justice issues, but that is only one factor to be considered in making procurement selections. Procurement evaluations must also take into account: capacity and energy benefits; resource diversity; portfolio fit; local reliability/resource adequacy; congestion costs; credit and collateral; environmental impacts/benefits (including Greenfield vs. Brownfield development); debt equivalence; and transmission costs/savings.[9]

CEJA and Sierra Club are silent on these issues, and the evidence in the record regarding these factors did support contract approval.[10] It was also beneficial that the Puente Project will be a reliable peaker plant with fast-start, fast ramping capabilities which provide important grid support services.[11] Overall, the contract's economics and general terms and conditions were found to represent the best resource available from the RFO, and the energy is needed to meet local reliability needs in Moorpark given pending

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[9] D.07-12-052, *supra*, at pp. 155-157 (slip op.).

[10] D.16-05-050, at p. 9. See also Exh. SCE-2, Appendix D, Independent Evaluator Report, at pp. 4-9, 18-22, 37-39, Appendix A to Appendix D, Independent Evaluator Report, at pp. A-1 to A-8.

[11] D.16-05-050, at p. 9.

retirement of Mandalay Units 1 and 2, and the Ormond Beach once-through cooling ("OTC") generation units.[12] Thus, on balance, it was reasonable to approve the Puente contract.

There is, however, some merit to CEJA and Sierra Club's criticism that the Decision erred in characterizing the discussion of environmental justice in D.07-12-052 as "dicta." (CEJA/Sierra Club Rhg. App., at pp. 6-8, citing the Energy Division's 2010 Procurement Policy Manual, at pp. 4-8 to 4-9.)[13]

Even if prior procurement decisions have provided little guidance regarding the consideration of this issue, D.07-12-052 did not suggest it is any less (or more) important than other procurement criteria.[14] Therefore, to help clarify the role of how environmental justice issues should be considered in future procurement applications, we will modify the Decision as set forth in the below ordering paragraphs.

b. Public Utilities Code 399.13(a)(7)

Section 399.13 is part of the California Renewables Portfolio Standard ("RPS") Program and requires, among other things, that in procuring renewable energy resources, the utilities:

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[12] D.16-05-050, at pp. 24-25, 36 [Finding of Fact Numbers 9 & 13].

[13] The Procurement Policy Manual can be located at: http://docs.cpuc.ca.gov/efile/RULINGS/118826.pdf.

[14] Furthermore, in D.16-05-050 we balanced the factors necessary to any procurement decision. As stated in D.07-12-052:

> We discuss below certain bid evaluation metrics that we urge the utilities, in conjunction with Independent Evaluators, Procurement Review Groups and Energy Division, to consider when developing the RFO bid documents and process….We agree with the IOUs that it may prove counterproductive to be too prescriptive in identifying specific RFO bid evaluation criteria. A 'one-size-fits-all' approach may not be achievable and, therefore, may not truly 'fit all.' However, we are concerned that the other extreme – allowing the IOUs too much leeway in determining the criteria…is also problematic….the IOU must be able to fully justify why a particular project wins a solicitation, and *we provide here some general guidance as to the IOUs regarding the types of evaluation criteria that should be applied*….

(D.07-12-052, *supra*, at pp. 155-156 (slip op.) (emphasis added.).)

> …give preference to renewable energy projects that provide environmental and economic benefits to communities afflicted with poverty or high unemployment, or that suffer from high emission levels of toxic air contaminants, criteria air pollutants, and greenhouse gasses.

(Pub. Util. Code, § 399.13, subd. (a)(7).)

CEJA and Sierra Club concede that gas-fired generation is not subject to RPS requirements. But they argue the Decision should have applied the statute anyway, and erred in stating the statute does not apply to all-source procurement contracts. (CEJA/Sierra Club Rhg. App., at pp. 8-9.)

The Decision did not engage in a broad discussion of all-source contracts. It said only that the plain language of the statute pertains only to review of renewables procurement, which the Puente contract was not.[15]

2. Government Code Sections 65040.12(e) and 11135

CEJA and Sierra Club contend that approval of the Puente contract violated Government Code sections 65040.12(e) and 11135, and the Commission ignored those statutory requirements. (CEJA/Sierra Club Rhg. App., at pp. 9-10.)

In relevant part, Government Code Section 65040.12 provides:

> (e) For purposes of this section, "environmental justice" means the fair treatment people of all races, cultures, and incomes with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations, and policies.

(Gov. Code, § 65040.12, subd. (e).)

In addition, Government Code section 11135 provides:

> (a) No person in the State of California shall, on the basis of race, national origin, ethnic group identification, religion, age, sex, sexual orientation, color, genetic information, or disability, be unlawfully denied full and equal access to

[15] D.16-05-050, at p. 17.

> the benefits of, or be unlawfully subjected to discrimination under, any program or activity that is conducted, operated, or administered by the state or any state agency, is funded directly by the state, or receives any financial assistance from the state….

(Gov. Code, § 11135.)

We agree these provisions reflect State environmental justice and anti-discrimination policies. However, CEJA and Sierra Club do not establish how these statutes apply to Commission energy procurement proceedings.

Government Code section 65040.12 applies to the Office of Planning and Research ("OPR") in connection with its planning and research functions.[16] It imposes no requirements on this Commission.

Government Code section 11135 is a general anti-discrimination statute applicable to California State Agencies.[17] But CEJA and Sierra Club fail to explain or establish how the Puente contract would constitute discrimination within the meaning of that statute. Accordingly, we find no legal error.

3. Procurement Plan Approval

a. Delegation to Staff

The *Track 1 Decision* directed SCE to submit its procurement plan to the Energy Division for approval before SCE could begin the Moorpark and Western LA Basin solicitations.[18]

CEJA and Sierra Club contend this was an unlawful delegation of Commission authority. They argue consistent with *Southern California Edison Company v. Public Utilities Commission* ("*SCE v. PUC*") (2014) 227 Cal.App.4th 172, 195-196, the

[16] Gov. Code, Title 7. Planning and Land Use [65000-66499.58], Division 1. Planning and Zoning [65000-66103], Chapter 1.5 Office of Planning and Research [65025-65059].

[17] Gov. Code Title 2. Government of the State of California [8000-22980], Division 3. Executive Department [11000-15986], Part 1. State Departments and Agencies [11000-11894], Chapter 1. State Agencies [11000-11148.5.].

[18] *Track 1 Decision* [D.13-02-015], *supra*, at pp. 89-90 (slip op.).

Commission was required to review and approve the plan itself. (CEJA/Sierra Club Rhg. App., at pp. 11-14.)

We find no violation of *SCE v. PUC*. Consistent with that decision we exercised and retained all policymaking power (i.e. discretionary power) over the terms, conditions and requirements for SCE's procurement plan. Nothing in our decision delegated such power to Energy Division. For example, in the *Track 1 Decision* we directed that SCE's plan must conform with all previously adopted procurement rules as established in D.07-12-052 and elsewhere.[19] And we explicitly enumerated many of the requirements the plan must satisfy.[20]

Having done that, subsequent Energy Division approval was a ministerial compliance task. Energy Division was not called upon to exercise its own judgment or discretion to determine what SCE's plan should include.[21]

We also point out that CEJA and Sierra Club's challenge of the review process at this juncture is untimely. The process was developed and adopted in the Track 1 proceeding. CEJA and Sierra Club were parties to that proceeding and had they believed the review process was unlawful, the proper time to object was during that proceeding and/or in an application for rehearing of the *Track 1 Decision*. They did not and D.13-02-015 is now final. Thus, lawful challenge of that decision is now precluded by sections 1709 and 1731(b), and cannot be impermissibly used as a means to invalidate D.16-05-050.[22]

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[19] *Track 1 Decision* [D.13-02-015], *supra*, at p. 90 (slip op.). See also D.07-12-052, *supra,* approving the long-term procurement plans of Pacific Gas and Electric Company, SCE, and San Diego Gas & Electric Company for the 2007-2016 time period.

[20] *Track 1 Decision* [D.13-02-015], *supra*, at pp. 90-92, 130-134 [Ordering Paragraph Numbers 1-7] (slip op.).

[21] *Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans* [D.14-08-08] at pp. 6-7.

D.16-05-050, at p. 37 [Conclusion of Law Number 1].

[22] See also *Coast Truck Line v. Asbury Truck Co.* (1933) 218 Cal. 337, 340.

CEJA and Sierra Club also contest how we characterized the purpose of this proceeding. The Decision stated the goal of this proceeding was to determine whether SCE followed its procurement plan, not to determine whether the underlying plan itself was adequate. CEJA and Sierra Club quote the following language from D.14-08-008 to argue that was wrong:

> Approval of SDG&E's procurement plans by Energy Division, once they are deemed to be consistent with D.14-03-004, does not infringe on the due process rights of parties to contest any specific procurement contracts or methods proposed by SDG&E in forthcoming applications.

(*Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans* [D.14-08-008] (2014) at p. 11 (slip op.).)

Based on this language, CEJA and Sierra Club assert it was irrelevant to determine whether SCE followed its procurement plan, because that would not show the procurement process was legitimate or that the Puente contract was reasonable. We do not agree these issues can be so finely parsed.

Combined, decisions such as D.07-12-052 and the *Track 1 Decision* reflect procurement plan requirements to ensure that utility solicitations will reflect the State's energy policies, will ensure a legitimate, fair and open solicitation process, and will result in contracts that comply with the established requirements.[23]

Here, SCE's plan was subject to all Commission adopted procurement rules and RFO requirements.[24] Those included not only the specific substantive requirements set out in the *Track 1 Decision*, but the requirements in D.07-12-052 and other decisions concerning the RFO process, Peer Review Group coordination, Independent Evaluator review, bid evaluation, and transparency, etc.[25]

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[23] See also, e.g., *Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans* ("*Track 4 Decision*") [D.14-03-004].

[24] *Track 1 Decision* [D.13-02-015], *supra,* at p. 90, fn. 230 (slip op.).

[25] D.07-12-052, *supra,* at pp. 119-167 (slip op.).

While we may not approve all contracts that result from an RFO, when a utility ultimately seeks approval of its solicitation results, establishing compliance with an approved procurement plan is generally a fairly reasonable measure that a solicitation was legitimate and the proposed contracts are reasonable.

Additionally, the requirements for SCE's procurement plan were litigated and determined in the *Track 1 Decision.* If CEJA and Sierra Club believed those requirements would result in an inadequate plan, they should have contested the *Track 1 Decision.* Here, having determined that SCE's solicitation substantially complied with the procurement requirements, it was past the time to revisit the adequacy of the requirements or the plan. The task was to determine the merits of each proposed contract, and whether SCE properly implemented its procurement plan and its requirements.

b. Due Process

Due process requires the Commission to ensure that parties receive adequate notice and opportunity to be heard.[26] CEJA and Sierra Club contend they did not have that here, alleging the procurement plan was developed through a confidential process. They assert that their first opportunity to evaluate the plan's "contents" was in this proceeding. (CEJA/Sierra Club Rhg. App., at pp. 10, 13-14.)

