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SOUTHERN CALIFORNIA EDISON®

An *EDISON INTERNATIONAL®* Company

(U 338-E)

# *TESTIMONY OF SOUTHERN CALIFORNIA EDISON COMPANY ON THE RESULTS OF ITS 2013 LOCAL CAPACITY REQUIREMENTS REQUEST FOR OFFERS (LCR RFO) FOR THE WESTERN LOS ANGELES BASIN*

**PUBLIC VERSION**

Before the

**Public Utilities Commission of the State of California**

Rosemead, California
November 21, 2014

# SCE-1: Testimony of Southern California Edison Company on the Results of its 2013 Local Capacity Requirements Request for Offers (LCR RFO) for the Western Los Angeles Basin

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# I.

## INTRODUCTION

In 2013 and 2014, in two separate tracks of the 2012 Long Term Procurement Plan ("LTPP") proceeding (Tracks 1 and 4), the California Public Utilities Commission ("Commission" or "CPUC") authorized Southern California Edison ("SCE") to procure 1,900 to 2,500 Megawatts ("MW") of electrical capacity in the Western Los Angeles sub-area of the Los Angeles basin ("Western LA Basin") local reliability area to meet long-term local capacity requirements by 2021.[1] To meet this need, SCE issued a request for offers ("RFO") seeking new Local Capacity Requirement ("LCR") resources, including Preferred Resources[2] (*i.e.*, Energy Efficiency ("EE"), Demand Response ("DR"), renewable resources, Combined Heat and Power ("CHP") resources, and Distributed Generation ("DG")), Energy Storage ("ES") resources, and Gas-Fired Generation ("GFG").

SCE has extensive experience running solicitations for the procurement of various power-related products. The LCR RFO, however, presented a number of unique and new challenges, including: (1) determining EE and DR incrementality; (2) in front of the meter ("IFOM") ES interconnection; (3) ES charging/discharging tariff rules; (4) ES performance measurement for behind the meter ("BTM") resources; (5) Preferred Resource performance characteristics; (6) locational effectiveness factors

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[1] Decision ("D.") 13-02-015 ("Track 1 decision") at 130-131 (Ordering Paragraph ("OP") 1); D.14-03-004 ("Track 4 decision") at 141-143 (OP 1). D.13-02-015 also authorized SCE to 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. D.13-02-015 at 131 (OP 2). The Commission required SCE to file a separate Application for approval of contracts for the Moorpark sub-area. *Id*. at 135 (OP 11). See A.14-11-XXX for the Moorpark Application and testimony.

[2] Preferred Resources are defined in the State's Energy Action Plan II, at page 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 [energy] efficiency and demand response, we rely on renewable sources of power and distributed generation, such as combined heat and power applications. To the extent [energy] 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."

("LEFs"); and (7) debt equivalents issues.[3] Notwithstanding these challenges, SCE was able to successfully execute approximately 500 MW of Preferred Resource and ES contracts through its LCR RFO. SCE will continue to seek to acquire Preferred Resources and ES in the Western LA Basin to meet the minimum 600 MW procurement authorization the Commission provided for Preferred Resources and ES in the LTPP Track 1 and 4 decisions, as well as address the Commission's assumption that SCE will develop more than 1,000 MW of uncommitted Preferred Resources in the Western LA Basin by 2020.[4]

The LTPP Track 1 and 4 decisions ordered SCE to file an application for approval of all contracts entered into as a result of SCE's LCR RFO for new capacity in the Western LA Basin.[5] In this application ("Application"), SCE explains how it procured the required new LCR resources authorized by the LTPP Track 1 and Track 4 decisions for the Western LA Basin. Chapter II of the Application provides background on the LCR RFO. Chapter III describes the Western LA Basin local reliability area. Chapter IV summarizes the solicitation process, with details on (1) the schedule and structure of the solicitation, (2) bidder requirements, (3) outreach efforts, (4) procurement challenges, (5) SCE's attempts to procure EE and DR incremental to existing programs, (6) SCE's consultation with the California Independent System Operator ("CAISO"), (7) the role of the Independent Evaluator ("IE") and consultation with the Cost Allocation Mechanism ("CAM") group,[6] and (8) the impact of debt equivalence on the LCR RFO. Chapter V provides an overview of bidder participation in the solicitation. Chapter VI explains the valuation and selection process. Chapter VII includes a summary of the solicitation results. Chapter VIII provides SCE's proposal for the allocation of benefits and costs.

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[3] See Section IV.E for further discussion of these issues.

[4] D.13-02-015 at 67, 123-124 (Findings of Fact "FOF" (FOF 31)).

[5] D.13-02-015 at 135 (OP 11). Appendix F explains how this Application meets the requirements of each OP in the Track 1 and Track 4 decisions.

[6] As required by the Commission, SCE conducts procurement reviews with one of two groups, its Procurement Review Group or its CAM group, when appropriate. D.04-12-048 at 241 (OP 15); D.07-12-052 at 127-130, 301 (OP 8). The Procurement Review Group is consulted for procurement on behalf of bundled load while the CAM Group is consulted for procurement on behalf of all benefitting customers.

Chapter IX explains SCE's proposal for recovering the costs of the LCR resources, ratemaking treatment and revenue allocation. Finally, Chapter X addresses additional procurement of Preferred Resources and ES in the Western LA Basin.

This Application seeks approval of 63 contracts selected through the LCR RFO process. A summary of the selected offers is provided in Table I-1 below.

***Table I-1***
***Summary of Selected Offers***

| Product Category | Counterparty | Total Contracts | Max Quantity (LCR MW) |
|---|---|---|---|
| **Preferred Resources and ES** | | | |
| EE | • Onsite Energy Corporation<br>• Sterling Analytics LLC<br>• NRG Energy Efficiency-L LLC<br>• NRG Energy Efficiency-P LLC | 26 | 124.04 |
| DR | • NRG Distributed Generation PR LLC<br>• NRG Curtailment Solutions LLC | 7 | 75.00 |
| Renewable DG | • Solar Star California XXXV, LLC<br>• Solar Star California XXXVI, LLC<br>• Solar Star California XXXVII, LLC<br>• Solar Star California XXXVIII, LLC | 4 | 37.92 |
| ES | • AES ES Alamitos, LLC<br>• Ice Bear SPV #1, LLC<br>• Hybrid-Electric Building Technologies Irvine 1, LLC<br>• Hybrid-Electric Building Technologies Irvine 2, LLC<br>• Hybrid-Electric Building Technologies West Los Angeles 1, LLC<br>• Hybrid-Electric Building Technologies West Los Angeles 2, LLC<br>• Stem Energy Southern California, LLC | 23 | 263.64 |
| | **Total Preferred Resources and ES** | **60** | **500.60** |
| **GFG** | | | |
| GFG | • AES Alamitos Energy, LLC<br>• AES Huntington Beach Energy, LLC<br>• Stanton Energy Reliability Center, LLC | 3 | 1,382.00 |
| | **Total Preferred Resources, ES, and GFG** | **63** | **1,882.60** |

In conjunction with the remaining LCR procurement authorization from the LTPP Track 1 and 4 decisions and the Commission's assumptions on the development of uncommitted Preferred Resources by 2020, it is anticipated that more than half of the Western LA Basin local area reliability needs will be met by Preferred Resources and ES. Table I-2 below summarizes SCE's proposed LCR procurement from this Application and planned LCR resources.

***Table I-2***
***LCR Portfolio Breakdown***

| Resource Bucket | LCR RFO Procurement Recommendation (MW) | Minimum Authorization Remaining (MW) | Uncommitted Resource Assumptions (MW)(1) | Total (MW) |
|---|---|---|---|---|
| **Preferred Resources and Energy Storage** | 501 | 99 | 1339 | 1939 |
| **Gas-Fired Generation** | 1382 | 0 | 0 | 1382 |
| **Total** | **1883** | **99** | **1339(2)** | **3321** |

(1) Track 1 LTPP Decision assumed 800 MW of uncommitted EE and CHP, 200 MW of uncommitted DR, and 339 MW of uncommitted DG in West LA Basin

(2) This total volume does not include additional MWs of Preferred Resources and ES that may be implemented through other procurement activities or programs such as Energy Storage OIR, RPS Solicitations, Preferred Resource Pilot Program, etc.

## II.

## LCR RFO BACKGROUND

On February 13, 2013, the Commission issued D.13-02-015, the LTPP Track 1 decision. The Track 1 decision ordered SCE to procure between 1,400 and 1,800 MW of electrical capacity in the Western LA Basin to meet long-term local capacity requirements by 2021, largely due to the expected retirement of once-through-cooling ("OTC") generation facilities.[7]

The Track 1 decision also ordered SCE to file an LCR procurement plan ("LCR Procurement Plan") explaining how it would conduct its LCR RFO.[8] SCE filed its LCR Procurement Plan on July 15, 2013. In accordance with the Track 1 decision, Energy Division reviewed SCE's LCR Procurement Plan and requested that SCE submit a modified LCR Procurement Plan with additional information. SCE filed its final modified LCR Procurement Plan on August 30, 2013. Energy Division approved SCE's modified LCR Procurement Plan on September 4, 2013. SCE launched its LCR RFO on September 12, 2013.

On March 13, 2014, the Commission issued D.14-03-004, the LTPP Track 4 decision, authorizing SCE to procure an additional 500 to 700 MW by 2021 to meet local capacity needs stemming from the retirement of the San Onofre Nuclear Generating Station ("SONGS").[9] Combined, the LTPP Track 1 and 4 decisions authorize SCE to procure between 1,900 to 2,500 MW in the Western LA Basin.

The LTPP Track 1 and Track 4 decisions require SCE to procure minimum amounts of Preferred Resources, ES[10] and GFG in the Western LA Basin local reliability area as shown in Figure II-1 below.[11] Specifically, SCE's minimum procurement authorization is 550 MW of Preferred Resources,

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[7] D.13-02-015 at 130-131 (OP 1).

[8] *Id*. at 133-134 (OP 5-7).

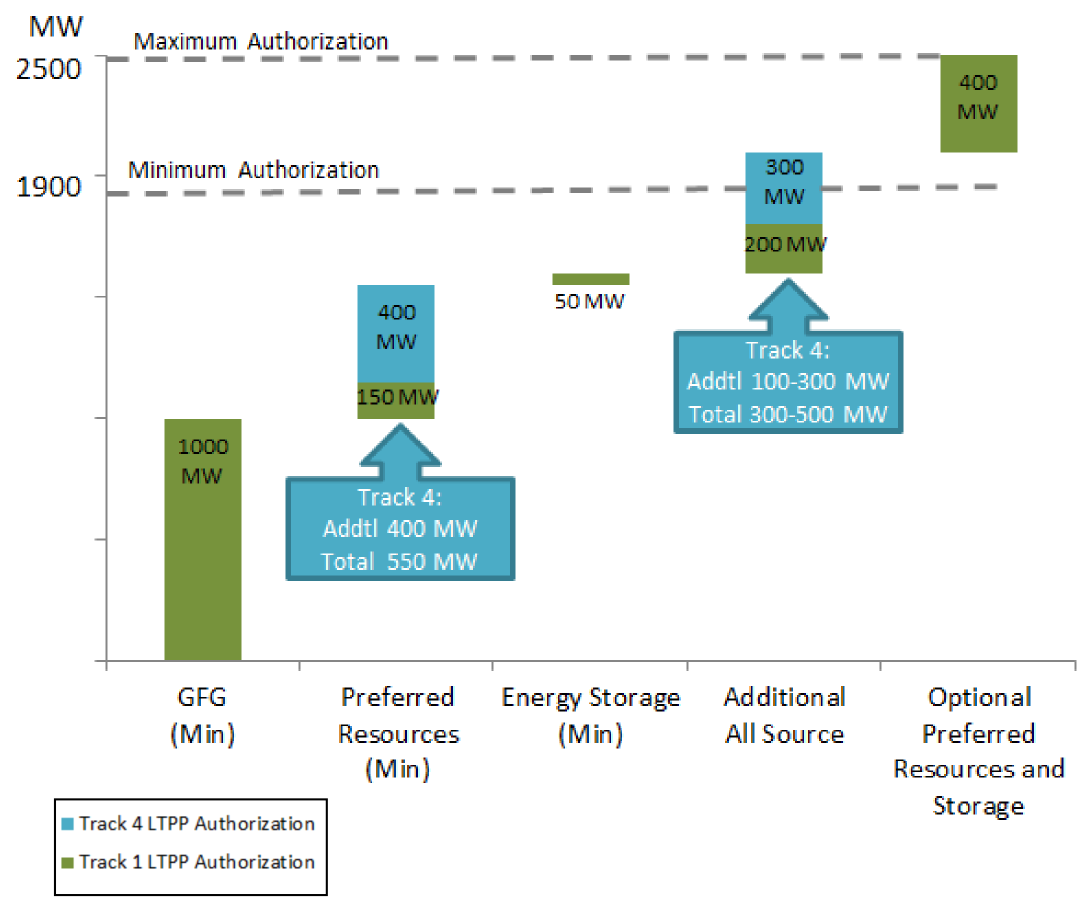
[9] D.14-03-004 at 141-143 (OP 1).

[10] SCE "may also procure energy storage as part of [its] preferred resources requirement[] or all source authorization[] . . . ." D.14-03-004 at 100.

[11] D.13-02-015 at 130-131 (OP 1); D.14-03-004 at 141-143 (OP 1).

50 MW of ES, 1,000 MW of GFG, and an additional 300 MW from any resource type.[12] SCE's maximum procurement authorization includes an additional 400 MW of Preferred Resources and ES, plus an additional 200 MW from any resource type.

***Figure II-1***
***Types of Resources***
***Western LA Basin Procurement Authorization***




[12] D.14-03-004 at 141-143 (OP 1).

## III.

## DESCRIPTION OF THE WESTERN LA BASIN LOCAL RELIABILITY AREA

In its LCR RFO, SCE sought new resources in the Western LA Basin local reliability area, and only accepted offers from resources connected to substation systems in this area. The Western LA Basin is divided into three sub-areas that include 28 A-bank substations[13]: (1) the Northwest LA Basin sub-area, which includes the Eagle Rock, Gould, Goodrich, El Segundo, Chevmain, El Nido, La Cienega, La Fresa, Redondo, Hinson, Long Beach, Lighthipe and Laguna Bell substations; (2) the Western Central LA Basin sub-area, which includes the Center, Del Amo, Mesa, Rio Hondo, Walnut and Olinda substations; and (3) the Southwest LA Basin sub-area, which includes the Alamitos, Barre, Lewis, Villa Park, Ellis, Huntington Beach, Johanna, Santiago and Viejo substations.[14] See Figure III-2 below for a map of the Western LA Basin sub-areas and the A-Bank substations in each sub-area. As stated above, the need for additional capacity in the Western LA Basin is largely due to the expected retirement of approximately 5,900 MW[15] from current OTC generators in the LA Basin due to compliance with State Water Resources Control Board ("SWRCB") policy,[16] and the permanent closure of SONGS.[17]

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[13] An A-Bank substation is a substation which connects the transmission system to the sub-transmission system. These stations typically step voltage down to 66 kV or 115 kV.

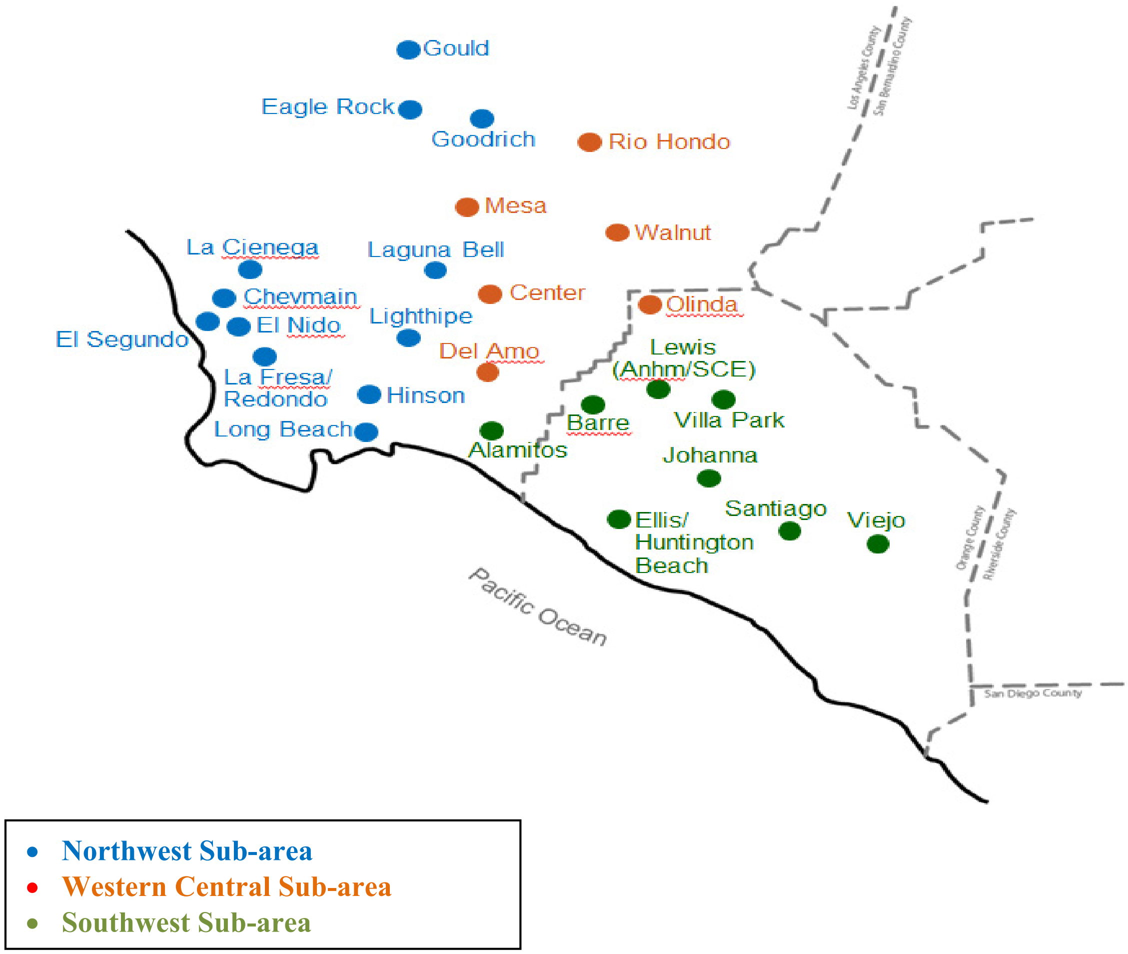
[14] CAISO, *Clarification to the ISO Board-Approved 2013-2014 Transmission Plan: Locational Effectiveness Factor Calculations in the LA Basin Area*, April 23, 2014, at 2. Arcogen and Harborgen were omitted from the list of substations in the Northwest LA Basin sub-area because they are not load serving substations.

[15] D. 14-03-004 at 6.

[16] *See* SWRCB Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (October 1, 2010).

[17] D.13-02-015 at 2.

***Figure III-2***
***Western LA Basin A-Bank Substations***



# IV.

## LCR RFO SOLICITATION PROCESS OVERVIEW

This Chapter describes the following aspects of the solicitation process: (1) the schedule and structure of the solicitation, (2) bidder requirements, (3) outreach efforts, (4) procurement challenges, (5) SCE's attempts to procure EE and DR incremental to existing programs, (6) SCE's consultation with the CAISO, (7) the role of the IE and SCE's consultation with the CAM group and Energy Division, and (8) the impact of debt equivalence.

### A. Solicitation Schedule

In its LCR Procurement Plan, SCE proposed the RFO schedule shown below in Table IV-3.

***Table IV-3***
***SCE's Proposed LCR RFO Schedule***

| No of Days | LCR RFO Step |
|---|---|
| T | Energy Division approves LCR Procurement Plan |
| T+14 | Launch LCR RFO |
| T+103 | Indicative offers submitted |
| T+148 | Shortlisting, contract negotiations commence |
| T+260 | Negotiation deadline |
| T+267 | Final offers submitted |
| T+295 | SCE notifies successful bidders and contract execution |
| T+355 | SCE files application for approval |

On May 2, 2014, Energy Division approved SCE's request to extend the LCR RFO to: (1) resolve issues related to ES; (2) address how to determine whether an EE resource is incremental; (3) conduct additional analysis as a result of CAISO's LEF changes published on April 9, 2014; and (4) follow-up with counterparties with Preferred Resources on outstanding issues in order to complete negotiations. The additional time resulted in enhanced participation and competition amongst Preferred Resource offers. Table IV-4 shows the approved, modified LCR RFO schedule.

***Table IV-4***
***Revised LCR RFO Schedule***

| No of Days | Milestone |
|---|---|
| T | Energy Division approves LCR Procurement Plan |
| T+14 | Launch LCR RFO |
| T+103 | Indicative offers submitted |
| T+148 | Shortlisting, contract negotiations commence |
| T+293 | Negotiation deadline |
| T+300 | Final offers submitted |
| T+328 | SCE notifies successful bidders and contract execution |
| T+359 | SCE files application for approval |

On July 21, 2014, SCE requested a second and final extension to file its Western LA Basin LCR RFO Application on November 21, 2014. The proposed change to the filing date enabled SCE to internally resolve debt equivalency issues that arose with respect to certain products through the incorporation of additional language in the contracts at issue. Those contract changes were then communicated to the impacted bidders. The details of the debt equivalency issues impacting certain contracts is described in Section IV.I. Table IV-5 below shows the final Western LA Basin LCR RFO schedule, which was approved by the Energy Division on July 28, 2014.

***Table IV-5***
***Final Revised LCR RFO Schedule***

| No of Days | Milestone |
|---|---|
| T | Energy Division approves LCR Procurement Plan |
| T+14 | Launch LCR RFO |
| T+103 | Indicative offers Submitted |
| T+148 | Shortlisting, contract negotiations commence |
| T+359 | Negotiation deadline |
| T+365 | Final offers submitted |
| T+415 | SCE notifies successful bidders and contract execution |
| T+443 | SCE files LA Basin Application for approval |

## B. <u>Solicitation Structure</u>

The format of the RFO structure, detailed in SCE's LCR Procurement Plan, was approved by the Energy Division and included an initial solicitation of indicative offers, negotiations on contract terms with "shortlisted" offers, a final price refresh of "shortlisted" offers, and an evaluation and selection process.

Below is a list of steps, in chronological order, that were used in the LCR RFO process:

### 1. Internal Preparation

Prior to launch, SCE finalized all documents that were a part of the LCR RFO (*e.g.*, pro forma contracts, participants' instructions and submittal templates) and reviewed the LCR RFO details with internal and external stakeholders. External stakeholders included the IE, the CAM Group, and Commission staff.[18] The roles of each of the external stakeholders are described in Section IV.H.

### 2. RFO Launch

SCE created an LCR RFO website (hosted on http://www.sce.com) which included all of the information that bidders needed to participate in the process. SCE notified market participants directly, via an extensive email list maintained by SCE, and through various service lists, including those for dockets involving EE, DR and DG matters. SCE also issued a press release which was run in industry publications and sent a notice to various industry organizations. For additional information on outreach efforts see Section IV.D.

After the launch, SCE hosted a bidder's conference to walk through the various aspects of the solicitation, discuss its valuation approach, and respond to questions and concerns. Due to the complexity of the LCR RFO process and the variety of resources solicited, SCE provided a very thorough and detailed overview of the solicitation process, the documents involved, and the valuation process during the bidder's conference. At the request of market participants, SCE also hosted separate EE and ES webinars to provide further details on the contracts, bidding templates, and valuation methodology specific to these resources. All materials from the bidders' conference and webinars were made available on the LCR RFO website. SCE also maintained a list of frequently asked questions ("FAQs") on its LCR RFO website. SCE's LCR RFO materials are included as Appendix E.

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[18] Throughout the LCR RFO process, SCE employed the use of an IE to ensure that all bidders received comparable and non-discriminatory treatment, and periodically consulted with the CAM Group and the Commission's Energy Division.

### 3. Notice of Intent Submission

After reviewing the LCR RFO materials, bidders submitted an official nonbinding notification of which resources they intended to bid. Obtaining this information early in the LCR RFO process helped SCE fine-tune a plan to manage the forecasted workload and address issues related to offer templates associated with new products that were not initially contemplated.

### 4. Indicative Offers Submitted by Bidders

Using the offer templates from the LCR RFO website, bidders submitted non-binding indicative offers. The indicative offers provided pricing that SCE used for shortlist notification. An ancillary benefit of this process is that bidders could input their information directly into submittal templates which allowed SCE to identify anomalies that required additional information. Although it is common for SCE to work with bidders to cure deficiencies on indicative offers, SCE expended significantly more effort working with bidders in the LCR RFO to get a completed and conforming set of offers to value for its shortlist process. Indeed, SCE ultimately ended up working with bidders to cure over eighty percent of the indicative offers received. This was due in large part to ES being a new product, SCE proposing to contract for certain demand-side management ("DSM") products in a new manner, and many of the bidders not having participated in an SCE RFO.

### 5. Shortlist Notification

Based on shortlist criteria and valuation results from indicative offers, SCE notified bidders of whether they had been shortlisted.

### 6. Contract Negotiation

Once the shortlist was determined, SCE and bidders began negotiating the terms and conditions of contract forms based on SCE's published pro forma contracts.

### 7. Commercial Lockdown

At commercial lockdown, all "commercial" terms were finalized (*e.g.*, contract quantity, term, location, operational attributes and restrictions), except for price. These commercial terms describe a potential offer, and need to be finalized sufficiently early to provide adequate time for proper valuation.

### 8. Negotiation Deadline

This deadline was the date by which all terms and conditions of contract forms had to be finalized and ready for execution. Agreement on a negotiated contract form was required for bidders to submit final pricing.

### 9. Final Binding Offers Submission

Bidders submitted final binding prices based on previously negotiated contract forms. These documents represented each bidder's final offer.

### 10. SCE Accepts or Rejects

SCE chose to either outright accept or reject offers. After offer acceptance, SCE and the bidder prepared the final executable form of the contract. As a result of debt equivalency concerns discussed in Section IV.I., the contracts for ES and combined-cycle GFG offers were structured to include an "Embedded Put Option" which included providing the seller with annual energy put option prices to be incorporated into the contract for each year of the contract. In addition, the GFG contracts for CT's were restructured as fixed-price RA contracts and the BTM ES contracts were structured to include a provision that allows the seller to add, remove or replace the assets associated with the contracts as needed.

## C. Requirements and Considerations

For a project to be considered in the LCR RFO, it was required to meet the following general qualifications: minimum capacity quantities for each type of technology; all bidders had to either reduce load or otherwise interconnect in the Western LA Basin at the A-Bank substations (or lower voltage substations connected to the Western LA Basin A-Bank substations) in Figure III-2 above;[19] generation projects had to apply, or have applied, for interconnection to the CAISO grid selecting Full Capacity

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[19] After the CAISO provided its *Clarification to the ISO Board-Approved 2013-2014 Transmission Plan: Locational Effectiveness Factor Calculations in the LA Basin Area*, SCE concluded that it was in customers' economic interest to focus GFG procurement in only the most effective locations, and thus removed GFG offers from the shortlist if the projects were not in the Southwest sub-area of the Western LA Basin. See Section IV.G.2 for discussion of LEFs.

Deliverability Status, qualifying the project to be counted for RA; the project must be incremental (*i.e.*, new capacity); and the delivery had to include the entire calendar year 2021.

SCE considered offers for contract terms of any length as required by the Track 1 decision. However, SCE requested a contract term of up to 20 years as part of its "preferred" contract terms at the launch of the LCR RFO. SCE allowed for flexibility with online dates to accommodate staggered delivery period commencements. Online dates could be as early as 2016 for those projects interconnected to the Johanna and Santiago substations,[20] and 2018 for all other substations. All projects had to be online by January 2021.

Given the desire to facilitate competition within the relatively short solicitation timeline, SCE did not have a minimum transmission study requirement for offers in the LCR RFO. Instead, SCE proposed a cap on transmission network upgrades in its Pro Forma documents with the dollar amount for each contract to be determined through the negotiations.

### D. Outreach Efforts

Historically, SCE has been very successful in its outreach efforts and ensuring potential sellers are aware of a solicitation for renewable, CHP, and conventional resources. However, many of the resources being procured in SCE's LCR RFO process, specifically EE, DR, DG and ES, are not typically procured through SCE's standard power procurement efforts. For that reason, SCE sent emails announcing the launch of the solicitation to CPUC distribution lists for proceedings that involve EE, DR and DG matters. SCE also sent notices regarding the LCR RFO to the following organizations: National Association of Energy Service Companies; California Energy Efficiency Industry Council; Association of Energy Services Professionals; Peak Load Management Alliance; Solar Energy Industries Association; California Solar Energy Industries Association; Solar Electric Power Association; California Energy Storage Association; American Wind Energy Association; and the Fuel Cell & Hydrogen Energy Association. Finally, SCE posted an announcement of the launch of the LCR

[20] SCE allowed for 2016 project start dates for resources connected to Johanna and Santiago substations to offset immediate needs at those locations and to support SCE's Preferred Resources Pilot.

RFO on the Proposal Evaluation & Proposal Management Application website, which has historically been used to notify the market of California's Investor-Owned Utilities' ("IOU") EE solicitations. SCE's additional outreach efforts raised awareness of the LCR RFO, and as a result, the number of potential sellers of Preferred Resources and ES increased. As described below, SCE also emphasized the procurement of Preferred Resources and ES in its bidder's conference.

CPUC General Order 156 ("GO 156") contains "rules governing the development of programs to increase participation of women, minority and disabled veteran business enterprises ("WMDVBEs") in procurement of contracts from utilities as required by Public Utilities Code Sections 8281-8286."[21] In recognition of GO 156, SCE continues to look for opportunities to build an increased pool of diverse suppliers, including WMDVBE participants in power procurement activities. SCE encouraged WMDVBEs to participate in the LCR RFO by including information specific to WMDVBEs in its LCR RFO bidder's instructions and in the LCR RFO bidder's conference presentation. In addition, SCE provided direct one-on-one support to help answer RFO process questions and educate potential WMDVBE bidders on the LCR RFO solicitation documents and process, SCE's supplier diversity development program,[22] and the interconnection study process.

## E. Addressing Procurement Challenges

The LCR RFO presented unique and new challenges to SCE's procurement process. This was the first time SCE administered a solicitation that explicitly sought a range of resource technologies, from demand–side management resources to natural gas-fired generation facilities. Additionally, within the solicitation, it was the first time SCE ever procured ES resources through a competitive solicitation. Overlaying the focus of meeting local reliability needs, these new circumstances led to the following procurement challenges:

[21] CPUC GO 156 at 1.

[22] Information on SCE's supplier diversity development program can be found on the SCE website at www.sce.com/SD.

1. **<u>Energy Efficiency & Demand Response Incrementality</u>**

- See Section IV.F for a discussion of this issue.

2. **<u>In Front of the Meter Energy Storage Interconnection</u>**

- <u>Issue</u>: Current tariffs do not clearly address how ES resources will be interconnected. This uncertainty created confusion around: (1) the appropriate rules for studying the charging of ES, (2) costs associated with necessary upgrades for the charging of ES, and (3) metering requirements for ES.
- <u>Status</u>: SCE is exploring options for establishing interconnection policy for ES consistent with the language in SCE's Rule 21 Tariff, SCE's Wholesale Distribution Access Tariff, SCE's Transmission Owner Tariff, and the CAISO Tariff.

3. **<u>In Front of the Meter Energy Storage Charging/Discharging Tariff</u>**

- <u>Issue</u>: The current tariffs do not contemplate many of the unique characteristics of ES; thus, there is little guidance as to how grid-connected ES devices should pay for the energy they use to charge. In particular, the tariffs are not clear on whether grid-connected storage will pay transmission and distribution access charges. Such uncertainty on relatively large potential charges makes valuation and contracting difficult.
- <u>Status</u>: For IFOM ES devices (*i.e.*, for those devices not located behind a retail customer's meter), SCE plans to separately meter and bill the interconnecting ES customer for its station and auxiliary load (*e.g.*, air conditioning load, heating load, pumping load, and other energy consumed at the project not taken directly into the actual ES device). As a result, the ES station and auxiliary load will be charged at SCE's retail rates. The energy stored by the ES device (which excludes the station and auxiliary load) will be charged the CAISO Locational Marginal Price (*i.e.*, wholesale rates). The CAISO's Tariff is unclear on whether the energy used directly by ES resources will be assessed a Transmission Access Charge ("TAC") in addition to the Locational Marginal Price, as currently occurs with wholesale load customers and pumped hydro storage. If

the CAISO assesses a TAC, it may prompt SCE to create a FERC-jurisdictional distribution access charge for the use of utilities' distribution systems in order to maintain consistent treatment of ES connecting to the transmission and distribution systems. SCE has asked the CAISO to provide an interpretation of its tariff to reduce the outstanding uncertainty on whether access charges apply to grid-connected storage charging.

4. **Energy Storage Performance Measurement for Behind the Meter Resources**

- Background: SCE originally assumed BTM storage performance would be measured by existing demand response performance measurement protocols, which are based on load dropped.
- Issue: Certain bidders[redacted] wanted their performance to be based on metered output of the energy storage device.
- Solution: [redacted][24]

5. **Preferred Resource Performance Characteristics**

- Background: The LTPP Track 1 and 4 decisions require that resources provide the required LCR performance characteristics to be eligible to count as local RA capacity.
- Issue: Performance characteristics were not defined in the LTPP Track 1 and 4 decisions.
- Solution: SCE worked with the CAISO to identify minimum performance characteristics of Preferred Resources in meeting the identified LCR need. As part of this collaboration,

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[23] [redacted]

[24] The 10/10 baseline refers to the current utility demand response programs where performance is measured based on the metered load drop relative to the average consumption over the last 10 similar days.