Although CEJA and Sierra Club do not define what they mean by"contents," for practical purposes, the "contents" of a plan would identify how the utility would implement and achieve the requirements set out in the *Track 1 Decision.* As stated above, the solicitation requirements ("contents") were publically litigated and prescribed during the *Track 1 Decision* process.[27] CEJA and Sierra Club had notice and

[26] See, e.g., *Railroad Commission of California v. Pacific Gas and Electric Company* (1937) 302 U.S. 388, 393; *People v. Western Air Lines, Inc.* (1954) 52 Cal.2d 621, 632.

[27] *Track 1 Decision* [D.13-02-015], *supra*, at pp. 89-92, 130-136 [Ordering Paragraph Numbers 1-15] (slip op.).

availed themselves of the opportunity to review and participate in developing the plan's "contents."

Ultimately, however, it is for the Commission to approve a utility's procurement plan consistent with the requirements that have been established.[28] That approval does not equate to a confidential process as CEJA and Sierra Club suggest. As explained above, once the "contents" had been established, Energy Division review was a compliance check.[29]

CEJA and Sierra Club disagree, arguing the *Track 1 Decision* gave SCE flexibility to independently develop its plan.[30] CEJA and Sierra Club either misinterpret or misrepresent what the *Track 1 Decision* stated. It said:

> SCE seeks flexibility to choose the exact circumstances and timing under which it would utilize an RFO or bilateral contract negotiation in its LCR solicitation process....We agree with SCE that it is difficult in advance to know which method would be most advantageous to ratepayers….We will allow SCE the flexibility it seeks, subject to review of its procurement plan by Energy Division and a subsequent Commission application.

Track 1 Decision [D.13-02-015], *supra*, at pp. 89-90 (slip op.).)

Allowing flexibility as to the circumstances and timing for the RFO is not the same as giving SCE flexibility to determine the plan's substantive requirements. And nothing in the *Track 1 Decision* gave SCE the flexibility to change or eliminate those.

Further, in this proceeding parties did have notice and opportunity to comment on whether the RFO process was properly implemented, and whether the

[28] Pub. Util. Code, § 454.5, subd. (a).

[29] CEJA and Sierra Club suggest public review and comment was also required at that juncture. But they offer no legal authority requiring multiple levels of public review, and/or particularly a requirement for public review at the compliance filing juncture. That is appropriately an agency function.

[30] CEJA and Sierra Club also cite Commission Rule of Practice and Procedure 2.6 to argue when deciding an application, the Commission must allow for participation. Rule 2.6 allows for protests, responses and replies to formal applications. CEJA and Sierra Club were not denied that process here.

proposed contracts merited approval. CEJA and Sierra Club may disagree with our conclusions, but that is not grounds for legal error.[31]

4. Environmental Review

Because the CEC has exclusive jurisdiction to certify the construction and operation of all thermal electric power plants 50 MW or larger, CEC is the "lead agency" for Puente Project CEQA review.[32] CEJA and Sierra Club argue the Commission was required to act as a "responsible agency" and await completion of CEC's review before approving the Puente contract. (CEJA/Sierra Club Rhg. App., at pp. 14-15.)

We have considered this issue on several occasions and found no legal requirement to conduct CEQA review in connection with review and approval of power purchase contracts.[33] CEQA defines a "project" as "activities" involving the issuance of a lease, permit, license, certificate, or other entitlement for use by one or more public agencies.[34] We agree certification and construction of the Puente generating facility is a "project" for purposes of CEQA.

However, the Commission does not act as "responsible agency" in approving an energy contract with such a facility. CEQA defines a "responsible agency" as a public agency other than the lead agency which has discretionary approval over the project."[35] We have no discretionary power to approve or deny any aspect of the

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[31] *Southern California Edison Company v. Public Utilities Commission* (2005) 128 Cal. App. 4th 1, 8.

[32] Pub. Resources Code, §§ 25500-25542. CEC licensing is considered a certified regulatory program under CEQA, and the functional equivalent of preparing an environmental impact report ("EIR"). (See, e.g., CEC Energy Facility Licensing Process Staff Report, dated November 2000, located at: http://www.energy.ca.gov/siting/guide_license_process.html.)

[33] See, e.g., *Application of San Diego Gas & Electric Company (U902E) 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* [D.15-05-051] (2015) at pp. 29-31 (slip op.), as modified by D.15-11-024 (2015), at pp. 2-5 (slip op.).
fn. 5 (slip op.).

[34] Pub. Resources Code, § 21065.

[35] Pub. Resources Code, § 21069.

certification or construction of the Puente Project. Nor do we have any jurisdiction over the project proponent (NRG).

Our involvement is limited to the utility's request to procure power from the Puente facility *if* it is ultimately certified and constructed. Our approval confers no lease, permit, license, certificate, or other entitlement on NRG. It means only that should the project become operational, SCE may take energy deliveries from that resource and recover certain costs in rates.

CEJA and Sierra Club counter that contract approval virtually guarantees the facility will be certified, thus we effectively have discretionary approval.[36] (Rhg. App., at p. 14, citing RT Vol. 2, NRG/Gleiter, at pp. 336-337.)

Even if contract approval were to improve the overall risk profile for a developer, many more factors go into whether a project ultimately comes to fruition. Further, the CEC has an independent responsibility to conduct a thorough and neutral certification process. And the Commission has been clear that its approval of a power purchase contract should not be used by any parties to influence whether the CEC determines to certify the project and find it CEQA compliant. For these reasons, we find no legal error.

5. Least-Cost Best-Fit

Utilities must employ least-cost best-fit criteria to evaluate procurement bids. The criteria are comprised of both quantitative and qualitative factors.[37] CEJA and

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[36] CEJA and Sierra Club suggest that absent Commission approval, it is highly unlikely the facility would obtain sufficient financing or generate sufficient revenue to merit construction. They offer nothing to substantiate this view, however. Their speculation in that regard is not grounds for error. (See, e.g., *Order Instituting Investigation on the Commission's Own Motion into the Operations and Practices of Pacific Gas and Electric Company Regarding anti-Smart Meter Consumer Groups* [D.14-12-027] (2014) at pp. 2-3 (slip op.).)

[37] See, e.g., *Order Instituting Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning* [D.04-12-048] (2004), at p. 217 [Finding of Fact Number 86] & p. 244 [Ordering Paragraph Number 26(d) (slip op.) (See also SCE-1, at pp. 34-48; SCE-2, Appendix A to Appendix D, Independent Evaluator Report, at pp. 5-9 & Appendix D, Attachment A, at pp. A-1 to A-8.)

Sierra Club argue that approval of the Puente contract was flawed because we relied on prepared written testimony in which SCE maintained the contract was supported by both qualitative and quantitative factors. They assert that in fact: (1) the testimony was uncorroborated out of Court hearsay that cannot be relied upon for the truth of what was asserted; (2) the quantitative evidence showed the contract did not merit approval; and (3) the only thing supporting approval was SCE's qualitative assumption of a resource shortage. (CEJA/Sierra Club Rhg. App., at pp. 15-17, citing *The Utility Reform Network v. Public Utilities Commission* ("*TURN v. PUC*") (2014) 223 Cal.App.4th 945.) These issues are addressed below.

a. SCE's Testimony

CEJA and Sierra Club contend that *TURN v. PUC* establish SCE's testimony could not be relied because it was uncorroborated out of court statement. We agree that *TURN v. PUC* prohibits reliance on uncorroborated testimony where the truth of an out of court statement is disputed. But we do not agree that the testimony in question violated that prohibition.

In this case, SCE's testimony was effectively corroborated. It was subject to cross-examination, and the fact that SCE's bid evaluation relied on both a quantitative and qualitative assessment was verified by the Independent Evaluator.[38]

b. The Quantitative Evidence

CEJA and Sierra Club assert the quantitative assessment did support contract approval because debt equivalence considerations forced SCE to restructure the contract.[39] (CEJA/Sierra Club Rhg. App., at pp. 15-16, citing SCE-1, at p. 48.)

It is true SCE restructured the contract. However, that does not mean the contract was unsupportable. The testimony showed that restructuring was beneficial.[40]

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[38] SCE-2, Attachment D, Independent Evaluation Report, at p. 3, 5-12, 38-39.

[39] Debt equivalence affects a utility's credit rating.

[40] SCE-1C (Confidential), at p. 48. A citation to the record that is labelled confidential does not mean disclosure of any confidential information contained therein.

In addition, debt equivalence is just one quantitative factor. CEJA and Sierra Club do not address any other quantitative factors and establish why on whole, they did not support contract approval.

c. The Qualitative Evidence

CEJA and Sierra Club assert SCE relied solely upon an assumed retirement of the Mandalay and Ellwood peakers, and no evidence supported that conclusion. They also maintain we have never expressed reliability concerns due to the possible retirement of those peakers. We disagree.

The Commission has expressly articulated capacity and reliability concerns in connection with plant retirements. The *Track 1* Decision found a resource shortage would exist in the Moorpark area due to the anticipated retirement of the Mandalay and Ormond Beach OTC units.[41] We also found that procurement was necessary to avoid impacts on transmission voltages and loadings under some operation considerations.[42]

Additionally, like a quantitative analysis, several factors contribute to a complete qualitative analysis. CEJA and Sierra Club do not address any other qualitative considerations and show why they did not merit contract approval. They also ignore evidence presented by SCE and the CAISO regarding reliability issues in the Moorpark area that supported approval of the contract.[43] Thus, they fail to show why contract approval was unreasonable on the whole.

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[41] *Track 1 Decision* [D.13-02-015], *supra,* at pp. 6, 68-73, 124 [Finding of Fact Numbers 38-40] (slip op.).

[42] *Track 1 Decision* [D.13-02-015], *supra,* at p. 72 (slip op.).

[43] See, e.g., SCE-1, at pp. 6-8, 90; RT Vol. 1, SCE/Bryson, at pp. 89 l:21 to 90 l: 16, pp. 112 l:17 to 113 l: 3, pp. 123 l:14 to 124 l:17; RT Vol 2, SCE/Chinn, at pp. 214 l: 17 to 223 l:27; CAISO-1, at pp. 3-4; CAISO-2, at pp. 7-8; CAISO-3, at pp. 2-3.

C. Center for Biological Diversity Application for Rehearing

1. Loading Order

a. Track 1 Decision

Center contends the *Track 1 Decision* failed to require SCE to comply with the preferred resource Loading Order, and failed to mandate that any of the resources for the Moorpark sub-area be of any certain character.[44] Thus, we left compliance to SCE. (Center Rhg. App., at pp. 2-3.) That is incorrect.