SCE provided CAISO with a range of portfolios of Preferred Resources with various operational characteristics for LCR effectiveness testing. This allowed the CAISO to conduct analysis to identify the minimum operational characteristics of Preferred Resources in meeting the identified LCR need. As a result, SCE set the maximum response time for DR resources to twenty minutes. In addition, the CAISO's study showed that a maximum of 150 MW of two-hour dispatch/discharge duration for DR and ES resources in the Western LA Basin could be used to meet or reduce LCR need. The CAISO, however, did not study the effectiveness of two-hour resources in meeting system RA requirements beyond the local area and was not prepared to support system RA value for such resources. As a result, SCE decided not to include two-hour resources in its LCR procurement.

### 6. Locational Effectiveness Factors

- Background: The Track 1 decision ordered that LCR "resources must meet the identified reliability constraint identified by the [CAISO]," the "consideration of costs and benefits must be adjusted by their relative effectiveness factor at meeting the [CAISO] identified constraint," and SCE has to use "the most up-to-date effectiveness ratings."[25]
- Issue: SCE launched the RFO using the CAISO studies that were available at the time, with the understanding that new studies were likely to be performed during the RFO process. CAISO's updated studies identified different system constraints as a result of the permanent closure of SONGS and CAISO's new approved transmission projects.[26] This resulted in the Western LA Basin being divided into three sub-areas: Northwest, Western Central, and Southwest. CAISO studied three different scenarios that resulted in three different sets of LEFs for each of the sub-areas.[27]

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[25] D.13-02-015 at 131-132 (OP 4.a, c, and 1).

[26] *See* CAISO, *Clarification to the ISO Board-Approved 2013-2014 Transmission Plan: Locational Effectiveness Factor Calculations in the LA Basin Area*, April 23, 2014, 1-5.

[27] *Id*.

- Solution: All of the LEF scenarios and CAISO's original study showed that resources in the Southwest sub-area of the Western LA Basin (*i.e.*, the Orange County area) are significantly more effective at meeting the LCR need compared to resources located in other sub-areas of the Western LA Basin. Further, SCE concluded that it was likely any large procurement of resources outside of the Southwest sub-area of the Western LA Basin would significantly increase the likelihood that additional LCR procurement would be required beyond the existing Track 1 and 4 authorizations. Therefore, SCE only entertained offers from, and negotiated contracts with, natural gas-fired resources located in the identified preferred location (*i.e.*, the Southwest sub-area of the Western LA Basin). For Preferred Resources, except for IFOM ES, SCE assumed the highest effectiveness of such resources for the entire Western LA Basin. This followed the CAISO's modeling assumption, which included Preferred Resources throughout the entire LA Basin. For IFOM ES, which operates similar to controllable generating units in meeting LCR needs, SCE relied on the LEFs from CAISO's recent studies.[28]

#### 7. Debt Equivalents

- See Section IV.I for a discussion of this issue.

### F. Energy Efficiency and Demand Response Incremental To Existing Programs

#### 1. SCE's LCR RFO Attempts to Procure Preferred Resources Incremental to the Assumptions Used in CAISO's Studies

The Track 1 decision ordered that any RFOs issued by SCE must be for resources that are "demonstrably incremental" to the assumptions used in the studies[29] presented by the CAISO in Track 1 of the LTPP, "to ensure that a given resource is not double counted."[30] The analysis in the CAISO

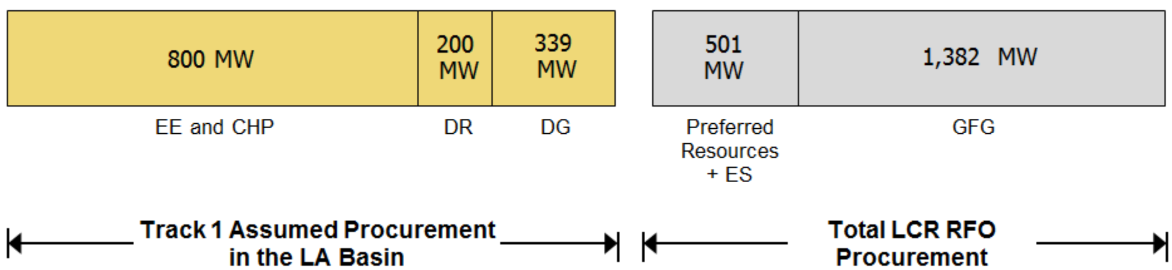
[28] *See id*.

[29] As described in D.13-02-015 at 21, CAISO performed a sensitivity analysis at the request of the CPUC, CEC, and California Air Resources Board to study a variation on the Environmentally Constrained Portfolio.

[30] D.13-02-015 at 131-132 (OP 4.b).

studies and Track 1 decision assumed that 1,339 MW of Preferred Resources would be in place in 2022, as shown in Figure IV-3 below:[31]

***Figure IV-3***
***Committed and Uncommitted Preferred Resources in Western LA Basin***




Although the Track 1 decision assumed that this level of Preferred Resources would be in place, it did not identify the specific Preferred Resources that would be developed. Consequently, there is no way to definitively assess if a resource in SCE's LCR RFO is truly incremental "to the assumptions used in the CAISO studies."[32] To ensure "that a given resource is not double counted," but that all needed resources are ultimately procured, SCE's total Preferred Resource procurement to meet LCR needs must equal the sum of: (1) the Preferred Resource assumptions adopted in the Track 1 decision, and (2) the minimum procurement authorization for Preferred Resources in the LTPP Track 1 and Track 4 decisions. Thus, the totality of SCE's procurement of Preferred Resources to meet LCR needs is the critical procurement objective, and not individual assumptions. Nonetheless, SCE did screen out certain LCR RFO offers as not being incremental through its Tranche analysis identified above and described further below.

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[31] The Track 1 decision adjusted the identified LCR need by assuming 800 MW of uncommitted EE and CHP in the Western LA Basin. D.13-02-015 at 65. An assumed nominal level of 200 MW of DR and 339 MW of distributed generation are also identified in the Track 1 decision. *Id.* at 56, 58.

[32] D.13-02-015 at 131-132 (OP 4.b).

### 2. SCE Assessed Incrementality of Preferred Resources Based on the Characteristics of Individual Offers

Because it would not be practical to delay the procurement of Preferred Resources through SCE's LCR RFO until after the results of SCE's utility-run DSM programs concluded for 2020 deliveries and Track 1 decision assumptions on uncommitted DG and CHP targets were met, SCE commenced with the procurement of Preferred Resources in its LCR RFO recognizing that its total procurement of Preferred Resources through utility programs and its LCR RFO must meet the sum of the assumptions and procurement authorization for Preferred Resources adopted in the LTPP Track 1 and 4 decisions to ensure local area reliability. Additionally, delaying the procurement of Preferred Resources would not have allowed for head-to-head competition of all resource types due to the need to immediately proceed with the LCR solicitation to contract for necessary GFG given its long development cycle.

To move forward with the procurement of Preferred Resources, SCE developed a methodology to categorize Preferred Resource offers based on their likelihood of being incremental to the types of Preferred Resources assumed in the CAISO's studies presented in Track 1 of the LTPP proceeding. This methodology examined the characteristics of each offer, and placed them into one of four "tranches" based on their dissimilarity to SCE's existing DSM programs, and therefore their likely incrementality to the Preferred Resources in CAISO's analysis. EE and DR offers were both assessed using similar, but not identical (due to differences in technology, market characteristics, savings load profiles, etc.), tranche definitions, as shown for EE in Figure IV-4 and for DR Figure IV-5 below:

***Figure IV-4***
***Energy Efficiency Tranche Framework***

| | Category | Description | Incremental | Procure? |
|---|---|---|---|---|
| Tranche 1 | **New Product** (Technical Innovation) | • New measures, programs, strategies, or transactions. Measures outside SCE's DSM portfolio. | Yes | Yes |
| Tranche 2 | **New Use of Existing Products** (Market Innovation) | • Existing measures, but with new customer type, markets, incentive levels, or delivery channel<br>• Hybrid/combination offers (EE, DR, DG, ES) | Yes | Yes |
| Tranche 3 | **Value** | • Existing measures or programs that are *less expensive than current EE program offerings.* | Yes | Yes |
| Tranche 4 | **Do Not Procure: Low Value and/or ineligible savings** | • Existing measures/programs that do not offer the value of Tranche 3 or start in 2015<br>• Savings that are likely ineligible (below code, naturally occurring, ISP, etc) | No | No |

***Figure IV-5***
***Demand Response Tranche Framework***

| | Category | Description | Incremental | Procure? |
|---|---|---|---|---|
| Tranche 1 | **Technical Innovation** | • New measures/technologies that expand the market by enabling new DR solutions or solutions that allow customers to participate who otherwise would not (i.e. dispatchable storage) | Yes | Yes |
| Tranche 2 | **Product / Market Innovation** | • New programs, measures, strategies or transactions (i.e. flexible dispatch)<br>• New resource capabilities (i.e. faster dispatch time) | Yes | Yes |
| Tranche 3 | **Value** | • Existing DR programs but *cheaper than existing* DR Programs | Yes | Yes |
| Tranche 4 | **Do Not Procure: Low Value** | • Existing proposals that do not offer the value of Tranche 3 | No | No |

SCE identifies that the Track 4 decision requires SCE to procure Preferred Resources "in addition to Preferred Resources already required by the Commission to be procured or obtained through decisions in other relevant proceedings,"[33] as well as the additional Preferred Resources ordered in the Track 1 decision. For both EE and DR, Tranches 1 through 3 represent innovation or savings

[33] D.14-30-004 at 141-142 (OP 1.e).

incremental to SCE's existing DSM programs, and SCE recommends that they be considered incremental for purposes of complying with the LTPP Track 1 and 4 decisions.[34]

## G. Consultation With CAISO

### 1. Overview

As mentioned above, in the Track 1 decision the Commission ordered that any resource procured should, among other things, "meet the identified reliability constraint identified by the CAISO" and that SCE "use [] the most up-to-date effectiveness ratings."[35] Information about the studied reliability constraint and resulting effectiveness ratings is contained in the CAISO document, "Clarification to the ISO Board-Approved 2013-2014 Transmission Plan: Locational Effectiveness Factor Calculations in the LA Basin Area." It states:

> The ISO is providing in this document additional information about locational effectiveness factors for the LA Basin area, to assist the resource procurement process of Southern California Edison currently underway. This information is being provided to assist SCE with the direction received from the CPUC in D.13-02-015 to take into account the locational effectiveness of resources as determined by the ISO.[36]

The CAISO analysis in this document is the basis for SCE's use of LEFs in its valuation of offers. Following the CAISO's initial LEF determination in Track 1, the retirement of SONGS and the transmission projects approved in the CAISO's 2013-14 Transmission Plan prompted a need to provide updated LEFs as further described below.

### 2. Locational Effectiveness Factors

Locational effectiveness factors are a measurement of the effectiveness of a resource, located in a particular place/substation, in relieving specific reliability constraint. LEFs are affected by the configuration of the transmission system and the distribution of loads and generating facilities within the area. Higher LEFs point to a resource location being more effective at relieving the subject constraint.

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[34] As discussed in detail in Sections VI.C.3 and VII.B.1, SCE selected one contract that was in Tranche 4.

[35] D.13-02-015 at 131-132 (OP 4.a., l).

[36] CAISO, *Clarification to the ISO Board-Approved 2013-2014 Transmission Plan: Locational Effectiveness Factor Calculations in the LA Basin Area*, April 23, 2014, at 1.

For purposes of this RFO, the CAISO identifies the reliability constraint as a post-transient voltage instability concern based on the most critical contingency that affects the LA Basin and San Diego local capacity areas: the overlapping contingency of the loss of the East County – Miguel 500 kV line, system readjusted, followed by the loss of the Ocotillo – Suncrest 500 kV line.[37] This contingency, which represents a situation in which two 500 kV transmission lines that feed San Diego Gas & Electric's ("SDG&E") territory are lost, is known in shorthand as an "N-1-1" contingency. This contingency will reroute power to the remaining lines that feed SDG&E. The rerouted power flows through lines in the Western LA Basin and produces thermal overloads and voltage deviation violations. Adding generation at key substations will mitigate these violations by reducing power flows pre-contingency and providing voltage support on specific portions of the transmission system to prepare for the contingency.[38] The CAISO determined LEFs based on this N-1-1 contingency.

The CAISO provided LEFs for the three sub-areas that it apportioned in the Western LA Basin: Northwest, Western Central, and Southwest. LEFs for these three sub-areas of the Western LA Basin are provided in three scenarios labeled by the CAISO as A, B and C. The CAISO assumed different levels of transmission and generation development to provide a range of scenarios. Scenario C assumes the successful and timely completion of three transmission projects (*i.e.*, Imperial Valley Flow Controller, Mesa Loop-in and San Luis Rey synchronous condensers), as well as the timely completion of 800 MW of resource additions in San Diego per the LTPP Track 1 and 4 decisions. Scenario A does not assume completion of the transmission projects, and models only 500-550 MW of resource additions coming online in San Diego from the Track 4 LTPP authorization, rather than the full 800 MW[39]. Scenario B is similar to Scenario C, except for the absence of the Imperial Valley Flow Controller project. Table IV-6 below provides the LEFs for the LA Basin sub-areas of each scenario.[40]

[37] *Id*. at 2-3.

[38] SCE Opening Testimony, 2012 LTPP Track IV, p.24, lines 11-17.

[39] D.14-03-004 at 143 (OP 2).

[40] CAISO, *Clarification to the ISO Board-Approved 2013-2014 Transmission Plan: Locational Effectiveness Factor Calculations in the LA Basin Area*, April 23, 2014, at 2.

***Table IV-6***
***Updated Locational Effectiveness Factors***

| Los Angeles Basin Area | Scenario | | |
|---|---|---|---|
| | A | B | C |
| Northwest | 0% | < 13.6% | 56.9% |
| Western Central | not studied | 34.4% | 66.6% |
| Southwest | 50% | 71.7% | 100% |

The LEF values provide a basis for comparing the effectiveness of resources sited in these areas. When comparing the LEFs for Scenario C, the Western Central area has an effectiveness two-thirds that of the Southwest sub-area. This means that for every MW of resources placed in the Southwest sub-area, to achieve the same effect, approximately 1.5 MW must be placed in the Western Central sub-area. The scenarios are shown in sequence in the table starting with the conservative case, Scenario A, followed by Scenario B, the moderate case, and Scenario C, the optimistic case where all transmission and generation projects are modeled. All three scenarios showed the highest locational effectiveness for resources in the Southwest sub-area, indicating that for a range of possible outcomes of generation and transmission projects, resources in the Southwest sub-area are significantly more effective at relieving the identified constraint.

SCE focused on the moderate case, Scenario B, to determine if its 2012 LTPP authorization to meet the CAISO-identified reliability constraint is sufficient. The CAISO's Scenario B reflects that 14,200 MW in the Northwest sub-area and 200 MW and 158 megavars ("MVAr")[41] in the Southwest sub-area are required to resolve the critical N-1-1 contingency for Scenario B.[42] This is well beyond the maximum 2012 LTPP authorization of 2,500 MW for SCE.

The CAISO did not provide the minimum MW required to resolve the critical N-1-1 contingency if all resources were in either the Western Central or Southwest sub-areas, but this minimum value can

[41] Megavars are the portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage.

[42] CAISO, *Clarification to the ISO Board-Approved 2013-2014 Transmission Plan: Locational Effectiveness Factor Calculations in the LA Basin Area*, April 23, 2014, at 4.

be approximated using Scenario B LEFs. Ignoring the resources added to the Southwest sub-area for Scenario B, the Southwest sub-area minimum can be approximated by multiplying the ratio of the LEFs of the Northwest and Southwest sub-areas with the total resources required in the Northwest sub-area to resolve the critical N-1-1 contingency [(13.6 / 71.7 ) x 14,200 MW = 2,693 MW]. The minimum resources required in the Western Central sub-area can be calculated in a similar manner. Table IV-7 below provides the estimated minimum MW required if all resources were in the Northwest, Western Central or Southwest sub-areas.

***Table IV-7***
***Minimum Resources Required to Mitigate Reliability Constraint***

| Scenario B | | |
|---|---|---|
| Los Angeles Basin Area | LEF | Minimum MW Required |
| Northwest | 13.6 | 14,200 |
| Western Central | 34.4 | 5,614 |
| Southwest | 71.7 | 2,693 |

Thus, based on the calculations using Scenario B LEFs, the most effective area to site resources is the Southwest sub-area of the Western LA Basin (requiring 2,693 MW); substantially less than the amount required in the Northwest or Western Central sub-areas. Even for the most effective area, the resources required exceed the total 2012 LTPP maximum procurement authorization of 2,500 MW for SCE. Due to the lower effectiveness of resources in other areas, each MW procured outside of the Southwest sub-area will increase the likelihood of a residual need for future resources and transmission, thus significantly increasing costs to customers and adding resources that would not have otherwise been needed if more effective locations were originally considered in SCE's LCR RFO. Because sufficient GFG offers in the Southwest sub-area were available to meet the procurement authorizations in the Track 1 and 4 decisions, SCE elected not to consider GFG offers for its Northwest and Western Central sub-areas within the Western LA Basin. This approach provided a large block of resources located in the most effective area under a variety of scenarios to relieve the critical N-1-1 reliability constraint.