The *Track 1 Decision* clearly required compliance with the Loading Order.[45] And while we often do prescribe what resources a utility must obtain, we need not always do so. In some instances it may not be possible or practical to predetermine the specific type of resources that should be procured in a given area. For example, in this case, we recognized that gas-fired (i.e., non-preferred) resources may be reasonable or necessary to meet the area's local reliability needs.[46]

In Center's view we should have found that SCE failed to comply with the Loading Order. However, the Independent Evaluator Report confirms that SCE included preferred resources in its evaluation process, and conducted fairly substantial outreach to solicit all resource types.[47] Despite that, SCE received nowhere near enough cost-effective preferred resource final offers to meet the minimum required capacity need. It accepted all cost-effective offers, but then had to meet remaining need with gas-fired

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[44] See also the Commission's Energy Action Plan located at: http://www.cpuc.ca.gov/PUC/energy/resources/Energy+Action+Plan/. As stated in section 454.5(9)(C), that means that in meeting its energy needs, a utility must:

> first meet its unmet resource needs through all available energy efficiency and demand-side resources *that are cost effective, reliable, and feasible.*

(Pub. Util. Code, § 454.5, subd. (9)(C), emphasis added.)

[45] See, e.g., *Track 1 Decision* [D.13-02-015], *supra*, at pp. 10-11, 78-83, 131-132 [Ordering Paragraph Number 4(g)] (slip op.).

[46] *Track 1 Decision* [D.13-02-015], *supra,* at pp. 123 Finding of Fact Number 26], & p. 124 [Finding of Fact Numbers 38 & 39] (slip op.).

[47] SCE-2, Appendix D, Independent Evaluator Report, at pp. 31-36.

resources.[48] Thus, there was simply no basis to conclude SCE had failed comply with the Loading Order to the extent it was possible.

While we find no error or deficiency, we will modify the Decision as set forth in the below ordering paragraphs to clarify this point.

b. Material Issue

Center contends that Loading Order compliance was a material issue that we failed to address in any fashion. (Center Rhg. App., at p. 3.)

We agree this issue is important in any procurement decision. But in any given proceeding we have discretion to determine what issues are considered material, and many times Loading Order compliance is simply subsumed in the overall evaluation of solicitation results.[49] Here, the issue was indirectly subsumed in the following broad scoping issue:

> 2. Does the Application comply with the procurement authority granted by the Commission in D.13-02-015?[50]

We did in fact render a formal finding and conclusion on this issue, finding that that SCE substantially complied with the procurement directives (which included Loading Order considerations).[51] It is also important to point out that what constitutes Loading Order compliance is not necessarily the same in all cases. It cannot be assumed that *any* preferred resource merits approval simply because it is a preferred resource. As section 454.5(9)(C) makes clear, acceptable preferred resources must also be cost-effective, reliable, and feasible. And preferred resource considerations must be balanced

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[48] As previously noted, SCE was required to obtain between 215-290 MW of capacity in the Moorpark subarea. SCE received only 12 MW of available cost-effective preferred resources. One additional offer was eliminated as not cost-effective. (SCE-2C (Confidential), Appendix D, Independent Evaluator Report, Appendix B, at pp. B-11 to B-26, Table B-6.).

[49] See, e.g., *Pacific Telephone and Telegraph Company v. Public Utilities Commission* (1965) 62 Cal.2d 634, 648, 659-661.

[50] D.16-05-050, at p. 7 [Listing the formal Scope of Issues to be determined.].

[51] D.16-05-050, at p. 35 [Finding of Fact Number 1], & p. 37 [Conclusion of Law Number 1].

with the Commission's paramount obligation to ensure a safe and reliable electrical system, as well as just and reasonable rates.[52] If these things cannot be achieved by the preferred resources bid into a solicitation, they should not be selected despite our goal of utilizing preferred resources over conventional generation.

In this instance we already recognized that in light of the retiring OTC plants, gas-fired or OTC-like generation on those sites might be a reasonable and cost-effective option.[53] And the record evidence showed SCE's ability to utilize Loading Order resources was limited by the actual offers received. Thus, Center fails to establish error.

c. Record evidence

Center contends the Decision ignored evidence it presented regarding 200 MW of potential preferred resources in the Moorpark area. Center argues those resources would have eliminated any need for gas-fired generation (the Puente contract).

We did not ignore Center's testimony, but it did not appear that the resources Center referred to were actually bid into the solicitation and/or even would have qualified for final selection. The record showed there were fewer overall offers in the Moorpark sub-area, and SCE accepted all cost-effective preferred resources that were offered.[54] That was still far short of the identified need. SCE could not select or propose approval of resources that are not bid into the RFO. Nor were we required to discuss resource options that were merely speculative possibilities.

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[52] See, e.g., *Track 1 Decision* [D.13-02-015], *supra,* at pp. 79-80; *Track 4 Decision* [D.14-03-004], *supra,* at pp. 12-15; p. 139 [Conclusion of Law Number 37] (slip op.).

[53] *Track 1 Decision* [D.13-02-015], *supra,* at p. 123 [Finding of Fact Number 26], & p. 124 [Finding of Fact Numbers 38 & 39] (slip op.).

[54] RT Vol. 1, SCE/Bryson, at p. 80 l:5-28, pp. 112 l:17 to 113 l:3; SCE-1, at p. 50. (See also SCE-1C (Confidential), at pp. 26-29, 40.)

2. Environmental Review

Center asserts that whether the Commission was required to conduct CEQA review was material to this proceeding, but we made no findings or conclusions on this issue. (Center Rhg. App., at p. 4.)

This issue was identified in the scope of this proceeding.[55] And we did make a related finding, stating:

> There is no clear or compelling reason based on the record in this proceeding to modify the process of allocating responsibilities between this Commission and the CEC that has been used successfully for many years, by deferring Commission contract review until the CEC environmental review is complete.

(D.16-05-050, at p. 37 [Conclusion of Law Number 5].)

Although we do not find error, we will modify the Decision as set forth in the below ordering paragraphs to clarify our rationale regarding the need for CEQA review.

Center acknowledges the CEC's CEQA role, but argues we should also have conducted environmental review. Center reasons that Commission capacity need determinations, as well as subsequent contract approvals act as a "catalyst for foreseeable future development" that will almost certainly to have a significant effect on the environment. (Center Rhg. App., at pp. 4-11, citing *City of Antioch v. City Council of the City of Pittsburg* ("*City of Antioch*") (1986) 187 Cal.App.3d 1325, 1337-1338.)

We do not find *City of Antioch* to be analogous. There, a negative declaration was prepared for an approved road and sewer construction project. The Court found that a full EIR should have been prepared, because the sole reason the road and sewer were built was to facilitate further development. (*Id.* at p. 1337-1338.)

Commission need determinations do not act in the same way. The sole reason for a need determination is not to facilitate the development of new generation. It

[55] D.16-05-050, at p. 8, Issue 4.

is to identify when and where local energy capacity needs may impact grid reliability. That action is simply consistent with our statutory obligation to ensure reliable electric service.

Further, at the time of a need determination it is entirely unclear how the capacity need will be filled. At best, one could speculate or opine as to possible new generation projects. But argument, speculation, and unsubstantiated opinion are not substantial evidence for purposes of CEQA.[56]

Similarly, approval of a power purchase contract does not trigger CEQA review. As explained above, it merely authorizes a utility to purchase energy from a facility that may, or may not, ultimately be constructed. And the Commission has no discretionary approval to bring such a project to fruition.

Center argues, however, that the CEC limits its analysis of project alternatives if the Commission has already approved a contract for a particular project that has been proposed. (Center Rhg. App., at pp. 11-13.)

Even if that is true, which Center does not prove, that is an issue that should be addressed before the CEC and in any challenge of its CEQA review and certification process. It does not mean this Commission is required to preempt the CEC or circumvent its CEQA conclusions as the lead agency by conducting its own CEQA review.[57]

Finally, Center contends the Decision failed to offer a legally cognizable rationale for declining to conduct CEQA review, because it cited to a case involving a writ denial to find no CEQA was required. Center argues that cursory writ denials (with no Court opinion) cannot be relied because the issue was never fully decided. (Center

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[56] See, e.g., *County Sanitation District No. 2 of Los Angeles County v. County of Kern* (2005) 127 Cal.App.4th 1544, 1580-1581; *Citizens Committee to Save Our Village v. City of Claremont* (1995) 37 Cal.App.4th 1157, 1171-1172.

[57] Center also argues the Puente contract was unreasonable because it contained a penalty clause tied to whether and when the project is approved. (Center Rhg. App., at p. 10.) But it offers no law to establish such a clause is unlawful or triggers CEQA review of the contract.

Rhg. App., at pp. 16-22, citing *Consumers Lobby Against Monopolies v. Public Utilities Commission* ("*CLAM*") (1979) 25 Cal.3d 891, 902-905.)

Center ignores there is a substantial body of Commission precedent finding that CEQA review is not required for power purchase contract approvals. As such, it was not unreasonable or unlawful to rely on the Commission's precedent to deny Center's challenge.

While we find no error, we will modify the Decision as set forth in the below ordering paragraphs to provide clarity on this issue.

3. RFO Bias

Center contends it was error to approve the Puente contract because SCE's RFO process was biased against preferred resources.[58] (Center Rhg. App., at pp. 25-30.) Center's specific allegations are addressed below.

a. Contract Dates

Center contends that the *Track 1 Decision* precluded SCE from taking energy deliveries before 2021, but SCE solicited contracts as early as 2016 and 2018.

Nothing in the *Track 1Decision* prohibited deliveries before 2021. We said only that SCE must fill the identified capacity need *by* 2021. And it noted that need could occur prior to 2021 due to the anticipated closure of certain once-through cooling plants.[59]

Similarly, the *Track 1 Decision* expressed concerns regarding the long lead time needed for some resources to actually be capable of delivering electricity. Thus SCE was encouraged to conduct its solicitation and file its applications as soon as

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[58] Center suggests the Moorpark RFO process was flawed because more preferred resource offers were received for the LA Basin than for Moorpark. (Center Rhg, App., at pp. 23-26.) But this ignores that the exact same RFO process was vetted and used for both the LA Basin and Moorpark. It may be difficult to know with certainty why one area received less offers, but that does not mean there was a flaw in the solicitation.

[59] *Track 1 Decision* [D.13-02-015], *supra,* at pp. 2, 6, 68, 131 [Ordering Paragraph Number 2] (slip op.).

possible (2013-2014). And the Energy Division was authorized to allow some procurement to move forward faster.[60]

Center criticizes SCE's reasons for needing some deliveries sooner.[61] But it offers no facts to refute SCE's rationale. Nor does it show it was unlawful given the authorization and process approved in the *Track 1 Decision.*

b. Time Allowed for Bids

Center asserts that the 91-day window allowed for offers prejudiced preferred resource companies, because they are smaller and have less staffing resources to prepare bids. (Center Rhg. App., at pp. 27-28.) Center fails to establish error.