In order to procure the most effective IFOM ES, SCE utilized Scenario B LEFs in the evaluation of this resource type which showed non-zero LEFs for all three areas. This provides a 72 percent LEF for the Southwest sub-area, exemplifying the importance of this area, but this also allows IFOM ES located in other areas to participate and increase the total amount of ES procured.

Other Preferred Resource offers (*e.g.*, DSM) can be distributed across areas within the Western LA Basin and due to their small size and geographic diversity, are not amenable to the application of LEFs. As such, SCE elected to consider all Preferred Resources, excluding IFOM ES, as equally effective throughout the Western LA Basin. This assumption was also consistent with the CAISO's modeling assumptions.

a) <u>Preferred Resource Characteristics</u>

Preferred Resources will play an important role in meeting the LCR need; however, they do present certain challenges. One of the challenges in the LCR RFO was to identify the minimum operational characteristics of each Preferred Resource type (*e.g.*, response time, dispatch/discharge duration, resource availability, etc.) to meet the LCR need. In order to identify the minimum operational characteristics, SCE initiated a study measuring the LCR effectiveness of Preferred Resources in collaboration with the CAISO. In September 2013, SCE developed, and submitted to the CAISO, several hypothetical portfolios of various Preferred Resource scenarios. The CAISO studied a subset of the submitted portfolios.[43] Results of these studies provided some high-level guidelines and direction on the minimum operational characteristics that were necessary for each Preferred Resource type to meet the LCR need, and SCE refined the required minimum resource attributes accordingly. For example, SCE reduced the maximum response time requirement of DR resources to twenty minutes because of the CAISO's studies and direction. The CAISO studies also indicated there should be a MW quantity cap for two-hour ES and DR resources to meet or reduce the LCR need.

In March 2014, SCE developed and submitted additional hypothetical LCR portfolios to the CAISO. These additional portfolios were more refined because they were based on resource characteristics of the indicative offers submitted to SCE in the LCR RFO. The CAISO study results

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[43] See CAISO's *2013-2014 Transmission Plan* (March 25, 2014) for details on the studies and analysis discussed in Section IV.G.2.a.

indicated that some Preferred Resources are effective in meeting the LCR need in conjunction with GFG and transmission solutions. The results of these studies also suggested that up to 150 MW of two-hour dispatch/discharge resources will be effective in meeting or reducing the identified LCR need in the LA Basin. The CAISO, however, did not study the effectiveness of two-hour resources in meeting the system RA requirements beyond the local area, and was not prepared to support any system RA value for such resources. As a result, SCE ultimately excluded the consideration of two-hour resources from its recommended LCR procurement.

## H. Role of IE and CAM Group

Pursuant to applicable Commission decisions, SCE engaged an IE and consulted with its CAM Group throughout the LCR RFO process.

### 1. Engagement of IE

D.08-11-008 requires an IE for all competitive solicitations that involve affiliate transactions, utility-owned or utility-turnkey offers, and for all solicitations that seek products two years or greater in duration, regardless of who participates.[44] In addition, D.06-07-029 states that an IE is required if an IOU runs a solicitation that seeks to allocate new generation costs in accordance with the CAM outlined in the same decision.[45]

In compliance with these requirements, SCE recommended Sedway Consulting, Inc. ("Sedway") as the IE for SCE's LCR RFO. Sedway is currently in SCE's pre-qualified IE pool and has prior experience developing and running solicitations in other parts of the country for EE, DR, and DG, as well as renewable and conventional resources. Sedway also has some prior experience overseeing the negotiation and evaluation of ES. SCE provided Sedway with a whitepaper and presentation on ES technologies and requested that Sedway review appropriate staff and consultant reports developed pursuant to R.10-12-007, the Energy Storage Rulemaking, to ensure Sedway had the latest information on ES. SCE sought and obtained Energy Division approval to use Sedway as the IE for the LCR RFO.

[44] D.08-11-008 at 39-40 (OP 2).

[45] D.06-07-029 at 28.

Sedway was engaged to ensure that the solicitation process was fair to all qualified bidders and that no SCE affiliate had an undue advantage over non-affiliates in the solicitation.[46] Sedway was required to make a determination as to whether SCE's final selection was fair and free from anti-competitive behavior. Sedway also reported its findings throughout the RFO process to the Energy Division and SCE's CAM Group by participating in meetings that SCE scheduled with both groups. Sedway also communicated with the Energy Division directly regarding the EE/DR incrementality issue. Finally, Sedway completed the CPUC's IE Report Template, with updates pending based on completion of the solicitation. The IE Report has been provided to the Energy Division and a copy is included as Appendix D.

### 2. Consultations with CAM Group and Energy Division

D.06-07-029 adopted a CAM that allows the benefits and costs of new generation that meets specific needs to be distributed among all benefitting customers. In Section VIII.B, SCE describes the cost allocation treatment for each category of resource procured to meet the LCR need. Consistent with Public Utilities Code §365.1(c)(2)(A)-(B), prior Commission decisions,[47] and the LTPP Track 1 and Track 4 decisions[48] which authorized the LCR procurement to benefit all customers in the SCE service territory, SCE requests that its LCR procurement cost be allocated to all customers within the SCE service territory consistent with CAM principles. See Chapter VIII for further discussion on the recommended allocation of costs and benefits. As has been SCE's practice, SCE consulted with its CAM Group on a regular basis prior to, during, and after the close of the LCR RFO. Table IV-8 lists SCE's consultations with the CAM Group and the topic of each consultation.

SCE also briefed various members of Energy Division throughout the process on different aspects of the LCR RFO, including the shortlist and final selection, issues related to ES, debt

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[46] No SCE affiliate participated in SCE's LCR RFO.

[47] See D.06-07-029, D.07-09-044, D.08-09-012, D.11-05-005 and D.13-02-015.

[48] D.13-02-015 and D.14-03-004.

equivalency considerations, and EE/DR incrementality. In addition, SCE previewed information that was going to be presented at the CAM Group meetings with Energy Division personnel.

***Table IV-8***
***CAM Group Meetings***

| Date | Topic | Description of Information Provided to CAM |
|---|---|---|
| 2-Jul-13 | SCE's Local Capacity Requirements (LCR) Procurement Plan | LCR Procurement Plan |
| 9-Sep-13 | Launch of the LCR RFO | Presentation on the launch of the LCR RFO |
| 9-Dec-13 | LCR RFO Shortlist Process | Presentation on the process SCE is using to shortlist bidders |
| 23-Jan-14 | LCR RFO Shortlist | LCR RFO preliminary shortlist provided |
| 29-Jan-14 | LCR RFO Shortlist | Review of the final shortlist |
| 12-Mar-14 | Update on LCR RFO | Impacts of the CAISO's recent transmission studies on the LCR RFO |
| 3-Apr-14 | Update on LCR RFO | Updates to the shortlist based on CAISO changes in effectiveness factors |
| 17-Apr-14 | Update on LCR RFO | Demand Response – LCR incremental framework |
| 1-May-14 | Update on LCR RFO | Schedule update |
| 23-May-14 | Update on LCR RFO | Analysis of incremental energy efficiency |
| 19-Jun-14 | Update on LCR RFO | Final offer valuation and selection process |
| 25-Jul-14 | Update on LCR RFO | Debt equivalence issues and solutions |
| 3-Sep-14 | Update on LCR RFO | Update of offers and review of issues |
| 23-Sep-14 | LCR Final EE and DR Tranche Analysis | Energy efficiency and demand response incremental resources |
| 1-Oct-14 | Cost Allocation Plan for LCR RFO | Review of SCE proposal to allocate costs to all benefitting customers |
| 2-Oct-14 | LCR RFO Selection Process and Preliminary result<br>IE Presentation on his Independent Assessment<br>Capital Lease and Debt Equivalence | Presentations on the selection process and preliminary results, IE assessment, and capital lease/debt equivalence |
| 8-Oct-14 | Continuation of Selection Process and Preliminary Results | Continued discussion of capital lease and debt equivalence |
| 21-Oct-14 | LCR RFO Final Selection Results | Final selection methodology and results |
| 5-Nov-14 | LCR RFO Final Selection Results Update | Update to final selection methodology and results |

## I. Impact of Debt Equivalence on LCR RFO Contract Structure

### 1. Significance of Debt Equivalence

Debt equivalence arises from long-term contracts and other long-term financial commitments that are not included as debt on the balance sheet, but are viewed as debt by credit rating agencies. The fixed capacity payments of contracts or the adjusted all-in energy payments are considered to be debt equivalents by rating agencies because the buyer's (*i.e.*, SCE) payment obligations under the contract are fixed obligations and cannot be avoided without defaulting on the contract. These fixed obligations have a priority claim on a utility's cash flow. Such fixed obligations are one of the most important considerations in a credit rating analysis. The credit rating agencies pay careful attention to SCE's contracts, as they have a significant effect on the utility's credit rating and ultimately, SCE's cost of borrowing.

Although all three rating agencies consider debt equivalence in their credit rating determinations, Standard & Poor's ("S&P") places the greatest emphasis on debt equivalence and has published the most detailed explanation of its calculations, which involve calculating the net present value of future capacity payments or adjusted all-in energy payments and then multiplying that net present value by a risk factor that reflects the risk of recovery of those payments through the utility's rates. For SCE, S&P's current risk factor is 25 percent.[49] Even at a 25 percent risk factor, debt equivalents from the LCR RFO contracts[50] could be in the range of $1 billion.

Once debt equivalents are calculated, the rating agencies modify their calculations of the utility's capital structure and related credit statistics by adding the debt equivalents to the debt that is already on the utility's balance sheet. In addition, S&P imputes interest expense on the debt equivalence in cash flow calculations, offset by additional cash flow from imputed depreciation expense,[51] to measure the

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49 S&P assigns each utility a risk factor based on items such as the utility's regulatory structure and likelihood of recovering long-term contract costs in rates.

50 For the purposes of this sentence, the LCR RFO contracts include the contracts for both the Western LA Basin and Moorpark sub-area.

51 The interest expense reduces cash flow. The depreciation expense, calculated as the risk factor times the capacity payment, minus the imputed interest expense for the year, increases cash flow because it is a non-

(*Continued*)

impact of the debt equivalents on the utility's financial structure. S&P also adds other long-term obligations to the utility's balance sheets.

The overall effect of debt equivalence is to make SCE's balance sheet more leveraged and to reduce the quality of SCE's cash flow in credit rating calculations. If SCE's debt equivalents increase by a significant amount, it could result in a downgrade of SCE's credit rating at some future date. A credit rating downgrade would be harmful to SCE, its suppliers, and its customers, and would likely increase SCE's cost of issuing debt and preferred equity and SCE's collateral requirements and collateral costs. Customers would ultimately bear these higher costs. Further, SCE would have less favorable access to capital.[52] Generally, less favorable access to capital means higher financing costs. However, in times of financial crisis, SCE may be denied access to short-term financing, which could result in SCE being unable to meet its financial obligations in a timely manner. In addition, SCE's suppliers could be harmed because SCE would be a less creditworthy counterparty, making it more difficult for SCE's suppliers to obtain credit on favorable terms and conditions.

### 2. Seeking a Potential Solution to Minimize the Debt Equivalency Issue

Once a long-term contract has been negotiated, SCE performs a preliminary accounting assessment of that contract using generally accepted accounting principles. The primary considerations of this assessment include the negotiated contract language and SCE's valuation. The contract may fall into one of the following categories: (1) accrual accounting; (2) lease; (3) derivative; or (4) consolidation. Each of these categories results in different accounting treatment which may influence how a rating agency determines the debt equivalents associated with each contract as discussed above in

Continued from the previous page

cash expense. Imputed debt, imputed interest expense and imputed depreciation all impact key financial ratios reviewed by credit agencies in determining creditworthiness.

[52] For example, if a credit rating downgrade led to some or all of SCE's debt and preferred equity securities being downgraded below investment grade, many investment funds, such as pension funds, would no longer be able to purchase those securities and would have to divest the ones that they owned at the time of the downgrade.

Section IV.I.1. When performing its preliminary assessment of the contracts, SCE determined that its then-current form of GFG, IFOM ES, and BTM ES contracts would result in capital lease accounting treatment, which has an unacceptable level of debt equivalents.

In order to minimize the debt equivalency issue, SCE made the following changes to the structure of the contracts: (1) added an "Embedded Put Option" to GFG contracts for combined-cycle gas turbines ("CCGT") power plants and IFOM ES contracts; (2) converted GFG contracts for combustion turbines ("CTs") to fixed-price per unit RA-only contracts; and (3) modified the terms of the BTM ES contracts.

The contracts with the Embedded Put Option now contain a "put option" where the seller can transfer annual control of the energy rights to SCE at a "put" price that SCE can modify up until CPUC approval (as defined in the contract).[53] The inclusion of an "Embedded Put Option" results in lower debt equivalents than the original assessed capital lease accounting treatment.

The preliminary accounting assessment for the GFG contracts for CTs also resulted in capital lease accounting treatment with an unacceptable level of debt equivalents. The "Embedded Put Option" approach did not work for these contracts because they are peaker units that are not forecasted to run frequently and, therefore, are not expected to generate much energy output. The low output resulted in a low energy valuation which caused the contract to still be subject to capital lease accounting treatment, even with the "Embedded Put Option." Instead, SCE was able to restructure the GFG CT contracts to fixed-price per unit RA-only contracts. The accounting assessment for the restructured contract resulted in accrual accounting treatment and thus reduced the debt equivalence impact.

For BTM ES contracts, the preliminary accounting assessment also resulted in capital lease accounting treatment. SCE restructured the contracts to include a provision that allows the seller to add, remove or replace the assets associated with contracts as needed. Since the contract performance is not

[53] In the contracts, CPUC approval is thirty days after a Commission decision approving the agreement.

dependent on specified assets throughout the term of the contract, the contract accounting assessment indicates accrual accounting treatment is appropriate, which reduces the debt equivalence impact.[54]

[54] The contract solutions discussed in Section IV.I are based on current facts, circumstances and accounting literature. Any change to these variables prior to lease inception may drive changes to the debt equivalency treatment of the contracts and will need to be assessed accordingly.

# V.

# LCR RFO PARTICIPATION

## A. Summary of Solicitation Participation

This Chapter provides an overview of the following steps in the LCR RFO: (1) indicative offers submitted by bidders; (2) shortlist notification; (3) contract negotiations; and (4) final binding offers submitted.

### 1. Indicative Offer Submittal

SCE received a very robust set of indicative offers. In total, SCE received 1,136 offers from [redacted] bidders, spanning all of the technology types SCE solicited.[55] A summary of the indicative offers received is provided in Table V-9 below.[56]

***Table V-9***
***Summary of Indicative Offers***

| Product Type | [redacted] | Number of Offers |
|---|---|---|
| EE | | 181 |
| DR | | 113 |
| Renewable | | 11 |
| CHP | | 14 |
| DG | | 40 |
| ES | | 579 |
| GFG | | 198 |
| | **Total** | **1,136** |

Many of the counterparties who bid into the LCF RFO were new to SCE's structured procurement programs and required a significant amount of assistance with filling out the bid templates and providing all required information. This was further complicated by SCE soliciting products such as ES and EE aggregation for the first time. Thus, after receiving indicative offers, SCE went through a

[55] The 1,136 indicative offers includes offers for both the Western LA Basin and Moorpark sub-area.

[56] The number of counterparties in the table is greater than [redacted] because some counterparties submitted offers for multiple product types.

very intensive process of "curing" offers. Nearly every counterparty was contacted, and close to 80 percent of the offers were revised in some manner.

### 2. Shortlist Notification

SCE removed some projects from shortlist consideration because they did not meet the RFO requirements (*e.g.*, the most common non-conforming issue was proposed projects that were outside of the LCR region). In the LCR RFO, consistent with other procurement programs, SCE did not shortlist specific offers, but instead shortlisted entire counterparty/product combinations by comparing the best valued offer by counterparty/product. The rationale behind this practice is: (1) offers were likely going to change throughout the negotiation process; and (2) the main measure of workload for the SCE team is the counterparty/product combination, as each combination requires a separate document negotiation. Notwithstanding SCE's screening process, SCE shortlisted many counterparties/product types for the Western LA Basin.[57] Counterparties were only required to commit to certain offers and offer structures during the Indicative Offer and Final Offer phase. In between these two phases, counterparties were continuously refining offers, and even switched between in-front-of-the-meter and behind-the-meter resources. These changes occurred because counterparties continued to refine their projects as they became more knowledgeable about the feasibility and risk associated with them, and as a result of receiving feedback from SCE. As described in Section IV.H, SCE met with the CAM Group multiple times during the shortlist process.

### 3. Contract Negotiations

Shortlist notification was made on January 30, 2014, and form of contract negotiations commenced soon after. Per the revised LCR RFO schedule, the negotiation phase was originally

[57] Counterparties that were shortlisted for a product in one of the LCR areas, Western LA Basin or Moorpark, were usually shortlisted for the other area. This is because historically, a factor in how many projects to shortlist has been the amount of workload that the SCE team could handle. A large part of this workload is negotiations to reach agreement on a form of contract, and the assumption at shortlisting was that regardless of the geographic location of the project, a common form of the agreement could be used for Western LA Basin and Moorpark.

scheduled to end on August 29, 2014. However, as described in Section IV.E, a number of the complexities and challenges specific to the LCR RFO surfaced, which caused schedule delays.