As noted above, we encouraged a fast solicitation process. And Center offers nothing to show that a 91-day window for offers was unusually short or improper. The record also showed that SCE had lengthened the time for bidders to provide offers in order to increase competition and the ability to receive offers.[62] In addition, the record showed that SCE conducted sufficient outreach to ensure adequate participation by all potential bidders.[63] Thus, there was no evidence that potential bidders were prejudiced in terms or timing or process.

c. Pro Forma Contracts

Center claims that SCE marginalized distributed generation ("DG") vendors because it had pro forma contracts for other resource types, but not for DG bidders. (Center Rhg. App., at pp. 28-29.)

Utilities are not required to provide separate pro forma contracts for every resource type. In this instance, SCE reasonably explained that it first wanted to see if one

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[60] *Track 1 Decision* [D.13-02-015], *supra,* at pp. 4, 90, 92-93, 133 [Ordering Paragraph Number 8] (slip op.).

[61] See, e.g., RT Vol. 1 SCE/Bryson, at pp. 89 l:21 to 90 l:16, 123 l:14 to 124 l: 17; RT Vol. 2 SCE/Chinn pp. 221l:28 to 223 l:23.

[62] SCE-10, at p. 2, Ch. III, pp. 16-33.

[63] SCE-7, at pp. 12-13; RT Vol. 1 SCE/Bryson, at pp. 71 l:10 to 74 l:4, 77 l:28 to 78 l:22.

of the other seven formats could accommodate DG bids. It also said it would work with bidders on acceptable terms if needed.[64]

Center concedes that may have been a reasonable explanation, but argues vendors had no way to know this. We disagree. The solicitation materials did advise potential bidders that some proposals may not fit the pro forma formats, but that SCE would work with bidders to address their needs. Thus, it is not clear how any participant was prejudiced.

d. Security

Center objects to the fact SCE required RFO bidders to post a security. Center argues even SCE acknowledged some bidders may not be used to such a requirement. Thus, the security "surely" prevented bidders with less financial ability from participating. (Center Rhg. App., at p. 29.)

There is nothing unlawful or unusual about requiring bidders to post a security. They are often sought as credit and performance assurances. Here, SCE appeared to have tailored the security requirements based on resource types. Center offers nothing to show that the amounts sought were unreasonable or burdensome.[65] Nor do they show any potential bidders were in fact excluded from bidding due to this requirement. Thus, we find no error.

e. Excluded Resources

Center contends we gave undue deference to CAISO's "worthless opinions," as a result of which SCE was allowed to exclude two-hour demand response products from consideration. (Center Rhg. App., at pp. 29-30.)

It was not unreasonable to defer somewhat to the CAISO's views given its role in managing California's electric grid.[66] Indeed, the *Track 1 Decision* explicitly

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[64] SCE-3, Appendix E: Solicitation Materials, at pp. E-11, E-25, E-137.

[65] SCE-3, Appendix E: Solicitation Materials, at pp. E-153.

[66] Pub. Util. Code, §§ 345 – 352.7; *Track 1 Decision* [D.13-02-015], *supra*, at p. 136 [Ordering Paragraph Number 14] (slip op.).

required SCE to seek the CAISO's input concerning performance characteristics for local reliability.[67]

The Independent Evaluator Report confirmed that the RFO did require four-hour bids, but also allowed an option for two-hour bids. Two-hour bids were ultimately excluded, however, because they did not provide sufficient savings. In addition, our resource adequacy ("RA") rules require a resource be able to provide four hours of capacity over a three consecutive days to qualify as an RA resource, and the CAISO had concerns that two-hour products would not meet system reliability needs.[68] Thus, two-hour products were not wrongly or unlawfully excluded.

4. Need

Center contends it was unreasonable to approve the Puente contract because the Decision failed to demonstrate 215-290 MW are needed in Moorpark. (Center Rhg. App., at pp. 30-36.)

This contention is flawed given our framework for utility procurement. The Commission's process flows from the goals of section 454.5 to ensure safe and reliable electric service as well as reasonable service for customers at just and reasonable rates. Based on these objectives, the Commission has developed a two-step Long Term Procurement Planning ("LTPP") process.

In step one, we render a "needs determination" to identify what new system-wide and or local capacity generation should be obtained.[69] Utilities then solicit

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[67] See, e.g., *Track 1 Decision* [D.13-02-015], *supra,* at p. 136 [Ordering Paragraph Number 14] (slip op.); *Track 4 Decision* [D.14-03-004], *supra,* at p. 146 [Ordering Paragraph Number 11] (slip op.).

[68] SCE-2, Appendix D, Independent Evaluator Report, at p. 20; SCE-1, at pp. 8, 18; RT Vol. 1, SCE/Bryson pp. 107 l:14 to 108 l:25, 109 l:26 to 110 l:15.

[69] See, e.g., *Rulemaking re Long Term Procurement Plans* (2012) [R.12-03-014], at p. 3; *Track 1 Decision* [D.13-02-015], *supra*, at pp. 4-5 (slip op.).

bids to fill the energy need via an RFO or bilateral contract, monitored by an Independent Evaluator to ensure a fair and reasonable process is used.[70]

In step two, generally a separate proceeding, we evaluate a utility's application for approval of procurement contracts that resulted from the RFO. At this juncture, capacity need is no longer an issue. That has already been determined by a decision such as the *Track 1 Decision.*

Center argues, however, that changed circumstances warranted reconsideration of need here. The Commission has recognized that sometimes certain circumstances may change. But, in the interest of a timely and orderly procurement process, we rarely revisit need at this juncture in the procurement process. As explained on D.06-11-048:

> Our long term procurement proceedings are intended to monitor changes in forecasts. In order to permit timely action in response to Commission determinations of need for new generation resources, *it is crucial that we not be sidetracked by second-guessing recent determinations absent evidence of significant errors.*

(*Results of Long Term RFO* [D.06-11-048] (2006) at p. 10 (slip op.) (emphasis added.).)[71]

Even if Center's concerns here were considered, they do not establish error. Center argues the need determination was flawed because the CAISO failed to consider the McGrath Power Plant (a 47.2 MW facility) in its modeling of need for the *Track 1 Decision.* Center argues that while the CAISO's 2011-2012 Transmission Plan referenced the plant, there were not actual models to prove it was included. Thus, need for Moorpark was actually less and the Commission erred in giving weight to the CAISO's analysis. (Center Rhg. App., at p. 32.)

[70] Pub. Util. Code, § 454.5, subd. (f).

[71] See also *Rulemaking re Long-Term Procurement Plans* [R.12-03-014] (2012) at p. 3 (slip op.).

We did not rely solely on the CAISO's analysis to arrive at the need determination. At the same time, it was not unreasonable to give some weight to the CAISO's recommendations given its grid adequacy responsibilities. Further, it is reasonable to conclude that CAISO's reference to the McGrath Power plant in its Transmission Plan indicated that it was indeed considered. At the very least, McGrath was factored into CAISO's 2014-2015 update analysis, and it did not appear to reduce CAISO's need estimate.[72]

Center also contends the *Track I Decision* wrongly assumed closure of the Ormond Beach Generating Station. However, record evidence showed that Ormond Beach will not operate after 2020.[73] Thus, the *Track 1 Decision* did not err.

D. Request for Oral Argument

Center requests that the Commission grant oral argument. (Center Rhg. App., at p. 37.) Such requests are governed by Rule of Practice and Procedure 16.3, which provides:

> (a) If the applicant for rehearing seeks oral argument, it should request it in the application for rehearing and explain how oral argument will materially assist the Commission in resolving the application, and demonstrate that the application raises issues of major significance for the Commission because the challenged order or decision:
>
> (1) adopts new Commission precedent or departs from existing Commission precedent without adequate explanation;
>
> (2) changes or refines existing Commission precedent;
>
> (3) presents legal issues of exceptional controversy, complexity, or public importance; and/or

[72] RT Vol. 2, at p. 235; 26-28. CAISO 2015-2016 Transmission Plan, Appendix D, at p. 5 [Identifying a 234 MW deficit in the Moorpark sub-area in 2025.].

[73] See, e.g., Response of the California Independent System Operator Corporation to Motion to Set Aside the Submission and Reopen the Record to Take Additional Evidence, dated May 13, 2016.

(4) raises questions of first impression that are likely to have significant precedential impact.

(See also Cal. Code of Regs., tit. 20, Rule 16.3.)

We deny Center's request because it neither explained how oral argument will materially assist us in resolving this matter, nor demonstrates how the application raises any issues within the above criteria. Center merely states that it requests the Commission hear oral argument on this motion.

Further, none of the above criteria are even remotely implicated by Decision. Commission decisions approving or denying a utility's proposed procurement contracts are a routine part of the Commission's authority under sections 380, 399.11 *et seq*., and 454.5. There was nothing particularly unique or unusual about this particular Decision or approval of the Puente Project contract. And all the relevant issues were fully litigated and briefed. Therefore, oral argument would provide no material assistance or benefit.

III. CONCLUSION

For the reasons stated above, we modify D.16-05-050 as specified below, and deny the applications for rehearing of D.16-05-050, as modified, because no legal error was shown.

THEREFORE, IT IS ORDERED that:

1. D.16-05-050 is modified as follows:

   a. The first paragraph on page 17 of D.16-05-050 is modified as follows:

      The Commission's direction in D.07-12-052 provides guidance regarding what types of bid evaluation criteria the Commission expects utilities to consider in their solicitation process. However, neither D.07-12-052 nor subsequent procurement decisions have specified the degree to which environmental justice should be weighed or considered by the utilities. For example, D.07-12-052 did not clarify or determine how environmental justice should be weighed against factors such contract economics, other environmental considerations, the Commission's obligation to ensure a reliable electric grid, and the obligation to ensure just and reasonable rates.

For purposes of this procurement application, we find that the Puente contract was consistent with our policy to encourage the use of Brownfield sites. In addition, the solicitation results indicate the contract was reasonable in light of other relevant procurement criteria. Accordingly, selection of the Puente contract is reasonable on the whole.

b. The first full paragraph on page 19 of D.16-05-050 is modified as follows:

In future procurement applications, we should endeavor to more explicitly consider environmental justice issues in our review of proposed procurement contracts. However, in order to more efficiently and effectively do that, utility procurement applications should include sufficient information regarding the consideration of this criteria in the RFO process. The Commission's long-term procurement plan (LTPP) proceeding (a Rulemaking proceeding applicable to the industry as a whole) is an appropriate forum to address the type of information the utilities must provide and give further guidance on this issue. The Commission recently opened Rulemaking (R.) 16-02-007 to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements. The preliminary scope of R.16-02-007 includes potential procurement rule changes. Additional environmental justice rules or guidance should delineate between the role of this Commission in evaluating the reasonableness of a procurement contract, as opposed to the role of the CEC for purposes of its CEQA-equivalent environmental review. And while we recognize that case specific considerations make it difficult to weigh all proposed procurement contracts with complete uniformity, further guidance should be developed concerning the appropriate balance between issues such as: the policy favoring Brownfield sites; environmental justice considerations; other economic considerations, and grid reliability.

c. Finding of Fact Number 3, on page 35 of D.16-05-050 is modified as follows:

   D.07-12-052 included environmental justice as among the criteria utilities were urged to consider in their procurement solicitations.

d. Conclusion of Law Number 3, on page 37 of D.16-05-050 is modified as follows:

   D.07-12-052 requires utilities to consider any disproportionate resource sitings in low income and minority communities in their procurement solicitations. Procurement applications should be clear how a utility considered this issue.

e. Finding of Fact Number 13, on page 36 of D.16-05-050 is modified as follows:

   The evidence showed there were insufficient cost-effective preferred resource bids in the Moorpark sub-area to meet the identified need. Therefore, the Puente Project contract is necessary to meet the identified local reliability need in the Moorpark sub-area. The need determination for the Moorpark sub-area in D.13-02-015 was largely based on the retirement of Mandalay Units 1 and 2 and the Ormond Beach once-through-cooling generation units.

f. Conclusion of Law Number 6, on page 37 of D.06-05-050 is modified to state:

   Because there were insufficient cost-effective preferred resource offers to meet the identified need in the Moorpark sub-area, selection of the Puente Project contract is reasonable and complies with the requirements set out in D.13-02-015.

g. Finding of Fact Number 19, on page 37 of D.16-05-050 is added to state:

   The CEC is the lead agency for environmental review of the Puente Project.

h. Finding of Fact Number 20, on page 37 of D.16-05-050 is added to state:

   Commission precedent consistently shows that power purchase contract approval by this Commission does not trigger environmental review or the need to defer approval pending project approval by the CEC.

2. Southern California Edison's motion for leave to file a confidential response to the applications for rehearing is denied.
3. Rehearing of D.16-05-050, as modified, is denied.
4. This proceeding, Application (A.)14-11-016, remains open.

This order is effective today.

Dated December 1, 2016, at San Francisco, California.

MICHAEL PICKER
President
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
CARLA J. PETERMAN
LIANE M. RANDOLPH
Commissioners

17. Tricia Winterbauer

Michael J. Carroll
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Costa Mesa, California 92626-1925
Tel.: (714) 540-1235
michael.carroll@lw.com

Attorneys for Applicant

State of California

Energy Resources

Conservation and Development Commission

In the Matter of: Application for Certification for the PUENTE POWER PROJECT	Docket No. 15-AFC-01 EXPERT DECLARATION OF TRICIA WINTERBAUER REGARDING ALTERNATIVE SITES – SITE CONTAMINATION ISSUES

I, Tricia Winterbauer, declare as follows:

1. I am employed by AECOM, which has been retained by the Applicant to conduct certain analyses associated with the proposed Puente Power Project (Project) and am duly authorized to make this declaration.

2. I earned a Bachelor of Arts in Environmental Studies from University of California, Santa Barbara in 1992. I have over 20 years of experience regarding the evaluation of transportation, storage, use and disposal of hazardous materials and industrial wastes and the potential environmental impacts thereof. A copy of my current curriculum vitae is attached to this declaration as Attachment A. Based on my education, training and experience, I am qualified to provide expert testimony as to the matters addressed herein.

3. I prepared or participated in preparing, and am knowledgeable of the contents of, the following Applicant's Exhibits:

- Applicant's Exhibit No. 1011: Application for Certification (AFC) Section 4.5, Hazardous Materials (CEC TN #204219-12);

- Applicant's Exhibit No. 1020: AFC Section 4.14, Waste Management (CEC TN #204219-21); and
- Applicant's Exhibit No. 1041: Application for Certification, Appendix M Waste Management (CEC TN #204220-13).

4. I have reviewed and am knowledgeable of the contents of the California Energy Commission (CEC) Staff Final Staff Assessment (FSA), Part 1, Section 4.2, Alternatives (portions pertaining to site contamination at identified alternative sites) (CEC TN #214712).

5. The FSA acknowledges existing soil and groundwater contamination at the Ormond Beach Area Off-Site Alternative (FSA, p. 4.2-92). I conducted further desktop/online evaluation of the Ormond Beach Area Off-Site Alternative regarding the existence of soil and groundwater contamination at the alternative site, and the potential for any existing contamination to result in adverse effects during construction or operation of a power plant at that site.

6. The Ormond Beach Area Off-Site Alternative site was previously the subject of a voluntary clean-up under the oversight of the California Department of Toxic Substances Control (DTSC). January 2002, the DTSC and a former property owner entered into a Voluntary Cleanup Agreement to conduct a Preliminary Endangerment Assessment under the Department's oversight. Contamination at the site resulted from chemical manufacturing operations, and the chemicals of concern are benzene, methyl tertbutyl ether (MTBE) and xylenes. Soils are contaminated with ethylbenzene, chlorinated solvents, and xylenes. Groundwater is impacted by ethylbenzene, chlorinated solvents, styrene, xylene, and benzene. Additional information about prior cleanup at the site can be found at Envirostor Database: http://www.envirostor.dtsc.ca.gov/public/profile_report.asp?global_id=56280098.

7. Following the cleanup, the DTSC imposed a Land Use Covenant on the site to be incorporated by reference in each and every deed and lease for any portion of the site. The Land Use Covenant is attached to this declaration as Attachment B. Soil management activities at the site are subject to the following requirements:

- No activities that will disturb the soil at or below 5 feet below grade shall be allowed at the Property without a Soil Management Plan pre-approved by the DTSC in writing.
- Any soil brought to the surface shall be managed in accordance with all applicable provision of state and federal law.

Similar to development at the Project site, development at the Ormond Beach Area Off-Site Alternative would require development of a Soil and Groundwater Management Plan to be approved by the DTSC prior to any subsurface earthwork on the property. The Soil and Groundwater Management Plan would include a land use history of the property, including description and locations of known contamination, the nature and extent of previous investigations and remediation at the site, and procedures to be followed during earthwork to identify potentially impacted soil and groundwater and dispose of impacted material according to applicable regulations.

8. Based on the information and analysis contained herein, it is my expert opinion that development of a power plant on the Ormond Beach Area Off-Site Alternative site poses potential risks similar to those posed by development of the Project at the proposed site. While development on the alternative site would not involve demolition activities, construction activities at the alternative site would pose risks similar to demolition and construction activities at the proposed Project site, and there is no reasonable basis for distinguishing between the two sites with respect to this issue.

9. Except where stated on information and belief, the facts set forth herein are true of my own personal knowledge, and the opinions set forth are true and correct articulations of my opinions. If called as a witness I could and would testify competently to the facts and opinions set forth herein.

10. I hereby sponsor this declaration into the evidentiary record of these proceedings as Applicant's Exhibit No. 1135.

Executed on January 24, 2017, at Santa Barbara, California.

I declare under penalty of perjury of the laws of the State of California that the foregoing is true and correct.

Tricia Winterbauer

Tricia Winterbauer

ATTACHMENT A

AECOM

Tricia Winterbauer
Senior Environmental Specialist

Education

BA/Environmental Studies/1992/ University of California, Santa Barbara
Certificate of Hazardous Material Management/1994/University of California, Berkeley

Years of Experience

With AECOM: 20 years

Ms. Winterbauer has 20 years of experience in multi-site Phase I and Phase II Environmental Assessments, environmental regulatory compliance and permitting projects, hazardous waste soil and groundwater investigations, energy development projects, and occupational health and safety projects.

Experience

Energy Development Projects

Ms. Winterbauer has conducted permitting of power generating facilities through the California Energy Commission's Application for Certification (AFC) and CEQA permitting processes for new power generation facilities. She has also assisted existing power generation facilities with the development of environmental and health and safety compliance plans and documentation.

Technical Lead, Puente Power Project Application for Certification, NRG Oxnard Energy Center LLC. Managed the data collection and preparation of the Waste Handling section of the Application for Certification (CEQA-equivalent document) for the proposed 262 megawatt natural gas-fired generation facility in Oxnard, California. Responsibilities included identifying and quantifying potential waste streams associated with the construction and operation of the power plant, determining the applicable laws, ordnances, regulations, and standards governing waste generated at the facility, and evaluating the potential impacts and mitigation measures to be implemented during construction and management activities.

Task Leader, Sentinel Energy Project. Hazardous materials, hazardous waste, and worker safety AFC compliance. Developed Construction and Operations Hazardous Materials and Hazardous Waste Management Plans, and the operations Health and Safety Program for the facility for 2013–2014.

Task Leader, Pio Pico Energy Center. Hazardous materials, hazardous waste, and worker safety for the AFC of a 200 MW natural gas-fired power plant located in Otay Mesa. The AFC was submitted in February, 2011.

Task Leader, Agincourt and Marathon Solar Projects CEQA Analysis and Permitting, Mojave Desert. Hazardous materials and public safety for the CUP applications and Mitigated Negative Declarations for two 10-20 MW solar PV facilities in San Bernardino County, California.

Task Leader, Watson Cogeneration Steam and Electric Reliability Project. Hazardous materials, hazardous waste, and worker safety for the AFC of an 85 MW natural gas generating facility in the City of Carson. The AFC was submitted in March 2009.

Task Leader, Starwood Power-Midway Peaking Power Plant. Hazardous materials, hazardous waste, and worker safety AFC compliance. Developed

Construction and Operations Hazardous Materials and Hazardous Waste Management Plans, and the operations Health and Safety Program for the facility in 2009.

Task Leader, Calico Solar Project (Solar One Generating Facility). Hazardous materials, hazardous waste, and worker safety for the AFC of an 850 MW solar power generating facility in San Bernardino County. The AFC was submitted to the CEC in December, 2008.

Task Leader, San Joaquin Solar 1&2 Hybrid Solar Thermal Generating Facility. Hazardous materials, hazardous waste, and worker safety for the AFC of a 106.8 MW solar power generating facility in Fresno County. The AFC was submitted to the CEC in November, 2008.

Task Leader, Hydrogen Energy California Integrated Gasification Combined Cycle (IGCC) Power Generating Facility. Hazardous materials, hazardous waste, and worker safety for the AFC of a 390 MW gasification energy facility in Kern County. The AFC was submitted to the CEC in July 2008.

Task Leader, Imperial Valley Solar (Solar Two Generating Facility). Hazardous materials, hazardous waste, and worker safety for the AFC of a 750 MW solar power generating facility in Imperial County. The AFC was submitted to the CEC in June, 2008

Task Leader, Anaheim Municipal Power Station. Hazardous materials, hazardous waste, and worker safety for the AFC of a 200 MW energy facility in Anaheim, Orange County. The AFC was submitted to the CEC in 2008.

Task Leader, Canyon Power Project. Hazardous materials, hazardous waste, and worker safety for the AFC of a 200 MW peaking plant within the City of Anaheim. The AFC was submitted in December 2007.