During the negotiation phase, various counterparties withdrew or were removed from the solicitation. Table V-10 below lists those counterparties and the reason(s) why they could not continue to participate in the LCR RFO.

***Table V-10***
***Counterparties That Withdrew/Removed From Solicitation During Negotiations***

[redacted]

During this phase, SCE added two counterparty-product types not originally on the shortlist [redacted] in order to increase competition. [redacted]

[redacted]

#### 4. Final Binding Offer Submission

SCE received final offers on September 4, 2014. Table V-11 below summarizes the Western LA Basin offers.

*Table V-11*
*Summary of Western LA Basin Final Offers*

[redacted]

# VI.

## VALUATION PROCESS

SCE utilized a number of criteria during its evaluation and selection of offers. In accordance with D.04-12-048, SCE used a Least-Cost, Best Fit[58] methodology to value and award contracts in the LCR RFO. This Chapter is comprised of two main sections: (A) a description of SCE's market outlook methodology and (B) a description of SCE's valuation and selection methodology, including a discussion on the selected set of contracts that best met the constraints and preferences associated with SCE's LCR needs.

### A. Market Outlook Methodology

SCE prepared forecasts for RA capacity, electrical energy, ancillary services ("AS"), natural gas, and greenhouse gas ("GHG") compliance market prices. These price forecasts were used to model and prepare valuations of each offer received in the LCR RFO. [redacted] Specifically, SCE used market quotes as of [redacted] to set the market period and consultant forecasts for natural gas and GHG compliance prices which were key inputs used in the fundamental model to develop forecast electrical energy prices.

AS prices were developed using an econometric model which captures energy prices, upward and downward movement in energy prices and electricity demand, and hydroelectric production. AS

58 Methodology for taking into account both the cost of offers received from bidders and the extent to which the offers provide energy or other attributes needed by the buyer.

prices evolve over time in shape and magnitude to capture the increased ramping need due to increased intermittent renewable penetration.

SCE used the RA value adopted in D.11-12-018[59] for the Market Price Benchmark ("MPB") methodology used for calculating the Customer Responsibility Surcharge ("CRS") for departing customers as a reasonable proxy for the RA compliance value of LCR offers. D.11-12-018 adopted an RA value based on the most current calculation by the CEC of the going-forward cost of a combustion turbine,[60] currently set to $50.17/kW-year[61] ($4.18/kW-month). [redacted]

## B. Valuation Methodology & Selection Methodology

### 1. Overview

SCE's offer evaluation process follows Least-Cost, Best-Fit principles. SCE employs a net present value ("NPV") analysis when it evaluates offers submitted through an RFO. This methodology is consistent with evaluations performed by SCE in other solicitations, such as SCE's CHP RFOs, Renewables Portfolio Standard ("RPS") solicitations, and All-Source RFOs for energy and RA. 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.[62] 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

[59] D.11-12-018 at 108 (Conclusions of Law ("COL") 5)).

[60] *Id*.

[61] The CEC value is based on a 2009 study published in a January 2010 report. Going-forward cost components include insurance, ad valorum, and fixed operations & maintenance. The report can be found at: *http://www.energy.ca.gov/2009publications/CEC-200-2009-017/CEC-200-2009-017-SF.PDF*.

[62] SCE did not apply any locational adjustments for congestion or losses for the LCR RFO valuation as all bids were in the same local area.

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.

The benchmark for determining cost-effectiveness (*i.e.*, the resource's market value forecast minus the costs required to receive these benefits, plus any other value that can be attributed to the resource, discounted at 10 percent) is the calculated NPV of the offer. This NPV was the cost metric that SCE used in the selection process and its elements are described below.

### 2. <u>Contract Benefits</u>

#### a) <u>Energy and Ancillary Service Benefits</u>

##### (1) <u>Energy Efficiency</u>

Energy efficiency bidders provide SCE with the each offer's expected useful life and a typical meteorological year ("TMY") hourly energy savings profile (versus codes and standards). The offer's energy benefits are calculated by multiplying each month's total time-of-use ("TOU")-period TMY energy savings by its respective TOU-period average energy price forecast. Since EE benefits are derived from load reductions, the energy benefits are grossed up by SCE's Transmission & Distribution line loss factor of [redacted] percent to reflect avoided line losses.

##### (2) <u>Demand Response and Behind the Meter Energy Storage</u>

For dispatchable demand response resources and BTM ES, energy benefits are calculated through a dispatch simulation that projects the economically beneficial periods when SCE would pay for a reduction in load. This is done by calculating each offer's theoretical maximum annual net revenues given the specified daily dispatch costs and limits (*i.e.*, minimum and maximum duration, maximum events per day, available hours, and energy rate), monthly availability and dispatch maximums, and annual dispatch maximums. This simulation is performed on multiple power price scenarios, and results in an expected monthly energy benefit forecast associated with utilizing the demand response resource. Since demand response and BTM ES benefits are derived from load reductions, the energy benefits are grossed up by SCE's Transmission & Distribution line loss factor of [redacted] percent to reflect avoided line losses.[63]

(3) In Front of the Meter Energy Storage

To maintain consistency of valuations across different technologies, SCE adapted its approach to valuing dispatchable thermal resources for use in the valuation of IFOM ES assets. Specifically, SCE developed a proprietary economic dispatch model to determine optimal charge and dispatch of IFOM energy storage devices. Inputs into this model include forecasted price streams for energy and ancillary services and the contractual terms, such as VOM charges and operational parameters, of the storage device. Typical operational parameters for the storage device include maximum power output, maximum power input, maximum and minimum storage quantities, and device efficiency. The output of the model is the optimal operation and revenue earned by using the device to arbitrage prices through time based on SCE's forecasts of market conditions (*i.e.,* load the device when prices are low and dispatch the device when prices are high). The model is coupled with a Monte Carlo price simulator that generates hourly pricing scenarios across the time horizon being valued. A forecast of energy revenue is obtained for each scenario, yielding multiple revenue outcomes. SCE averages and discounts the outcomes to obtain a single energy value and AS value.

(4) Gas-Fired Generation

For dispatchable thermal resources, SCE utilized a fundamental production-cost model (ProSym) combined with a stochastic price process via a Monte Carlo simulation, to value the energy and AS benefits of the generating units. Inputs to the fundamental model include unit characteristics such as capacity, heat rate curve, ramp rate, start fuel and start cost, minimum and maximum run-time, VOM cost, GHG cost, fuel cost, and emission constraints, among others. SCE uses the economic dispatch principle, wherein a unit is simulated to dispatch if its forecasted benefits exceed its costs (*i.e.*, if it is "in

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63 DR resources are supplied at the customer meter level, and therefore, eliminate the need to account for T&D line losses. The "Transmission & Distribution line loss factor" captures this benefit and is calculated based on the methodology described in D.10-06-036 at 40.

the money"). ProSym compares the forecasted cost of running a unit against energy and AS price forecasts to determine whether a unit is in the money.

SCE creates an expansive "lookup" library of dispatch results to avoid the need to perform multiple runs for each analysis. [redacted] SCE then deploys a stochastic Monte Carlo simulation process to generate many gas price and implied market heat rate pairs, using blended power and gas price curves derived from market and fundamental models as the expected case, and by applying a volatility process on top of the blended price forecasts to create a distribution of price outcomes. The volatility process estimates correlation, volatility, mean reversion, stochastic volatility and seasonal parameters. The simulated price pairs are used to "look up" the forecasted gross energy benefits and costs from the dispatch library identified above. SCE defines the expected energy and AS benefits as the average of the simulated cases. This process allows SCE to value both the intrinsic and extrinsic (optionality) value of the resource.

(5) <u>Other Resources</u>

Finally, for must-take and baseload resources, SCE calculated the energy benefits of an offer based on the estimated market value of energy using the offer's expected generation or delivery profile. Since SCE does not have dispatch rights to these types of resources, production cost modeling and Monte Carlo simulation is unnecessary. In addition, these resources receive no AS value because they cannot participate in the CAISO's AS markets.

b) <u>Resource Adequacy ("RA") Capacity Benefits</u>

RA compliance capacity benefits are derived by first developing a forecast of expected forward RA compliance prices and then applying these forecasted prices to the total RA capacity provided by the offer. In its Procurement Plan, SCE explained that it would apply LEFs to the RA value. Additionally, the Track 1 decision required SCE to use the most up to date LEFs in its valuation. Because Southwest sub-area resources were considered most effective, only Western Central and Northwest sub-areas IFOM ES offers received an RA value adjustment based on their LEF. The adjustment factor was equal to one minus the difference between the project's LEF and the 0.717 LEF of the Southwest sub-area. SCE received IFOM ES offers that were located only in the Southwest and Northwest sub-areas of the Western LA Basin. Consequently, only offers located in the Northwest sub-area (which has an LEF of 0.136) received an LEF RA adjustment factor. This resulted in Northwest IFOM ES offers receiving 41.9 percent (1 - (0.717 - 0.136)) of full RA value in SCE's calculation of RA benefits.

To determine the RA capacity provided by each of the offers, SCE used current RA counting rules where applicable, and applied similar rules where RA counting rules have not been established. The Table VI-12 below summarizes how the RA capacity was determined for each offer type:

***Table VI-12***
***RA Capacity Determination by Product***

<table>
<tr><th>Offer Type</th><th>RA Capacity – Determination</th></tr>
<tr><td>Gas-Fired Generation</td><td>RA capacity equals monthly contract capacity</td></tr>
<tr><td>Energy Storage</td><td>RA capacity equals monthly contract capacity</td></tr>
<tr><td>Energy Efficiency</td><td>RA quantities are calculated separately for summer and non-summer months. Non-summer month RA quantities are calculated by averaging the TMY hourly energy savings from 2 to 5 PM coincident with SCE's highest three forecasted peak demand days (nine hours total for each month). Summer month RA quantities are set equal to the guaranteed "capacity" savings as specified in the offer.<br><br>Since EE benefits are derived from load reductions, RA benefits are grossed up by the T&D loss factor in addition to the 15 percent reserve margin requirement.</td></tr>
<tr><td>Solar Rooftop</td><td>RA quantities were calculated using the exceedance approach. Since the technology was solar, SCE used a 70% exceedance level and the following hours (from the offer's TMY delivery profile) for observations:<br><br><table><tr><td>Jan–Mar, Nov and Dec:</td><td>HE17 - HE21[1] (4:00 p.m. - 9:00 p.m.)</td></tr><tr><td>Apr–Oct:</td><td>HE14 - HE18 (1:00 p.m. - 6:00 p.m.)</td></tr></table><br>Since Rooftop solar offers are all behind-the-meter, and therefore load reductions, RA benefits are grossed up by the T&D loss factor and 15 percent reserve margin requirement.</td></tr>
<tr><td>CHP</td><td>RA quantities for the first two years of the contract term were set equal to the offer's firm capacity multiplied by the 2014 monthly technology factors for Cogeneration resources. The remaining term was equal to the minimum of the firm contract capacity and the specified average peak-period energy deliveries.<br><br>Since CHP offers are all behind-the-meter, and therefore load reductions, RA benefits are grossed up by the T&D loss factor and 15 percent reserve margin requirement.</td></tr>
<tr><td>Demand Response</td><td>RA quantities are equal to the monthly contract quantity, or load reduction amount, provided in each offer.<br><br>Since these benefits are derived from load reductions, RA benefits are grossed up by the T&D loss factor and 15 percent reserve margin requirement.</td></tr>
<tr><td colspan="2">1 HE indicates "hour ending."</td></tr>
</table>

### 3. **Contract Costs**

a) Dispatch and Energy Costs

(1) Demand Response and Behind the Meter Energy Storage

For dispatchable DR and BTM ES resources, the "dispatch" or variable costs ($/MWh) are calculated by projecting the economically beneficial periods when SCE would pay for a reduction in load using the dispatch process described above in Section VI.B.2.a)(4) when calculating energy value.

(2) In Front of the Meter Energy Storage

For dispatchable IFOM ES resources, charging and VOM costs are accounted for in the dispatch optimization model.

(3) Gas-Fired Generation

For dispatchable thermal resources, dispatch costs include unit start costs, VOM costs, GHG compliance cost, and fuel costs. Start costs include the fixed cost of starting a unit, and are differentiated by hot and cold starts, depending on how long the unit has been simulated to be offline. VOM costs are costs which are directly proportional to the output of the unit, measured in $/MWh. GHG compliance cost is the California Cap & Trade compliance cost of obtaining the allowances for a unit emitting GHG. Fuel costs include the variable cost of generating power and the fixed cost of the required fuel amount used to start up a unit. These cost components are accounted for in the ProSym production cost modeling and are used to make the simulated economic dispatch decisions.

(4) Other Resources

For must-take and baseload resources, energy costs can include fuel costs (as indicated by a heat rate), VOM, and GHG compliance costs, or an all-in energy price in dollars per Megawatt-hour ("MWh") as is typically used for RPS resources.

b) Capacity Payments

Capacity payments represent the total fixed contract payments SCE is expected to make under the contract for delivery of the energy and capacity benefits.

c) Debt Equivalents

Debt equivalents is the term used by credit rating agencies to describe the fixed financial obligation resulting from long-term contracts (see Section IV.I for more detail). Pursuant to D.04-12-048 and D.08-11-008, the Commission permits the utilities to recognize in their valuation processes the cost associated with the effect debt equivalence has on the utilities' credit quality and cost of borrowing.[64] Consistent with these decisions, SCE considers debt equivalence in its valuation process using the 20 percent risk factor authorized by the Commission.

d) Transmission Cost

For IFOM projects that either (1) do not have an existing interconnection to the electric system, or (2) have an existing interconnection, but do not have an approved expansion to an existing facility, system transmission network upgrade costs are based on the most recent interconnection study from the CAISO. For projects with no interconnection study, but with an offer providing SCE the right to terminate if system transmission network upgrade costs exceed a specified amount, transmission costs are based on the specified transmission network upgrade amount.

e) Greenhouse Gas Cost

For any offer that requires customers to absorb GHG compliance costs, SCE will assess a GHG cost to the offer based on SCE's forecast of GHG prices and the offer's forecasted amount of GHG emissions.

f) Put Option Cost for IFOM ES and GFG

For the specific GFG resources and IFOM ES which would have a dispatch put option embedded in their contract, SCE calculated a put option cost for use in the valuation analysis. As described above, SCE uses a distribution analysis to derive the energy and AS value associated with dispatchable units, such as GFG and IFOM ES. SCE used these results to determine the value of the Embedded Put Option to the seller, and hence the cost to the customer. In order to derive the put option value, SCE first

[64] D.04-12-048 at 243 (OP 22) and D.08-11-008 at 38 (OP 1.a).

calculated the strike price for each year of the delivery period by setting the strike price equal [redacted] of the value distribution for the respective resource. SCE then calculated the conditional expected returns above the [redacted] by averaging the distribution results from the [redacted]. The put option cost to the customer was set as the difference between these two values (conditional expected returns minus strike price) multiplied by [redacted] to reflect the probability of the value being realized).

g) <u>Other Quantitative Considerations</u>[65]

One counterparty had additional incremental cost impacts to SCE due to the offers that they had submitted. [redacted] had proposed DR programs targeting residential customers that would require system upgrades and ongoing administrative and operational costs. SCE included these costs in its valuation of [redacted] offers.

### 4. <u>Quantitative Benefits Summary</u>

As explained above, SCE calculated the quantitative benefits of offers by subtracting the present value of expected costs from the present value of expected benefits to determine the expected NPV of the offer.

### 5. <u>Qualitative Assessment</u>

In addition to the benefits and costs quantified during the evaluation, SCE assessed non-quantifiable characteristics of each offer by conducting an analysis of each project's qualitative attributes. SCE considered qualitative characteristics in determining the final selection. These characteristics included:

- Locational Effectiveness, as determined through CAISO LEFs
- Permitting and interconnection

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65 [redacted]

- Environmental and permitting status
- Electrical interconnection status
- Fuel interconnection and source

- Pre-development milestones
  - Project financing status
  - Project development experience
  - Emissions performance standards
- Development milestones
  - Site control
  - Reasonableness of commercial operation date
- Risks associated with the resource type
- Portfolio fit of energy, capacity, and term

**6. <u>Selection Constraints</u>**

SCE performed a least-cost, best-fit optimization selection by imposing constraints over a series of iterative optimizations. Then, SCE selected the set of contracts that satisfied the constraints while providing the most cost-effective valuation. To do this, SCE developed an optimization model that selects the highest NPV contracts subject to the constraints that are further described below. Inputs into the optimization model include the NPV of all contracts offered into the RFO, relevant contract information, and constraint information. There are three sources of constraints: (1) regulatory limits, (2) SCE operations, and (3) counterparty/project specific requirements.

Regulatory limits included minimum and maximum allowable purchase quantities for different asset categories (*e.g.*, fossil fuel, ES, Preferred Resources). SCE specific constraints included information derived from its offer template which allowed for inclusivity and exclusivity among offers. SCE also set additional constraints to consider viability, seller concentration and/or to limit exposure to certain technologies. For example, SCE set limits on the amount of DR offers that could be selected in a particular area based on the expected potential for DR in that area to avoid selecting offers that would be in excess of the potential load reductions from the same customer population. Counterparty limits are set by each counterparty's offer structure.