Task Leader, Carrizo Solar Power Generating Facility Project. Hazardous materials, hazardous waste, and worker safety for the AFC of a 177 MW solar power generating facility in San Luis Obispo County. The AFC was submitted in October, 2007.

Task Leader, Larkspur 3 Energy Facility Project. Hazardous Materials, hazardous waste, and worker safety for the AFC Amendment for the facility located in San Diego. The AFC Amendment was submitted to the CEC in May, 2007.

Task Leader, Panoche Energy Center. Hazardous materials, hazardous waste, and worker safety for the AFC of a 400 MW energy facility in Fresno County. The AFC was submitted to the CEC in August, 2006.

Task Leader, Bullard Energy Center. Hazardous materials, hazardous waste, and worker safety for the AFC of a 200 MW peaking energy facility within Fresno County. The AFC was submitted to the CEC November, 2006.

Task Leader, Magnolia Power Project. Hazardous materials, hazardous waste, and worker safety for the AFC of a 250 MW energy facility within the City of Burbank. The AFC was filed in and the project was licensed in 2003. Assisted in the management of condition compliance activities from 2003 to 2005. Developed Construction and Operations Hazardous Materials and Hazardous Waste Management Plans, Stormwater Pollution Prevention

Plans, A Health & Safety Program and a Risk Management Plan for the facility.

Agua Mansa Power Project. Assisted in the preparation and processing of an application to develop a 49 MW power facility in Colton, California. Project was constructed in 2003. Assisted in environmental compliance activities from 2003 to 2004. Developed Construction and Operations Hazardous Materials and Hazardous Waste Management Plans, a Spill Prevention Countermeasures and Contingency Plan, the operations Health and Safety Program, and a Risk Management Plan for the facility.

Duke Energy Moapa Power Project. Assisted Duke Energy of North America in environmental permitting and construction compliance activities for a power plant project in Clark County, Nevada from 2000 to 2002. Prepared and submitted compliance documents to various local, state and federal agencies. Prepared a permit matrix to track the completion of each of the permits required prior to construction, during construction, and prior to operations. Also assisted with NEPA compliance and coordination with the Bureau of Land Management for the power plant and project linears.

NEPA/CEQA

Ms. Winterbauer has conducted Environmental Impact Reports (EIR), Environmental Impact Statements (EIS) and Environmental Assessments (EA) through the NEPA/CEQA process.

Task Leader, Vandenberg Air Force Base Final Environmental Assessment, East Housing Area Solar Energy Project. Public Health and Safety section for the EA. The EA was submitted in 2014.

Task Leader, Tajiguas Landfill Resource Recovery Project Risk of Upset, Fire Hazard, and Health and Safety Technical Study. Technical study used as the basis for the Project EIR. 2013–2014.

Task Leader, Hollister Avenue Bridge Replacement Project Initial Study/Mitigated Negative Declaration, City of Goleta and Caltrans. Served as task leader for hazardous materials section and the Caltrans Initial Site Assessment for Draft Mitigated Negative Declaration in 2014.

Task Leader, Ekwill Street and Fowler Road Extensions Project Joint NEPA/CEQA Administrative Draft EIR/EA and CEQA-only EIR, City of Goleta and Caltrans. Hazardous Waste and Utilities section for the EA/EIR in Santa Barbara County. The EIR was submitted in 2011.

Task Leader, Los Carneros Road Overhead Bridge Replacement Project Mitigated Negative Declaration, City of Goleta and Caltrans. Hazardous materials section and the Caltrans Initial Site Assessment for Mitigated Negative Declaration. The MND was submitted in 2011.

Task Leader, NextLight AV Solar Ranch Environmental Impact Report. Environmental Safety and Fire Hazards sections for the EIR in Los Angeles County. The EIR was submitted 2009.

Task Leader, Camp Pendleton Hospital Replacement and Exchange Complex Environmental Assessments. Public Safety section for EAs in San Diego County. The EAs were submitted in 2009.

Task Leader, Port of San Diego, North Harbor Demolition Project Environmental Impact Report. Hazardous Materials and Waste and Utilities sections for the EIR in San Diego County. The EIR was approved in 2009.

Task Leader, (SCE) Tehachapi Renewable Transmission Project (TRTP), Proponent's Environmental Assessment Traversing Kern, Los Angeles, and San Bernardino Counties, and Included Portions of the Angeles National Forest and Mojave Desert, California. Hazardous materials section for Proponent's Environmental Assessment (PEA).

Task Leader, Big West Oil LLC, Clean Fuels Project (CFP) at the Bakersfield Refinery Environmental Impact Report. Served as task leader for the Public Safety Section. The EIR was submitted in 2007.

Task Leader, Newhall Land's Resource Management and Development Plan EIS/EIR, Santa Clarita Valley. Served as task leader for hazardous materials section of the EIS/EIR in Los Angeles County.

Phase I Environmental Site Assessments

Managed large portfolio due diligence projects for the development of solar power plants located throughout California, Nevada, Arizona, New Mexico, and Georgia.

Managed and participated in more than 500 Phase I Site Assessments of industrial and commercial facilities throughout California and the United States. Investigations have focused on the potential for soil and groundwater contamination resulting from past and present site use. Specific tasks have included proposal preparation, budget tracking, site reconnaissance, historical land use investigation, topographic map and aerial photo review, and review of regulatory agency records concerning site compliance issues. Additional tasks have included collection of drinking water samples for analysis of lead content, and visual inspections and characterization of possible asbestos containing materials.

Phase II Environmental Site Assessments

Performed groundwater and soil sampling, at hazardous waste sites throughout California. Responsibilities have included well purging, sample collection, measurement of field parameters, report preparation and recommendations for further sampling analysis.

Environmental Regulatory Compliance – Compliance/Project Management

Prepared regulatory compliance documents for Hazardous Materials, Hazardous Waste, Recycled Water Use and Spill Prevention for Shell Gaviota Marine Terminal Decommissioning Project. 2015-2016.

Prepared regulatory compliance documents for Prysmian Power Link Services Limited for the ExxonMobil Offshore Power System Reliability Project-B during 2013–2014.

Served as task leader for Hazardous Materials, Hazardous Waste, and Worker Safety AFC compliance for the Sentinel Energy Project. Developed Construction and Operations Hazardous Materials and Hazardous Waste

Management Plans for the facility 2013–2014.

Developed Construction and Operations Hazardous Materials and Hazardous Waste Management Plans, and the operations Health and Safety Program for the Starwood Power-Midway Peaking Power Plant facility in 2009.

Assisted in the management of condition compliance activities of the Magnolia Power Plant from 2003–2005. Developed construction and operations Hazardous Materials and Hazardous Waste Management Plans, Stormwater Pollution Prevention Plans, A Health and Safety Program and a Risk Management Plan for the facility.

Conducted environmental compliance activities from 2003–2004 for the Agua Mansa Power Project. Developed Construction and Operations Hazardous Materials and Hazardous Waste Management Plans, a Spill Prevention Countermeasures and Contingency Plan, the operations Health and Safety Program, and a Risk Management Plan for the facility.

Served as task leader for hazardous materials and hazardous waste for a (ECAMP) Audit at Vandenberg Air Force Base in 2003.

Prepared Risk Management Plan for Cal Poly University onsite Refrigeration Unit in 2003.

Conducted biannual regulatory compliance audits for the Stanford Linear Accelerator Facility, Menlo Park, California 1999–2003. The focus of the audits was to conduct documentation review to observe the storage and management of hazardous materials and hazardous waste, wastewater and stormwater.

Developed and updated regulatory compliance documentation and associated permitting including hazardous waste management manuals, hazardous materials management manuals, training programs, hazardous material business plans, biennial reports, risk management plans, storm water pollution prevention plans, and spill prevention control and countermeasure plans for numerous industrial facilities.

Completed numerous Environmental Compliance Audits for industrial, commercial, and medical facilities.

Environmental Regulatory Compliance – Occupational Health and Safety

Prepared health and Safety documents for Prysmian Power Link Services Limited for the ExxonMobil Offshore Power System Reliability Project-B during 2013–2014.

Served as task leader for Worker Safety AFC compliance for the Sentinel Energy Project. Developed the operations Health & Safety Program for the facility, 2013–2014.

Prepared Health and Safety Program for the Chevron Management Company Guadalupe Restoration Project, 2007.

Prepared an Occupational Health and Safety Program to comply with Cal-OSHA requirements for AES Southland 5 California AES power plants in 2004.

Provided weekly occupational health and safety compliance assistance for the Jet Center at Santa Barbara (GE Engine Corporation), 2000–2001. Activities included, weekly health and safety inspections, development of Hazard Communication Program, Injury Illness Prevention Program, Emergency Action/Fire Prevention Plan, Hearing Conservation Program, and an Asbestos Management Program.

Health and Safety Coordinator for the Chevron Richmond Refinery Waste Discharge Order Project from 1997–1999.

Conducted biannual occupational safety and health audits for the Stanford Linear Accelerator Facility, Menlo Park from 1999–2002, California to determine compliance with OSHA standards.

Conducted occupational health and safety audits for the numerous industrial and manufacturing facilities to determine compliance of the OSHA standards.

Developed safety programs for numerous industrial and manufacturing facilities.

ATTACHMENT B

RECORDING REQUESTED BY:

RETIA USA LLC
1201 Louisiana Street, Suite
1800Houston, TX 77002

WHEN RECORDED, MAIL TO:

Department of Toxic Substances Control
9211 Oakdale Avenue
Chatsworth, California 91311
Attention: Sayareh Amirebrahimi
Branch Chief
Brownfields and Environmental
Restoration Program

20150820-00126461-0 1/14
Ventura County Clerk and Recorder
MARK A. LUNN
08/20/2015 04:08:47 PM
975849 $63.00 VA

SPACE ABOVE THIS LINE RESERVED FOR RECORDER'S USE

LAND USE COVENANT AND AGREEMENT

ENVIRONMENTAL RESTRICTIONS

County of Ventura, Assessor Parcel Number(s): 231-0-093-135 and -231-0-093-155
RETIA USA LLC (RETIA) Property
301702

This Land Use Covenant and Agreement ("Covenant") is made by and between RETIA USA LLC (RETIA) (the "Covenantor"), the current owner of property located at 5980 and 6000 Arcturus Avenue, Oxnard in the County of Ventura, State of California (the "Property"), and the Department of Toxic Substances Control (the "Department"). Pursuant to Civil Code section 1471, the Department has determined that this Covenant is reasonably necessary to protect present or future human health or safety or the environment as a result of the presence on the land of hazardous materials as defined in Health and Safety Code section 25260. The Covenantor and the Department hereby agree that, pursuant to Civil Code section 1471 and Health and Safety Code section 25355.5, the use of the Property be restricted as set forth in this Covenant and that the Covenant shall conform with the requirements of California Code of Regulations, title 22, section 67391.1.

ARTICLE I

STATEMENT OF FACTS

1.1. Property Location. The Property that is subject to this Covenant, totaling approximately 14.335 acres, is more particularly described in the attached Exhibit A, "Legal Description", and as depicted in Exhibit B. The Property is located in the area now generally bounded by Arcturus Avenue on the west, McWane Boulevard on the south, and industrial properties on the north and east. The Property is also identified as County of Ventura, Assessor Parcel Number(s) 231-0-093-135 and 231-0-093-155.

1.2. Remediation of Property. This Property has been investigated under the Department's oversight. The Site was used by various operators to manufacture polyester resins since the 1960s. The principal raw materials involved in the manufacturing have included bromine, styrene, maleic anhydride and methylene chloride. These materials were historically stored in above ground tanks and 55-gallon drums. Previous investigation and multimedia sampling at the property indicated that the soil at the property was contaminated with ethylbenzene, chlorinated solvents and xylene. The groundwater beneath the property was also contaminated with ethylbenze, chlorinated solvents, styrene, xylene and benzene. On January 2, 2002, the Department and former property owner, Reichhold Inc., entered into a Voluntary Cleanup Agreement for Reichhold Inc. to conduct a Preliminary Endangerment Assessment under the Department's oversight. According to the Preliminary Endangerment Assessment Report Addendum, dated March 2007, the highest level of VOCs found in groundwater at the property were benzene, toluene and xylene and concentrations of 0.85 ug/L, 0.9 ug/L and 0.24 ug/L respectively which were below their respective Maximum Contaminant Levels of 1ug/L, 150 ug/l and 1,750 ug/L. A Human Health Risk Assessment (HHRA) was conducted to provide a site-specific evaluation of potential risk. The Updated HHRA, dated October 15, 2007, concluded that potential cumulative excess life time cancer risk (ELCR) from all carcinogenic volatile compounds detected in the groundwater and the soil gas at the Property is below the Department regulatory point of departure value for unrestricted land use of 1×10^{-6}. For the future residential exposure of direct contact with soil, the potential cumulative ELCR from all carcinogenic chemicals of potential concern is 1×10^{-5}, which is above the Department regulatory point of departure value for unrestricted land use of 1 x 10^{-6}. As demonstrated in the HHRA, the cumulative risk associated with direct contact exposures for the hypothetical residential scenario is above the unrestricted land use point of point of departure of 1 x 10^{-6}. Therefore, a Land Use Covenant is needed to restrict the use of the Property in order to protect present or future human health or safety or the environment. In accordance with Health and Safety Code, Division 20, Chapter 6.8, the Department issued a No Further Action letter on January 15, 2008, approving the Preliminary Endangerment Assessment Report Addendum dated March 2007 and the Updated Human Health Risk Assessment dated October 2007, and requiring implementation of a Land Use Covenant because of the potential cumulative ELCR from all carcinogenic chemicals of potential concern at the property.

1.3. Basis for Environmental Restrictions.

As a result of the presence of hazardous substances which are also hazardous materials as defined in Health and Safety Code section 25260, at the Property, and based on the conclusions of the Updated Human Health Risk Assessment, the Department has concluded that it is reasonably necessary to restrict the use of the Property in order to protect present or future human health or safety or the environment, and that this Covenant is required as part of the Department-approved remedy for the Property. The Department has also concluded that the Property, as remediated and when used in compliance with the Environmental Restrictions of this Covenant, does not present an unacceptable risk to present and future human health or safety or the environment.

ARTICLE II

DEFINITIONS

2.1. Department. "Department" means the California Department of Toxic Substances Control and includes its successor agencies, if any.

2.2. Environmental Restrictions. "Environmental Restrictions" means all protective provisions, covenants, restrictions, requirements, prohibitions, and terms and conditions as set forth in this Covenant.

2.3. Improvements. "Improvements" includes, but is not limited to buildings, structures, roads, driveways, improved parking areas, wells, pipelines, or other utilities.

2.4. Lease. "Lease" means lease, rental agreement, or any other document that creates a right to use or occupy any portion of the Property.

2.5. Occupant. "Occupant" or "Occupants" means Owner and any person or entity entitled by ownership, leasehold, or other legal relationship to the right to occupy any portion of the Property.

2.6. Owner. "Owner" or "Owners" means the Covenantor, and any successor in interest including any heir and assignee, who at any time holds title to all or any portion of the Property.

ARTICLE III

GENERAL PROVISIONS

3.1. Runs with the Land. This Covenant sets forth Environmental Restrictions that apply to and encumber the Property and every portion thereof no matter how it is improved, held, used, occupied, leased, sold, hypothecated, encumbered, or conveyed. This Covenant: (a) runs with the land pursuant to Civil Code section 1471 and Health and Safety Code section 25355.5; (b) inures to the benefit of and passes with each and every portion of the Property; (c) is for the benefit of, and is enforceable by the Department; and (d) is imposed upon the entire Property unless expressly stated as applicable only to a specific portion thereof.

3.2. Binding upon Owners/Occupants. This Covenant: (a) binds all Owners of the Property, their heirs, successors, and assignees; and (b) the agents, employees, and lessees of the Owners and the Owners' heirs, successors, and assignees. Pursuant to Civil Code section 1471, all successive Owners of the Property are expressly bound hereby for the benefit of the Department; this Covenant, however, is binding on all Owners and Occupants, and their respective successors and assignees, only during their respective periods of ownership or occupancy except that such Owners or Occupants shall continue to be liable for any violations of, or non-compliance with, the Environmental Restrictions of this Covenant or any acts or omissions during their ownership or occupancy.

3.3. Incorporation into Deeds and Leases. This Covenant shall be incorporated by reference in each and every deed and Lease for any portion of the Property.

3.4. Conveyance of Property. The Owner and new Owner shall provide Notice to the Department not later than 30 calendar days after any conveyance or receipt of any ownership interest in the Property (excluding Leases, and mortgages, liens, and other non-possessory encumbrances). The Notice shall include the name and mailing address of the new Owner of the Property and shall reference the site name and site code as listed on page one of this Covenant. The notice shall also include the Assessor's Parcel Number(s) noted on page one. If the new Owner's property has been assigned a different Assessor Parcel Number, each such Assessor Parcel Number that covers the Property must be provided. The Department shall not, by reason of this Covenant, have authority to approve, disapprove, or otherwise affect proposed conveyance, except as otherwise provided by law or by administrative order.

3.5. Costs of Administering the Covenant to Be Paid by Owner. The Department has already incurred and will in the future incur costs associated with this Covenant. Therefore, pursuant to California Code of Regulations, title 22, section 67391.1(h), the Owner agrees to pay the Department's costs in administering, implementing and enforcing this Covenant.

ARTICLE IV

RESTRICTIONS AND REQUIREMENTS

4.1. Prohibited Uses. The Property shall not be used for any of the following purposes without prior written approval by the Department:

(a) A residence, including any mobile home or factory built housing, constructed or installed for use as residential human habitation.

(b) A hospital for humans.

(c) A public or private school for persons under 18 years of age.

(d) A day care center for children.

4.2. Soil Management. Soil management activities at the Property are subject to the following requirements in addition to any other applicable Environmental Restrictions:

(a) No activities that will disturb the soil at or below 5 feet below grade (e.g., excavation, grading, removal, trenching, filling, earth movement, mining, or drilling) shall be allowed at the Property without a Soil Management Plan pre-approved by the Department in writing.

(b) Any soil brought to the surface by grading, excavation, trenching or backfilling shall be managed in accordance with all applicable provisions of state and federal law.

4.3. Prohibited Activities. The following activities shall not be conducted at the Property:

(a) Drilling for any water, oil, or gas without prior written approval by the Department.

(b) Extraction or removal of groundwater for purposes other than site monitoring without a Groundwater Management Plan pre-approved by the Department in writing.

4.4. Access for Department. The Department shall have reasonable right of entry and access to the Property for inspection, investigation, remediation, monitoring, and other activities as deemed necessary by the Department in order to protect human health or safety or the environment.

4.5. Access for Implementing Operation and Maintenance. The entity or person responsible for implementing the operation and maintenance activities, if any, shall have reasonable right of entry and access to the Property for the purpose of implementing such operation and maintenance activities until the Department determines that no further operation and maintenance activity is required.

4.6. Inspection and Reporting Requirements. The Owner shall conduct an annual inspection of the Property verifying compliance with this Covenant and shall submit an annual inspection report to the Department for its approval by June 15th of each year. The annual inspection report must include the dates, times, and names of those who conducted the inspection and reviewed the annual inspection report. It also shall describe how the observations that were the basis for the statements and conclusions in the annual inspection report were performed (e.g., drive by, fly over, walk in, etc.). If any violation is noted, the annual inspection report must detail the steps taken to correct the violation and return to compliance. If the Owner identifies any violations of this Covenant during the annual inspection or at any other time, the Owner must within 10 calendar days of identifying the violation: (a) determine the identity of the party in violation; (b) send a letter advising the party of the violation of the Covenant; and (c) demand that the violation cease immediately. Additionally, a copy of any correspondence related to the violation of this Covenant shall be sent to the Department within 10 calendar days of its original transmission.

4.7 Five-Year Review. In addition to the annual reviews noted above, after a period of five (5) years from June 15, 2015 and every five (5) years thereafter, Owner shall submit a Five-Year Review report documenting its review of the Environmental Restrictions and its evaluation to determine if human health and the environment are being adequately protected by the Environmental Restrictions. The report shall describe the results of all inspections, sampling analyses, tests and other data generated or received by Owner and evaluate the adequacy of the Environmental Restrictions in protecting human health and the environment. As a result of any review work performed, the Department may require Owner to perform additional review work or modify the review work previously performed by Owner.

ARTICLE V

ENFORCEMENT

5.1. Enforcement. Failure of the Owner or Occupant to comply with this Covenant shall be grounds for the Department to require modification or removal of any Improvements constructed or placed upon any portion of the Property in violation of this Covenant. Violation of this Covenant, such as failure to submit (including submission of any false statement) record or report to the Department, shall be grounds for the Department to pursue administrative, civil, or criminal actions, as provided by law.

ARTICLE VI

VARIANCE, REMOVAL AND TERM

6.1. Variance from Environmental Restrictions. Any person may apply to the Department for a written variance from any of the Environmental Restrictions imposed by this Covenant. Such application shall be made in accordance with Health and Safety Code section 25223.

6.2 Removal of Environmental Restrictions. Any person may apply to the Department to remove any of the Environmental Restrictions imposed by this Covenant or terminate the Covenant in its entirety. Such application shall be made in accordance with Health and Safety Code section 25224.

6.3 Term. Unless ended in accordance with paragraph 6.2, by law, or by the Department in the exercise of its discretion, this Covenant shall continue in effect in perpetuity.

ARTICLE VII

MISCELLANEOUS

7.1. No Dedication Intended. Nothing set forth in this Covenant shall be construed to be a gift or dedication, or offer of a gift or dedication, of the Property, or any portion thereof, to the general public or anyone else for any purpose whatsoever.