Once the minimum constraints were defined, the optimization model output a set of contracts with the greatest value that satisfied the constraint set. SCE reviewed the results and modified its constraint set to reflect qualitative determinations (*e.g.*, technology concentration) and generated another output set. SCE continued to iterate the generation of output sets by adjusting constraints based on qualitative assessments until a final selection set was selected.

## C. Valuation and Selection Optimization Results

### 1. Overview

SCE considered approximately [redacted] for final selection. Contract durations ranged from 4 to 30 years, with the earliest start date being January 2016 and the latest end date being June 2048. [redacted] Using these price outlooks, SCE calculated NPVs for each offer using the applicable methodology as described in Section VI.B.

Due to the complexities and time constraints associated with modeling and running GFG, DR, BTM ES, and IFOM ES offers through the valuation process, [redacted]

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[redacted]

[redacted] A summary of the number of offers evaluated by technology is provided in Table VI-13 below.

***Table VI-13***
***Offers Evaluated by Category***

[redacted]

### 2. <u>Valuation Results</u>[67]

In addition to the NPV that was calculated for each offer and used in the selection optimization process, SCE developed three normalization metrics to be applied to each offer to support decision making for the LCR RFO selection process:

1) Average Contract kW-month - defined as the average contract quantity (kW-month) over the delivery term.
2) RA kW-month - defined as the average RA quantity (kW-month[68]) over the delivery term.
3) LCR kW – defined as the August 2021 RA quantity (kW). SCE used this value in measuring whether SCE met its LCR RFO procurement requirements.

Next, SCE converted the NPV results for each offer into three premiums by multiplying each by minus one and then dividing by the respective normalization values. This resulted in the following normalized metrics:

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67 The results of the valuation analysis for all offers can be found in SCE's workpapers.

68 This value could be higher or lower than the contracted kW due to the RA capacity counting rules described in Section VI.B.2.b).

1) Discounted Premium per contract kW-month.

2) Discounted Premium per RA kW-month.

3) Discounted Premium per LCR kW.

A summary of the valuation results showing the minimum, average and maximum metric for each resource type bidding into the LA Basin is provided in Table VI-14 below.[69]

***Table VI-14***
***Valuation Metrics by Category***

[redacted]

As can be seen in Table VI-14 above, offer valuations ranged from negative premiums to positive premiums.[70] [redacted]

In addition, many of the offers were offered on a mutually inclusive basis (*i.e.*, if SCE selects one of these offers, it must take the other inclusive offer(s)). This constraint is the primary reason that a simple rank ordering selection process by category is not feasible. In some cases, offers were linked

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[69] The full valuation results and metrics for each offer can be found in SCE's workpapers.

[70] A negative premium equates to a positive NPV, meaning, based on the price forecast used, the forecasted benefits of the contract outweigh the costs. A positive premium equates to a negative NPV, meaning, based on the price forecast used, the forecasted costs of the contract outweigh the forecasted benefit.

[71] [redacted]

across resource types. In order to develop an optimal portfolio selection, given the regulatory and counterparty constraints, SCE developed and executed a selection optimization process that maximized the portfolio NPV while controlling for specific constraints using qualitative criteria.

### 3. Summary of Portfolio Selections

Prior to execution of the selection process, SCE completed a review of the valuation results and confirmed that: (1) the results were internally consistent, (2) the valuation process had been executed consistently, and (3) the process was executed as planned and communicated to SCE management and the CAM Group. SCE then executed its selection process using a mathematical optimization process. SCE iterated through several selection sets considering both the quantitative and qualitative aspects of the selections before finalizing its recommendations. Each new selection set adjusted both the optimization constraints, and in some cases, the offers and packages included in the process. Key qualitative considerations included:

- Amount of IFOM ES MW Selected: As discussed in Section IV.E, SCE has some concerns related to IFOM ES and thus elected to limit the amount of procurement of IFOM ES in the optimization. In addition, SCE's valuation of IFOM ES offers assumed unconstrained operations in CAISO markets leading to significant assessed AS revenues from participating in AS markets during all hours. Current uncertainty around the interconnection of IFOM ES, which may result in restrictions on charging ability during peak hours, and uncertainty on how IFOM ES will actually participate in CAISO markets, warranted SCE to assume that its IFOM ES valuation results may be higher than what will be achieved. Uncertainty around the valuation results also created additional risk for potential capital lease accounting and higher amounts of debt equivalence, as the valuation analysis is being used to set the strike prices for the Embedded Put Option.
- Site Concentration for GFG: SCE was concerned that having most of the GFG at one site would not be optimal. SCE also recognized that the valuation results of some of the GFG resources were very close and within the error bounds of the model, which supported imposing qualitative factors into the selection of the optimization constraints.

- Amount of Preferred Resources Pilot ("PRP")[72] MW Selected: SCE had specified in its RFO instructions that it had a preference for resources in the Johanna or Santiago sub-areas to support its PRP.
- Two-Hour vs. Four-Hour Resources: SCE worked with the CAISO to develop a quantity limit of resources that only provide two hours of energy discharge capability to meet the LCR need.[73] As discussed below, SCE ultimately decided not to procure two-hour resources because CAISO had not studied their application as System RA resources.
- Cost of Meeting the Minimum Targets: With counterparty exclusivity constraints, less than 700 MW of Preferred Resources could be selected.[74] This amount was a little larger than the minimum target for Preferred Resources and, as more Preferred Resources were selected, the incremental costs of these resources increased greatly. See chart below. As such, SCE chose not to meet the Track 1 and 4 decisions' minimum Preferred Resource amount in this solicitation.

72 SCE's PRP is a significant-scale, multiyear pilot to investigate and demonstrate how the integrated use of Preferred Resources may simultaneously meet demands for electricity in the PRP target region. See Section VII.B.1 for additional information on the PRP.

73 Current CAISO and RA rules provide that in order to qualify as an RA resource, the resource must be able to provide energy over a continuous four-hour period.

74 Excluding IFOM ES and two-hour products.

***Figure VI-6***
***Preferred Resource Supply Curve (Excluding IFOM ES)***

[redacted]

Table VI-15 below shows the key constraints that were used or adjusted during the development of the selection sets in SCE's iterative optimization process.

*Table VI-15*
*Selection Optimization Constraints*

| Constraint | Description |
|---|---|
| Minimum GFG | Minimum GFG MW value that must be included in the selection set. |
| Maximum GFG | Maximum GFG MW value that could be included in the selection set. |
| Minimum Preferred Resources/ES | Minimum Preferred Resources/Storage MW value that must be included in the selection set. |
| Minimum Total Procurement | Minimum Total MW value that must be included in the selection set. |
| Maximum Total Procurement | Maximum Total MW value that could be included in the selection set. |
| Maximum 2-hour product | Maximum 2-hour product MW value that could be included in the selection set. |
| Minimum Storage | Minimum Storage MW value that must be included in the selection set. Included both IFOM and BTM ES products. |
| Maximum IFOM ES | Maximum IFOM ES MW value that could be included in the selection set. |
| Minimum PRP | Minimum amount of PRP eligible MW to be included in the selection set. |

SCE's selection optimization tool allowed for the generation of a single selection set or multiple selection sets called "draws" based on increments of LCR MW[75] selected between the minimum and maximum total procurement levels. SCE set different LCR MW target levels and used its optimization tool to generate selection sets and a decision document that summarized the selection sets. The summary included a list of the selected offers for each draw in the selection set, MW selected in each category, the normalized metrics discussed above, cash flow items, marginal costs, summary statistics, MW build-out by year, and other information. After reviewing the summary, SCE configured the optimization program in order to provide better cost and portfolio fit outcomes. SCE went through several iterations of this process yielding different optimization configurations that are summarized below.

[75] LCR MW is defined as the forecasted August 2021 net qualifying capacity ("NQC").

a) Selection Sets

Using the optimization tool, SCE set its initial constraints based on the minimum and maximum levels of procurement authorized in the LTPP Track 1 and 4 decisions. Those constraints are listed in Table VI-16 below:

***Table VI-16***
***Initial Selection Constraints***

| Min GFG | Max GFG | Min Pref. Res./ES | Min Total | Max Total | Max 2-hour | Min ES | Max IFOM ES | Min PRP |
|---|---|---|---|---|---|---|---|---|
| 1000 | 1500 | 600 | 1900 | 2500 | 150 | 50 | N/A | N/A |

The optimization tool created a selection set consisting of 25 draws in 25 MW increments between 1,900 and 2,500 MW.[76] While all draws were consistent with the specified targets, the resources selected in each of the draws caused some concerns from a best-fit perspective. All draws contained significant amounts of IFOM ES (Draw 1 had over 400 MW and Draw 25 had over 900 MW). [redacted] Based on these initial observations, SCE performed several iterations of constraints, making adjustments to the procurement levels to arrive at its final selection set. SCE sets forth these final constraints and the rational for each below.

First, SCE limited the amount of IFOM ES that could be selected to 100 MW. The rational for limiting IFOM ES is discussed in Sections IV.E.2 and IV.E.3, and earlier in this section. This constraint resulted in the selection of the maximum amount of IFOM ES (*i.e.*, 100 MW). SCE ran sensitivities on the amount of IFOM ES selected ranging from 0 MW to 100 MW. Procuring lower amounts of IFOM

[76] SCE's decision document for this selection set can be found in SCE's workpapers.

ES resulted in the additional selection of Preferred Resources/ES MW at a significant cost, as these alternatives required the procurement of increasingly higher-cost Preferred Resources (see Figure VI-6 above). In addition, the 100 MW selection of IFOM ES resulted in a single resource at the existing Alamitos site that was connected to the transmission[77] system at 220kV, in an area where there was less likelihood of charging restrictions and congestion. SCE decided that the maximum 100 MW IFOM ES constraint provided an appropriate balance between financial impacts and technology concentrations.

Second, with respect to GFG, SCE removed the initial selected packaged GFG offers for the Alamitos site to allow other combinations of offers to be selected. Initially, in conjunction with the IFOM ES constraint, the optimization selected a higher amount of GFG. This was largely due to the limitation on IFOM ES and GFG being the next economic resource in terms of NPV. After SCE removed the selected packaged offers for the Alamitos site, SCE observed that the diversity of GFG selections was greatly improved versus the initial selection set. While there was still GFG selected at the AES Alamitos site, it had been reduced from 1280 to 640 MW in all draws. However, other GFG sites and counterparties were also selected in a number of the optimization runs. SCE eventually selected an optimization set with 644 MW of GFG at the AES Huntington Beach site with 6,600 run hours per year, 640 MW of GFG at the AES Alamitos site with 4,600 run hours per year, and 98 MW of GFG peakers at a greenfield site location connected to Barre sub-station through a WMDVBE supplier. The impact of selecting the Alamitos and Huntington Beach site over the just the Alamitos site was a modest increase in the premium [redacted] combined-cycle resources, and is reasonable given the diversity and optionality created by having two brownfield sites developed versus one, and the Huntington Beach site has the most run-hours possible.

[77] SCE's concerns around IFOM ES were exacerbated by distribution level connections.

Third, SCE focused on maximizing the amount or PRP eligible[78] MW selected to support the PRP with new Preferred Resources that could be measured and assessed with respect to providing reliability in the Johanna/Santiago sub-areas. The initial selection set included 58 MW of PRP eligible MW relative to a total potential of 91 MW. Based on sensitivity analysis, SCE determined that 66 MW of PRP eligible MW was optimal and cost competitive. The premium increase per LCR kW between moving from 58 MW to 66 MW of PRP eligible MW was [redacted].

Fourth, SCE incrementally added back into its selection set a negative premium Tranche 4 EE offer located in the Johanna/Santiago sub-area that was eligible for the PRP. The IE identified that the EE tranche analysis, as described above in Section IV.F., had excluded some offers that were eligible for the PRP and were very close to the Tranche 3 cut-off point. [redacted][79] and there was a PRP eligible offer for [redacted] SCE decided to pull this offer back into the selection set for two reasons: (1) it was located in the PRP area and started deliveries prior to October 2017; and (2) [redacted] Including this 5.55 MW offer increased the amount of PRP eligible MW and improved the overall premium for the selection set from [redacted]. While there were other PRP eligible MW excluded due to the tranche analysis, none had a negative premium.

Fifth, SCE eventually excluded two-hour products from the final selection set because the CAISO had not conducted analysis to determine the effectiveness of two-hour products in meeting a System RA need. The RA counting rules require that dispatchable resources be able to provide energy onto the grid for a continuous four-hour period in order to qualify as an RA resource. SCE required

[78] For the purposes of the LCR selection process, PRP eligible MW were defined as LCR MW of Preferred Resources located at either the Johanna or Santiago substation service area with a COD prior to October 2017.

[79] The cut-off represented an estimate of the cost in 2015 $/kW for a portfolio of EE programs with similar characteristics to the submitted offers.

these resources to bid four-hour products, but also allowed them to bid two-hour products to determine whether a large enough cost savings existed to pursue a change in the RA rules. SCE conducted a sensitivity excluding two-hour products from the selection set. The new optimization resulted in a selection in which four-hour products replaced two-hour products at a slightly higher cost. [redacted]

Finally, SCE also excluded three-hour Permanent Load Shift ("PLS") products from its final selection set. SCE initially included the three-hour PLS products, but then questioned whether there was value in moving to the more flexible four-hour PLS resources. SCE conducted a sensitivity analysis excluding the three-hour resources from the optimization selection set, thus allowing the optimization to select the next best resource(s). The optimization selected 28.6 MW of four-hour PLS product. [redacted] This is well within the error bands of the valuation process and thus the two selections were essentially equivalent. The final set of constraints was set as follows:

***Table VI-17***
***Final Selection Constraints***

| Min GFG | Max GFG | Min Pref Res./ES | Min Total | Max Total | Max 2-hour | Min ES | Max IFOM ES | Min PRP |
|---|---|---|---|---|---|---|---|---|
| 1000 | 1500 | 600 | 1975 | 2000 | 0 | 50 | 100 | 66 |

The optimization tool was used to create a single draw selection set consistent with SCE's final optimization constraints. SCE's decision document for this selection set can be found in SCE's workpapers. The optimized selection set met all of the targets specified in the constraints and selected a total of 1,989 MW, consisting of 343 MW of non-storage Preferred Resources, 100 MW of IFOM ES, and 164 MW of BTM ES, for a total of 607 MW of Preferred Resources/ES and 1,382 MW of GFG (composed of 1,284 MW of CCGT and 98 MW of peakers/CTs). The selection set also included 75 MW of PRP resources beginning delivery in 2017, with a build-out schedule increasing to 94 MW by 2021. The total NPV for the selection set was [redacted] with a total nominal cost of [redacted] The final premium per LCR kW was [redacted]

During the development of this recommended selection set it was identified that the selected GFG peakers would trigger debt equivalence issues, regardless of the inclusion of the Embedded Put Option. The energy and AS value[80] associated with these low utilization peakers was too low and did not represent more than a minor[81] amount of the output. To minimize the impact of these contracts on its balance sheet, SCE structured the contract as a fixed price RA contract. Such contract form is not a lease commitment and therefore minimizes the impact on SCE's credit rating. In consultation with the IE, SCE approached the impacted counterparty to request updated offers for RA only contracts for the GFG peaker offers. [redacted]

As SCE prepared to notify counterparties of their contract awards, [redacted] creating a deficit in meeting the 600 MW regulatory minimum for the Preferred Resource/ES category. Given that there were no cost competitive options remaining to meet the 600 MW minimum for Preferred Resources and ES, SCE removed two other packaged offers totaling 50 MW because it was determined that more cost effective options could be secured later, given that SCE would have to conduct additional LCR procurement to meet its 600 MW minimum requirement for

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[80] The energy and AS value represented approximately [redacted] of the total output in dollars.

[81] A minor amount was defined a 10% of total contract payments for the purposes of the accounting assessment.

Preferred Resources and ES. [redacted]

As a result of the loss of the [redacted] offers and SCE's removal of an additional 50 MW of Preferred Resources, SCE's final awarded selection set included a total of 1,883 MW with 237 MW of non-storage Preferred Resources, 100 MW of IFOM ES, 164 MW of BTM ES, and 1,382 MW of GFG. The final selection included a slightly lower level of PRP resources than what SCE targeted because of the withdrawn offers; 70 MW beginning delivery in 2017 and building up to 89 MW by 2021. The total NPV for the selection set was [redacted] with a total nominal cost of [redacted]. The final premium per LCR kW was [redacted] The selected offers are described in more detail in Chapter VII. A summary of the selection sets discussed above is provided in Table VI-18 below showing the progression of SCE's selection process and final award.

***Table VI-18***
***Selection Progression – Key Metrics***

[redacted]

# VII.

# SOLICITATION RESULTS

## A. Summary of Selected Offers

SCE selected 60 Preferred Resource contracts and three GFG contracts. Within the Preferred Resources category, SCE selected 23 contracts for ES, one of which was for IFOM ES. Table VII-19 summarizes the LCR MW[82] procured by product category. Additional detail for each category is provided below.

***Table VII-19***
***Summary of Selected Offers***

| Product Category | Total Contracts | Max Quantity (LCR MW) |
|---|---|---|
| **Preferred Resources and ES** | | |
| EE | 26 | 124.04 |
| DR | 7 | 75.00 |
| Renewable DG | 4 | 37.92 |
| ES | 23 | 263.64 |
| **Total Preferred Resources and ES** | **60** | **500.60** |
| **GFG Resources** | | |
| **GFG** | **3** | **1,382.00** |
| **Total Preferred Resources, ES, and GFG** | **63** | **1,882.60** |

## B. Description of Selected Offers

### 1. Preferred Resources

In this competitive solicitation, SCE adhered to and selected resources consistent with the Loading Order of the State's Energy Action Plan II. This resulted in 60 contracts for EE, DR, Renewable DG, BTM ES, and IFOM ES for a total of 500.60 LCR MW. The breakdown of the resources can be seen in Table VII-20.

[82] To clarify, the LCR MW are a resource's contribution to the LCR need in August 2021. This may differ from the MW quantity specified in the contract.

***Table VII-20***
***Summary of Preferred Resource Selected Offers***

| Product Category | Counterparty | Total Contracts | Max Quantity (LCR MW) |
|---|---|---|---|
| EE | • Onsite Energy Corporation<br>• Sterling Analytics LLC<br>• NRG Energy Efficiency-L LLC<br>• NRG Energy Efficiency-P LLC | 26 | 124.04 |
| DR | • NRG Distributed Generation PR LLC<br>• NRG Curtailment Solutions LLC | 7 | 75.00 |
| Renewable DG | • Solar Star California XXXV, LLC<br>• Solar Star California XXXVI, LLC<br>• Solar Star California XXXVII, LLC<br>• Solar Star California XXXVIII, LLC | 4 | 37.92 |
| ES | • AES ES Alamitos, LLC<br>• Ice Bear SPV #1, LLC<br>• Hybrid-Electric Building Technologies Irvine 1, LLC<br>• Hybrid-Electric Building Technologies Irvine 2, LLC<br>• Hybrid-Electric Building Technologies West Los Angeles 1, LLC<br>• Hybrid-Electric Building Technologies West Los Angeles 2, LLC<br>• Stem Energy Southern California, LLC | 23 | 263.64 |
| | **Total Preferred Resources (including ES)** | **60** | **500.60** |

As stated in Section VI.C.3, a qualitative consideration in the selection process was the amount of PRP MW selected. SCE specified in its RFO instructions that it had a preference for Preferred Resources in the Johanna or Santiago areas to support its PRP. SCE chose the Johanna and Santiago sub-areas in the Southwest sub-area of the Western LA Basin because the Southwest sub-area is the area most impacted by the permanent closure of SONGS. To assess the capabilities of Preferred Resources, SCE, as part of the PRP, will design, acquire, and measure a diverse portfolio of Preferred Resources that will meet the area's power needs, while informing the development of the grid of the future and contributing toward California's progressive environmental and renewable energy goals. Through the PRP, SCE seeks to provide customers, regulators, electric system operators, transmission planners, procurement entities, and stakeholders, greater understanding about the ability and availability of Preferred Resources to perform where and when needed to meet local reliability, while ensuring grid stability and resiliency. As identified below, several of the Preferred Resource offers selected are located in the Johanna/Santiago area.

a) Energy Efficiency

SCE selected 26 EE offers from three different counterparties representing a total of 124.04 MW of savings.

SCE created a new EE contract for the LCR RFO where the seller commits to achieve a specified quantity of energy (kWh) and capacity (kW) savings through installation of specified energy efficiency measures at customers' sites. In the contract, the sellers generally identified the types of measures they intend to deploy as well as the customer class they intend to target. However, for the most part, specific customers had not yet been identified at the time of contract execution.

Per the agreement, the seller is obligated to achieve energy savings during three distinct periods: Summer-On-Peak, Summer Off-Peak, and Winter On-Peak. In addition, the seller is obligated to meet certain capacity savings. Failure to meet these savings reduces payment under the contract.

The parties rely on an independent evaluator to measure savings. The independent evaluator is hired by the seller, although SCE has discretion to determine the acceptability of the seller's choice. The independent evaluator will create a measurement and verification ("M&V") plan, subject to SCE's review, in accordance with the M&V protocol included in the contract. The independent evaluator will perform the M&V consistent with the M&V Plan, and will ultimately create a report setting forth energy and capacity savings for purposes of determining payment under the contract. If SCE does not reasonably agree with the M&V report, SCE has the right to hire its own independent evaluator whose report will be used to assess performance under the contract. This process is performed upon installation of all of the measures, and allows for SCE to require additional M&V measurements over the term of the agreement.

The EE contracts also contain a delivery date security requirement of $22.50/kW and include provisions where the total payment is made over a four- to six-year period to ensure some payment is made under the contract in 2021 when the resources are first needed. As described in Section IV.F, SCE selected contracts that were incremental per the EE tranche analysis performed by SCE. [redacted] which is discussed in further detail below.

## *Table VII-21*
## *Summary of Energy Efficiency Selected Offers*

| EE Contracts | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Line #** | **Offer Number** | **Counterparty** | **Description of Technology** | **LCR MW** | **Location** | **COD** | **Contract Term (Years)** |
| 1 | 408001 | Onsite Energy Corporation | EE | 1 | Western LA Basin Substations | 7/1/2018 | 4 |
| 2 | 408003 | Onsite Energy Corporation | EE | 1 | Western LA Basin Substations | 7/1/2019 | 4 |
| 3 | 408004 | Onsite Energy Corporation | EE | 1 | Western LA Basin Substations | 7/1/2020 | 4 |
| 4 | 408006 | Onsite Energy Corporation | EE | 1 | Western LA Basin Substations | 7/1/2018 | 4 |
| 5 | 408007 | Onsite Energy Corporation | EE | 1 | Western LA Basin Substations | 7/1/2019 | 4 |
| 6 | 408009 | Onsite Energy Corporation | EE | 1 | Western LA Basin Substations | 7/1/2020 | 4 |
| 7 | 408010 | Onsite Energy Corporation | EE | 1 | Johanna/ Santiago Substations | 7/1/2016 | 6 |
| 8 | 408012 | Onsite Energy Corporation | EE | 1 | Johanna/ Santiago Substations | 1/1/2017 | 5 |
| 9 | 408013 | Onsite Energy Corporation | EE | 1 | Johanna/ Santiago Substations | 7/1/2017 | 5 |
| 10 | 408015 | Onsite Energy Corporation | EE | 1 | Western LA Basin Substations | 7/1/2018 | 4 |
| 11 | 408016 | Onsite Energy Corporation | EE | 1 | Western LA Basin Substations | 7/1/2018 | 4 |
| 12 | 429001 | Sterling Analytics LLC | EE | 2 34 | Johanna/ Santiago Substations | 5/1/2016 | 6 |
| 13 | 429002 | Sterling Analytics LLC | EE | 2 36 | Johanna/ Santiago Substations | 10/1/2016 | 6 |
| 14 | 429003 | Sterling Analytics LLC | EE | 2 33 | Johanna/ Santiago Substations | 7/1/2016 | 6 |
| 15 | 429004 | Sterling Analytics LLC | EE | 0 84 | Johanna/ Santiago Substations | 2/1/2017 | 5 |
| 16 | 429005 | Sterling Analytics LLC | EE | 3 04 | Western LA Basin Substations | 1/1/2018 | 4 |
| 17 | 429006 | Sterling Analytics LLC | EE | 3 04 | Western LA Basin Substations | 4/1/2018 | 4 |
| 18 | 429007 | Sterling Analytics LLC | EE | 2 73 | Western LA Basin Substations | 7/1/2018 | 4 |
| 19 | 447100 | NRG Energy Efficiency-L LLC | EE | 5 55 | Johanna/ Santiago Substations[1] | 1/1/2017 | 5 |
| 20 | 447101 | NRG Energy Efficiency-L LLC | EE | 8 32 | Western LA Basin Substations | 1/1/2018 | 4 |
| 21 | 447102 | NRG Energy Efficiency-L LLC | EE | 13 86 | Western LA Basin Substations | 6/1/2019 | 4 |
| 22 | 447103 | NRG Energy Efficiency-L LLC | EE | 5 55 | Western LA Basin Substations | 6/1/2020 | 4 |
| 23 | 447150 | NRG Energy Efficiency-P LLC | EE | 2 31 | Johanna/ Santiago Substations | 5/1/2016 | 6 |
| 24 | 447151 | NRG Energy Efficiency-P LLC | EE | 4 63 | Johanna/ Santiago Substations | 5/1/2017 | 5 |
| 25 | 447152 | NRG Energy Efficiency-P LLC | EE | 4 32 | Western LA Basin Substations | 1/1/2018 | 4 |
| 26 | 447153<br>447154<br>447155 | NRG Energy Efficiency-P LLC | EE | 51 82 | Western LA Basin Substations | 5/1/2018 | 4 |
| | | | **Total EE:** | **124.04 MW** | | | |

[1] The Johanna and Santiago substations are in the Southwest sub-area of the Western LA Basin

The following are brief descriptions of the selected EE offers:

(1) Onsite Energy Corporation (Offers: 408001, 408003, 408004, 408006, 408007, 408009, 408010, 408012, 408013, 408015, 408016)

The Onsite Energy Corporation's ("Onsite Energy") offers consist of the following measures: [redacted] Customer types for the various measures have been identified, but specific sites have not.

(2) Sterling Analytics LLC (Offers: 429001-429007)

The Sterling Analytics LLC's ("Sterling Analytics") offers consist of [redacted] Customer types have been identified, but specific sites have not.

(3) NRG Energy Efficiency-L LLC (Offers: 447100-447103)

The NRG Energy Efficiency-L LLC's ("NRG Energy Efficiency-L") offers consist of the following measure categories that NRG Energy Efficiency-L may use: [redacted] although they have yet to be identified.

The NRG Energy Efficiency-L offer for 5.55 MW of EE (offer 447100) is an EE [redacted]. SCE included this offer in its final selection because it is a viable Preferred Resource with relatively attractive pricing that provided for energy savings in the Johanna and Santiago sub-area. The offer supports the PRP and adds value to customers as the forecasted benefits exceed the costs of the resource (*i.e.*, the resource has a positive NPV). [redacted] Finally, for many of the same reasons stated above, the IE supported the inclusion of this offer.

(4) NRG Energy Efficiency-P LLC (Offers: 447150-447155)

The NRG Energy Efficiency-P LLC's ("NRG Energy Efficiency-P") offers consist of measures utilizing [redacted]. NRG Energy

Efficiency-P proposes relying on industrial and commercial sites, although they have yet to be identified.

b) Demand Response

SCE selected seven DR contracts from one counterparty that provide a total of 75 LCR MW of savings. SCE created a DR contract for the LCR RFO that was based largely on SCE's current Aggregator Managed Portfolio ("AMP") contracts, although the LCR contracts have a 20-minute response time and credit and collateral requirements. The seller must provide delivery date security in the amount of $45/kW prior to the start of the contract, and performance assurance during the delivery period in the amount of either (1) 10 percent of the remaining capacity payments, or (2) five percent of remaining capacity payments if the contract term is greater than 10 years.

***Table VII-22***
***Summary of Demand Response Selected Offers***

| DR Contracts | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Line #** | **Offer Number** | **Counterparty** | **Description of Technology** | **LCR MW** | **Location** | **COD** | **Contract Term (Years)** |
| 1 | 447200 | NRG Distributed Generation PR LLC | DR | 5 | Johanna/ Santiago Substations | 1/1/2017 | 10 |
| 2 | 447201 | NRG Distributed Generation PR LLC | DR | 5 | Johanna/ Santiago Substations | 1/1/2017 | 10 |
| 3 | 447202 | NRG Distributed Generation PR LLC | DR | 15 | Western LA Basin Substations | 1/1/2018 | 10 |
| 4 | 447203 | NRG Distributed Generation PR LLC | DR | 15 | Western LA Basin Substations | 1/1/2018 | 10 |
| 5 | 447204 | NRG Distributed Generation PR LLC | DR | 15 | Western LA Basin Substations | 8/1/2018 | 10 |
| 6 | 447205 | NRG Distributed Generation PR LLC | DR | 15 | Western LA Basin Substations | 8/1/2018 | 10 |
| 7 | 447250 | NRG Curtailment Solutions LLC | DR | 5 | Western LA Basin Substations | 1/1/2018 | 4 |
| | | | **Total DR** | **75.00 MW** | | | |

(1) NRG Distributed Generation PR LLC (Offers: 447200-447205)

The NRG Distributed Generation PR LLC's ("NRG Distributed Generation") offers provide [redacted] NRG Distributed Generation proposes relying on industrial and commercial sites, although they have yet to be identified.

(2) NRG Curtailment Solutions LLC (Offers: 447250)

The NRG Curtailment Solutions LLC's ("NRG Curtailment Solutions") offer [redacted] NRG Curtailment Solutions proposes relying on industrial and commercial sites, although they have yet to be identified.

c) Renewable Distributed Generation

SCE selected four contracts from a single counterparty for BTM distributed renewable generation. SCE created a custom contract for this agreement that incorporates many of the EE contract provisions, but also borrows heavily from renewables contracts. [redacted]

*Table VII-23*
***Summary of Renewable Distributed Generation Selected Offers***

| Renewable DG Contracts | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Line #** | **Offer Number** | **Counterparty** | **Description of Technology** | **LCR MW** | **Location** | **COD** | **Contract Term (Years)** |
| 1 | 490002 | Solar Star California XXXV, LLC | Renewable DG BTM | 10.32 | Johanna/Santiago Substations | 10/1/2016 | 15 |
| 2 | 490003 | Solar Star California XXXVI, LLC | Renewable DG BTM | 11.22 | Western LA Basin Substations | 1/1/2018 | 15 |
| 3 | 490004 | Solar Star California XXXVII, LLC | Renewable DG BTM | 4.17 | Western LA Basin Substations | 1/1/2018 | 15 |
| 4 | 490006 | Solar Star California XXXVIII, LLC | Renewable DG BTM | 12.21 | Western LA Basin Substations | 1/1/2018 | 15 |
| | | | **Total Renewable DG** | **37.92 MW** | | | |

(1) Solar Star California XXXV, LLC, Solar Star California XXXVI, LLC, Solar Star California XXXVII, LLC, and Solar Star California XXXVIII, LLC (Offers: 490002-490004 and 4290006)

Solar Star California XXXV, LLC, Solar Star California XXXVI, LLC, Solar Star California XXXVII, LLC, and Solar Star California XXXVIII, LLC (collectively "Solar Star California") are wholly-owned subsidiaries of SunPower Corporation. Solar Star California's offers require the seller to install PV (typical installation [redacted]) at various Commercial/Industrial sites that have yet to be identified, in order to achieve energy savings. The installations will serve part of the customer's energy needs. From SCE's perspective, the power to the customer provided by the solar installation will result in customer load drop. [redacted]

d) Energy Storage

SCE selected 23 offers of ES from four counterparties for a total of 263.64 MW. A total of 100 MW was from IFOM ES.

SCE developed a separate contract form for IFOM ES and BTM ES for the LCR RFO. The IFOM ES contract takes concepts from a typical tolling contract.[83] SCE controls the charge and discharge of the ES device and payment is largely based on the availability of the unit to charge, discharge, and store electric energy. The IFOM ES contract, however, was heavily modified to capture the nuances of ES. For example, SCE incorporated guaranteed energy efficiencies on the charge and discharge cycles (*i.e.*, for every MW put into the storage device, specifying how much energy can be taken out), operating characteristics associated with ES (*e.g.*, number of cycles per month or year, number of deep discharges per day/month/year, number of MWh of discharge per year) and clarified responsibilities for charging energy versus auxiliary load for onsite energy needs. SCE also incorporated the Embedded Put Option into the IFOM ES contract to mitigate potential adverse financial impacts from 100 percent debt equivalents assessments. The IFOM ES contract includes a delivery security of $45/kW prior to the start of deliveries, and performance assurance of 10 percent of the sum of the capacity payments for 36 months during the delivery period.

For BTM ES, SCE modified the DR contract to include specific provisions associated with the construction and testing of the ES device. Fundamentally, however, the pro forma contract is largely the same as the DR contract. The seller must provide delivery date security in the amount of is $45/kW prior to the start of the contract, and performance assurance during the delivery period, in the amount of either (1) 10 percent of the remaining capacity payments, or (2) five percent of remaining capacity payments if the contract term is greater than 10 years.

A BTM ES (PLS) resource shifts energy consumption from the peak hours to the off-peak hours through the use of a storage device. The resource is non-dispatchable and is expected to run every day. Because of these characteristics and given the energy savings profile of these resources is consistent with and similar to the energy savings of EE resources, SCE modified the EE contract as the form of the agreement for BTM ES (PLS). [redacted]

[83] Fundamentally, the GFG tolling contract and IFOM ES agreement are very similar except that electric energy serves as the "fuel" instead of natural gas.