7.2. Recordation. The Covenantor shall record this Covenant, with all referenced Exhibits, in the County of Ventura within 10 calendar days of the Covenantor's receipt of a fully executed original.

7.3. Notices. Whenever any person gives or serves any Notice ("Notice" as used herein includes any demand or other communication with respect to this Covenant), each such Notice shall be in writing and shall be deemed effective: (a) when delivered, if personally delivered to the person being served or to an officer of a corporate party being served; or (b) five calendar days after deposit in the mail, if mailed by United States mail, postage paid, certified, return receipt requested:

To Owner:

Mr. Doug Loutzenhiser
Vice President
RETIA USA LLC
486 Thomas Jones Way, Suite 110
Exton, PA 19341-2528

And

To Department

Ms. Sayareh Amirebrahimi
Branch Chief, Brownfields and Environmental Restoration Program
Department of Toxic Substances Control
9211 Oakdale Avenue
Chatsworth, California 91311

Any party may change its address or the individual to whose attention a Notice is to be sent by giving advance written Notice in compliance with this paragraph.

7.4. Partial Invalidity. If this Covenant or any of its terms are determined by a court of competent jurisdiction to be invalid for any reason, the surviving portions of this Covenant shall remain in full force and effect as if such portion found invalid had not been included herein.

7.5. Statutory References. All statutory or regulatory references include successor provisions.

7.6. Incorporation of Exhibits. All exhibits and attachments to this Covenant are incorporated herein by reference.

IN WITNESS WHEREOF, the Covenantor and the Department hereby execute this Covenant.

Covenantor: RETIA USA LLC

By: Danny Kite

Title: President

Danny Kite, President

Date: 8/19/15

Department of Toxic Substances Control:

By:

Title: Branch Chief

Sayareh Amirebrahimi, Branch Chief
Brownfields and Environmental Restoration Program – Chatsworth Office

Date: 8/20/2015

A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document.

State of California

County of LOS ANGELES

On AUGUST 20, 2015 before me,

M. BOSE, PUBLIC NOTARY

(space above this line is for name and title of the officer/notary),

personally appeared SAYAREH AMIREBRAHIMI, who proved to me on the basis of satisfactory evidence to be the person(~~s~~) whose name(~~s~~) is/~~are~~ subscribed to the within instrument and acknowledged to me that ~~he~~/she/~~they~~ executed the same in ~~his~~/her/~~their~~ authorized capacity(~~ies~~), and that by ~~his~~/her/~~their~~ signature(~~s~~) on the instrument the person(~~s~~), or the entity upon behalf of which the person(~~s~~) acted, executed the instrument.

I certify under PENALTY OF PERJURY under the laws of the State of California that the foregoing paragraph is true and correct.

WITNESS my hand and official seal,

M. Bose (seal)

Signature of Notary Public

NCC1 M. BOSE
Commission No. 2041082
NOTARY PUBLIC-CALIFORNIA
LOS ANGELES COUNTY
My Comm. Expires SEPTEMBER 12, 2017 NCC1

A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document.

State of Texas

County of Harris

On August 19, 2015 before me, Susan Velasquez, personally appeared Danny Kite, who proved to me on the basis of satisfactory evidence to be the person whose name is subscribed to the within instrument and acknowledged to me that he executed the same in his authorized capacity, and that by his signature on the instrument the entity upon behalf of which the person acted, executed the instrument.

WITNESS my hand and official seal,

Susan Velasquez

Signature of Notary Public

NOTARY PUBLIC STATE OF TEXAS

SUSAN VELASQUEZ
My Commission Expires
September 18, 2016

(Personalized Seal)

EXHIBIT "A"

All that certain real property situated in the County of Ventura, State of California, described as follows:

PARCEL "B", AS SHOWN AND DESIGNATED ON THAT CERTAIN LOT LINE ADJUSTMENT (PLANNING AND ZONING PERMIT NO. 98-5-42), RECORDED MAY 14, 1998 AS INSTRUMENT NO. 98-76147, OF OFFICIAL RECORDS, IN THE CITY OF OXNARD, COUNTY OF VENTURA, STATE OF CALIFORNIA AND BEING ALL OF PARCEL 2, OF LOT MERGER (PLANNING AND ZONING PERMIT NO. 98-5-41) RECORDED MAY 11, 1998 AS INSTRUMENT NO. 98-73258 OF OFFICIAL RECORDS.

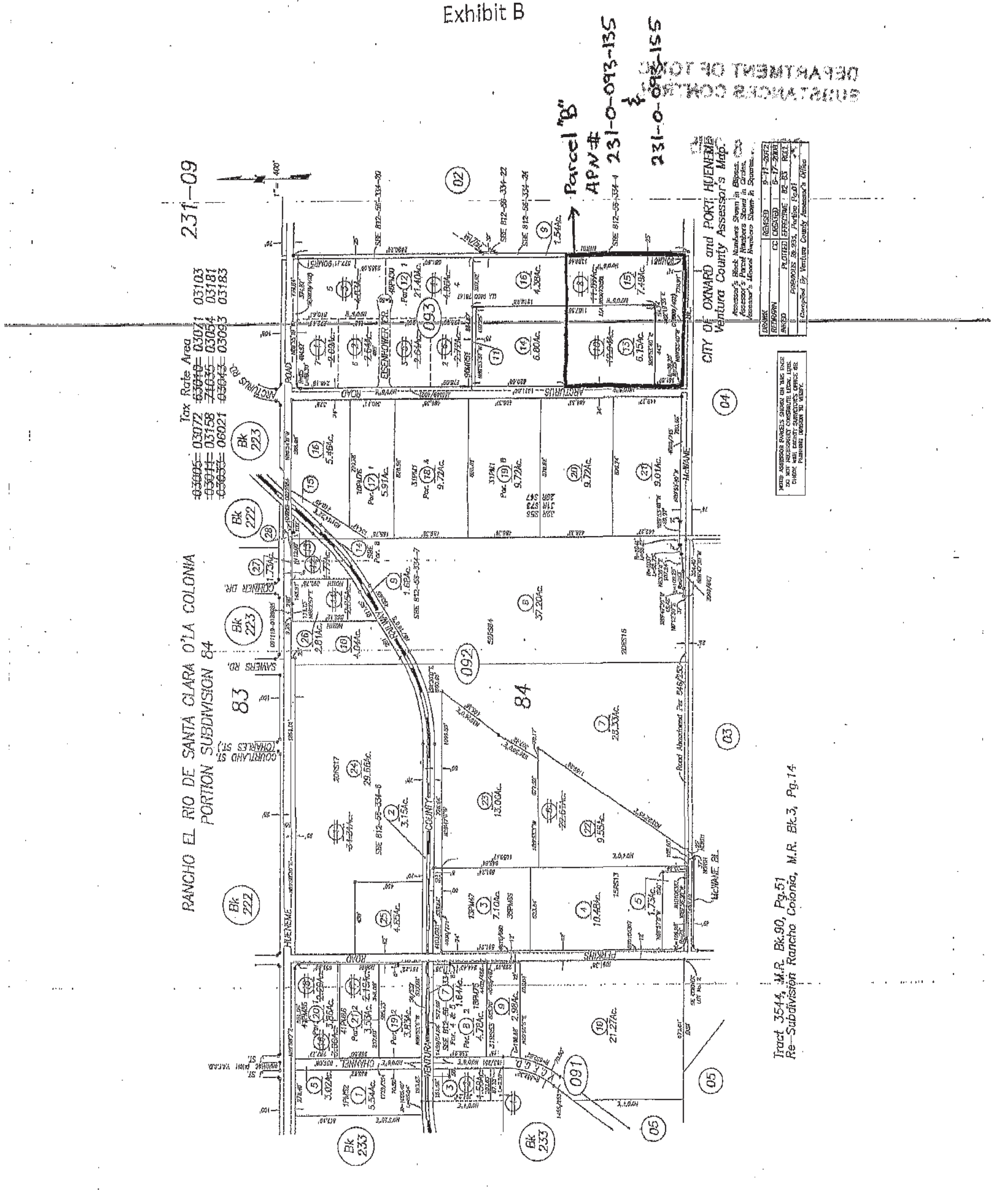
EXCEPT THEREFROM THE NORTHERLY 620.50 FEET OF SAID PARCEL 2.

ALSO EXCEPTING FROM A PORTION, A ONE-HALF OF ALL MINERALS, OIL, GAS AND OTHER HYDROCARBON SUBSTANCES IN AND UNDER SAID LAND, WITHOUT, HOWEVER, ANY RIGHT OF ENTRY IN AND TO THE SUBSURFACE THEREOF AT DEPTH OF LESS THAT 500 FEET BENEATH THE SURFACE FOR THE DEVELOPMENT OR REMOVAL OF SAID SUBSTANCES, AS RESERVED BY CLIFFORD B. JOHNSON AND OTHERS IN THE DEED RECORDED SEPTEMBER 22, 1961 IN BOOK 2050, PAGE 386 OF OFFICIAL RECORDS.

ALSO EXCEPTING FROM A PORTION, A ONE-FOURTH OF ALL OIL, GAS, MINERALS AND OTHER HYDROCARBON SUBSTANCES IN AND UNDER SAID LAND, WITHOUT, HOWEVER, ANY RIGHT TO SURFACE ENTRY IN AND TO THE SUBSURFACE THEREOF AT A DEPTH OF LESS THAN 500 FEET BENEATH THE SURFACE FOR DEVELOPMENT OR REMOVAL OF SAID SUBSTANCES, AS RESERVED BY T. G. M. INVESTMENT CO., INC., AS TITLE HOLDING COMPANY FOR OXNARD DEVELOPMENT CO., A JOINT VENTURE UNDER TITLE HOLDING AGREEMENT DATED FEBRUARY 13, 1960 AND RECORDED MARCH 11, 1960 IN BOOK 1842, PAGE 243 OF OFFICIAL RECORDS, IN THE DEED RECORDED DECEMBER 7, 1961, IN BOOK 2081, PAGE 67, OF OFFICIAL RECORDS.

Assessor's Parcel Number: 231-0-093-135 and 231-0-093-155

Exhibit B


Parcel "B"
APN # 231-0-093-135
&
231-0-093-155
DEPARTMENT OF TOXIC SUBSTANCES CONTROL
231-09
Tax Rate Area
CITY OF OXNARD and PORT HUENEME
Ventura County Assessor's Map.
RANCHO EL RIO DE SANTA CLARA O'LA COLONIA
PORTION SUBDIVISION 84
Tract 3544, M.R. Bk.90, Pg.51
Re-Subdivision Rancho Colonia, M.R. Bk.3, Pg.14
ARCTURUS ROAD
EISENHOWER DR.
HUENEME ROAD
PERKINS ROAD
McWANE BL
VENTURA COUNTY RAILWAY
CHANNEL
093
092
091