[redacted]

## *Table VII-24*
## *Summary of Energy Storage Selected Offers*

| ES Contracts | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Line #** | **Offer Number** | **Counterparty** | **Description of Technology** | **LCR MW** | **Location** | **COD** | **Contract Term (Years)** |
| 1 | 475127 | AES ES Alamitos, LLC | ES IFOM | 100 00 | 690 North Studebaker Road, Long Beach, CA 90803 | 1/1/2021 | 20 |
| | | | **Total ES IFOM** | **100 MW** | | | |
| 2 | 431049 | Ice Bear SPV #1, LLC | ES BTM PLS | 2 15 | Johanna/ Santiago Substations | 7/1/2016 | 20 |
| 3 | 431052 | Ice Bear SPV #1, LLC | ES BTM PLS | 2 15 | Johanna/ Santiago Substations | 10/120/16 | 19 8 |
| 4 | 431055 | Ice Bear SPV #1, LLC | ES BTM PLS | 2 15 | Johanna/ Santiago Substations | 1/1/2017 | 19 5 |
| 5 | 431058 | Ice Bear SPV #1, LLC | ES BTM PLS | 2 15 | Johanna/ Santiago Substations | 4/1/2017 | 19 2 |
| 6 | 431061 | Ice Bear SPV #1, LLC | ES BTM PLS | 2 15 | Johanna/ Santiago Substations | 7/1/2017 | 19 |
| 7 | 431064 | Ice Bear SPV #1, LLC | ES BTM PLS | 2 15 | Johanna/ Santiago Substations | 10/1/2017 | 18 8 |
| 8 | 431067 | Ice Bear SPV #1, LLC | ES BTM PLS | 2 15 | Johanna/ Santiago Substations | 1/1/2018 | 18 5 |
| 9 | 431070 | Ice Bear SPV #1, LLC | ES BTM PLS | 2 15 | Johanna/ Santiago Substations | 4/1/2018 | 18 2 |
| 10 | 431145 | Ice Bear SPV #1, LLC | ES BTM PLS | 1 43 | Johanna/ Santiago Substations | 1/1/2018 | 20 |
| 11 | 431148 | Ice Bear SPV #1, LLC | ES BTM PLS | 1 43 | Johanna/ Santiago Substations | 4/1/2018 | 19 8 |
| 12 | 431151 | Ice Bear SPV #1, LLC | ES BTM PLS | 1 43 | Johanna/ Santiago Substations | 7/1/2018 | 19 5 |
| 13 | 431154 | Ice Bear SPV #1, LLC | ES BTM PLS | 1 43 | Johanna/ Santiago Substations | 10/1/2018 | 19 2 |
| 14 | 431157 | Ice Bear SPV #1, LLC | ES BTM PLS | 1 43 | Johanna/ Santiago Substations | 1/1/2019 | 19 |
| 15 | 431160 | Ice Bear SPV #1, LLC | ES BTM PLS | 1 43 | Johanna/ Santiago Substations | 4/1/2019 | 18 8 |
| 16 | 431163 | Ice Bear SPV #1, LLC | ES BTM PLS | 1 43 | Johanna/ Santiago Substations | 7/1/2019 | 18 5 |
| 17 | 431166 | Ice Bear SPV #1, LLC | ES BTM PLS | 1 43 | Johanna/ Santiago Substations | 10/1/2019 | 18 2 |
| | | | **Total ES BTM PLS** | **28.64 MW** | | | |
| 18 | 467009 | Hybrid-Electric Building Technologies Irvine 1, LLC | ES BTM | 5 00 | Johanna/ Santiago Substations | 1/1/2017 | 10 5 |
| 19 | 467010 | Hybrid-Electric Building Technologies Irvine 2, LLC | ES BTM | 5 00 | Johanna/ Santiago Substations | 1/1/2017 | 10 5 |
| 20 | 467022 | Hybrid-Electric Building Technologies West Los Angeles 1, LLC | ES BTM | 25 00 | Western LA Basin Substations | 1/1/2018 | 10 |
| 21 | 467025 | Hybrid-Electric Building Technologies West Los Angeles 2, LLC | ES BTM | 15 00 | Western LA Basin Substations | 1/1/2018 | 10 |
| 22 | 402039 | Stem Energy Southern California, LLC | ES BTM | 7 00 | Johanna / Santiago Substations | 10/1/2016 | 10 |
| 23 | 402040 | Stem Energy Southern California, LLC | ES BTM | 78 00 | Western LA Basin Substations | 1/1/2018 | 8 |
| | | | **Total ES BTM** | **135.00 MW** | | | |
| | | | **Total ES** | **263.64 MW** | | | |

(1) AES ES Alamitos, LLC (Offer: 475127)

AES ES Alamitos, LLC ("AES Alamitos") offer was for a 100 MW IFOM battery storage device at their existing Alamitos site.[84] The installation will consist of large arrays of lithium ion battery racks housed in newly constructed buildings. Interconnection will be at the existing Alamitos substation. As per the contract, SCE will have complete dispatch and charging rights to the facility. Although there is uncertainty about the interconnection process and charging restrictions associated with ES, AES' ES project will interconnect at a transmission-level voltage (220 kV) substation, which should mitigate some of those concerns. AES Alamitos has a proven track record in ES and has a number of projects already in operation around the country.

(2) Ice Bear SPV#1, LLC (Offers: 431049, 431052, 431055, 431058, 431061, 431064, 431067, 431070, 431145, 431148, 431151, 431154, 431157, 431160, 431163, and 431166)

The Ice Bear SPV#1, LLC ("Ice Bear") offers will result in installations of thermal storage units (typical installations are [redacted] This may provide additional value should SCE's peak hours shift over the course of the 20 year contract.

[84] The project is co-located with AES' GFG project, but will be separately interconnected.

(3) Hybrid Electric Building Technologies Irvine 1, LLC, Hybrid Electric Building Technologies Irvine 2, LLC, Hybrid Electric Building Technologies West Los Angeles 1, LLC, and Hybrid Electric Building Technologies West Los Angeles 2, LLC (Offers: 467009, 467010, 467022, and 476025)

The Hybrid Electric Building Technologies Irvine 1, LLC, Hybrid Electric Building Technologies Irvine 2, LLC, Hybrid Electric Building Technologies West Los Angeles 1, LLC, and Hybrid Electric Building Technologies West Los Angeles 2, LLC (collectively "HEBT") offers will result in installation of battery storage (typical installations are between [redacted] HEBT is a wholly-owned subsidiary of Advanced Microgrid Solutions, Inc., which is a women-owned business, and thus will help further SCE's GO 156 goals of contracting with WMDVBE entities.

(4) Stem Energy Southern California, LLC (Offers: 402039 and 402040)

Stem Energy Southern California, LLC's ("Stem") offers will result in small battery installations (typical installation [redacted]

[redacted][85]

### 2. Gas-Fired Generation

As described in Section VI.B, SCE considered both quantitative and qualitative factors when selecting all product types, including GFG. SCE ultimately selected GFG resources that offer both site and technology diversity through contracts for a CCGT at Alamitos and a CCGT at Huntington Beach. In addition, SCE selected an RA-only offer for the Wellhead Stanton project and will provide peaking capacity at the Barre substation, which was identified as a beneficial location for GFG as described in more detail below.

SCE took two different approaches to contracting for GFG resources due to debt equivalency concerns. As detailed in IV.I above, SCE determined that the original GFG pro forma contracts that were part of the RFO launch were likely to be assessed as capital leases. In order to minimize debt equivalency, SCE incorporated the Embedded Put Option in the GFG contracts for CCGTs. However, SCE determined that the Embedded Put Option would not resolve the debt equivalency issues for CTs and thus converted the CT GFG contracts to RA-only contracts. Both the GFG with Embedded Put Option and the RA-only contracts have a delivery date security of $90/kW prior to the start of deliveries, and performance assurance of $130/kW after the start of delivery under the contract.

One consideration for the amount of SCE's selection of GFG was GFG's long development cycle. SCE was concerned that if this solicitation resulted in GFG near the lower end of the GFG-allowed authorization, it may be a challenge to add additional resources in future solicitations and have them online before the OTC compliance deadline. Based on an immediate need to procure GFG to meet the Commission's 2021 deadline and SCE's Transmission Planning personnel communicating that two GFG peakers connected at Barre Substation will provide a substantial enhancement to local area reliability, SCE included two additional peakers in its final selection.

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[85] This amount is not materially different from the pro forma calculation and was modified for ease of contracting based on the phasing of contract capacity.

***Table VII-25***
***Summary of Gas-Fired Generation Selected Offers***

| GFG Contracts | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Line #** | **Offer Number** | **Counterparty** | **Description of Technology** | **LCR MW** | **Location** | **COD** | **Contract Term (Years)** |
| 1 | 475028 | AES Alamitos Energy, LLC | GFG | 640.00 | 690 North Studebaker Road, Long Beach, CA 90803 | 6/1/2020 | 20 |
| 2 | 475029 | AES Huntington Beach Energy, LLC | GFG | 644.00 | 21730 Newland Street, Huntington Beach, CA 90803 | 5/1/2020 | 20 |
| 3 | 473237 473238 | Stanton Energy Reliability Center, LLC | GFG | 98.00 | Stanton, CA (Exact location TBD) | 7/1/2020 | 20 |
| | | | **Total GFG** | **1,382 MW** | | | |

a) <u>AES Alamitos Energy, LLC and AES Huntington Beach Energy, LLC (Offers: 475028 and 475029)</u>

SCE entered into separate GFG contracts with AES Alamitos Energy, LLC ("AES Alamitos") and AES Huntington Beach Energy, LLC ("AES Huntington Beach") for two clean, efficient CCGTs. Both projects are brownfield developments, with one CCGT being constructed at the existing Alamitos site and one CCGT being constructed at the existing Huntington Beach site. The units will both be 2x1 GE 7FA combined cycles, which offers best available operating technology parameters. Each location has a current gas-fired facility with existing interconnection and transmission infrastructure. The existing generation facilities are projected to be closed by 2020 due to OTC regulations. Both sites have an easier permitting path than a greenfield site as they can rely on the South Coast Air Quality Management District's Rule 1304 which provides access to PM-10 credits through MW-for-MW replacement, and currently have electric and fuel interconnections in place.

b) Stanton Energy Reliability Center, LLC (Offers: 473237 and 473238)

SCE entered into an RA-only contract with Stanton Energy Reliability Center, LLC ("Stanton Energy"), a subsidiary of W Power, for two GE LM6000 simple cycle combustion turbines, each with a nameplate capacity of 49.9 MW[86], for a total expected contract capacity of 98 MW. SCE will not control the dispatch rights under the contract and does not receive any energy or ancillary service benefits. However, under the RA-only agreement, the resource must bid into the CAISO market as an RA resource pursuant the CAISO tariff. The Stanton Energy peaker project will be located in Stanton, California, interconnecting to SCE's Barre substation.

As identified in the Track 1 decision, "[uncommitted energy efficiency and uncommitted CHP] are not likely to be as effective in reducing LCR needs as repowered gas-fired resources at existing OTC locations."[87] The two AES projects fit this description. In addition, the procurement of two GFG peakers at the Barre substation contributes to meeting local capacity needs stemming from the retirement of SONGS and meets LCR requirements. Barre substation is located within the Southwest sub-area of the Western LA Basin. As discussed in Section IV.G.2, the CAISO identified this area as having the highest LEFs, so resources located in this area will be most effective at relieving the critical N-1-1 contingency affecting the combined LA Basin and San Diego local capacity areas.[88] Based on the CAISO's latest LCR studies, the limiting constraint just affecting the Western LA Basin is the Serrano – Villa Park 230 kV line.[89] As identified in the CAISO's study report, generation sited at Barre had the highest effectiveness factor at meeting this Western LA Basin constraint.[90]

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[86] Although the nameplate capacity is 49.9 MW for each unit, SCE was only offered 49 MW of contract capacity for each unit.

[87] D.13-02-015 at 121 (FOF 13).

[88] CAISO, *Clarification to the ISO Board-Approved 2013-2014 Transmission Plan: Locational Effectiveness Factor Calculations in the LA Basin Area*, April 23, 2014, at 4-5.

[89] CAISO, *Final 2015 Local Capacity Technical Report*, April 30, 2014, at 75. CAISO, *Final 2019 Local Capacity Technical Report*, April 30, 2014, at 71.

[90] CAISO, *Final 2015 Local Capacity Technical Report*, April 30, 2014, at 75. CAISO, *Final 2019 Local Capacity Technical Report*, April 30, 2014, at 71.

Stanton Energy is a wholly-owned subsidiary of W Power, LLC, a California certified woman-and-minority owned business enterprise, which will help further SCE's GO 156 goals of contracting with WMDVBE entities.

## C. Interim Emissions Performance Standard

The California Legislature passed Senate Bill ("SB") 1368 on August 31, 2006, and Governor Schwarzenegger signed the bill into law on September 29, 2006. Section 2 of SB 1368 adds Public Utilities Code Section 8341(a), which provides, "No load-serving entity or local publicly owned electric utility may enter into a long-term financial commitment unless any baseload generation supplied under the long-term financial commitment complies with the greenhouse gases emission performance standard established by the commission, pursuant to subdivision (d), for a load-serving entity. . . ."[91]

In order to institute the provisions of SB 1368, the Commission instituted Rulemaking 06-04-009. That proceeding resulted in the establishment of a greenhouse gas ("GHG") emissions performance standard ("EPS") for carbon dioxide ("CO2"). In D.07-01-039, the Commission noted, "SB 1368 establishes a minimum performance requirement for any long-term financial commitment for baseload generation that will be supplying power to California ratepayers. The new law establishes that the GHG emissions rates for these facilities must be no higher than the GHG emissions rate of a CCGT powerplant."[92] The decision further explains:

> SB 1368 describes what types of generation and financial commitments will be subject to the EPS ("covered procurements"). Under SB 1368, the EPS applies to "baseload generation," but the requirement to comply with it is triggered only if there is a "long-term financial commitment" by an LSE. The statute defines baseload generation as "electricity generation from a powerplant that is designed and intended to provide electricity at an annualized plant capacity factor of at least 60%." . . . For baseload generation procured under contract, there is a long-term commitment when the LSE enters into "a new or renewed contract with a term of five or more years."[93]

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[91] Cal. Pub. Util. Code § 8341(a).

[92] D.07-01-039 at 2-3.

[93] *Id*. at 4.

All of the LCR RFO contracts entered into for the Western LA Basin are greater than or equal to five years, and therefore, qualify as long-term financial commitments. Next, the EPS applies to baseload generation, which as explained above is "electricity generation from a powerplant that is designed and intended to provide electricity at an annualized plant capacity factor of at least 60%." All, but one, of the LCR RFO contracts for the Western LA Basin have expected annualized capacity factors below the threshold baseload capacity factor of 60 percent, above which the EPS rules would apply.

The one exception is the AES facility in Huntington Beach (Offer Number 475029), which is expected to have an annualized capacity factor of [redacted] based on SCE's forecasting models. Since it has been established that the AES facility in Huntington Beach is a "covered procurement," that is not subject to any of the automatic exemptions from EPS, the emissions rate of the proposed facility must be no higher than the EPS Performance Level of 1,100 lb CO2/MWh. SCE's analysis of the future facility's heat rates and emissions profiles along with the forecasted dispatches results in an emissions rate of approximately [redacted] lb CO2/MWh, which is significantly lower than the EPS Performance Level. Thus, the AES Huntington Beach facility is EPS compliant.

An additional GFG contract, for the AES facility in Alamitos (Offer Number 475028), is expected to have a capacity factor of around [redacted] percent. Although not required per D.07-01-039, SCE also reviewed the Alamitos facility for EPS compliance purposes because it is relatively close to a baseload facility. SCE found that the emissions rate for the AES Alamitos facility is approximately [redacted] lb CO2/MWh, which is significantly lower than the EPS Performance Level.

The Stanton Energy Reliability Center (Offer Number 473237 and 473238), the only other GFG project selected, is expected to have an annualized capacity factor of [redacted] This facility will have an RA only agreement and as such, the "as-bid" heat rates were used in SCE's calculation of the capacity factor. Since the heat rate is not part of the current contracts, they have no contractual requirement on those heat rates. However, this is a peaking facility so the annualized capacity factor will be very low, and well under 60 percent.

# VIII.

## ALLOCATION OF BENEFITS AND COSTS

### A. Overview

The contracts that are the subject of this Application are necessary to meet local reliability needs for the benefit of all customers in SCE's distribution service area. Thus, the Track 4 decision instructs SCE to propose a cost allocation methodology for the resources procured through the LCR RFO:

> 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.[94]

Pursuant to this requirement, SCE recommends methods of cost allocation for each resource type for which SCE is seeking procurement approval. That said, D.14-10-051 is clear that this Application is not an appropriate venue to reconsider cost allocation of these contracts to all benefitting customers in SCE's service area.

Within this Application, SCE is seeking authorization to procure resources of varying technology types. Cost allocation will vary by type of resource. SCE recommends following existing cost allocation practices, such as CAM, where applicable. Table VIII-26 below describes how SCE proposes to treat each type of resource from a cost allocation perspective. A detailed description of how SCE plans to recover the costs of the LCR resources, ratemaking treatment, and revenue allocation is contained in Chapter IX.

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[94] D.14-03-004 (Track 4 decision) at 120.

## *Table VIII-26*
## *LCR RFO Cost Allocation Methodology*

| Description of Technology | Total Contracts | Ratemaking Treatment* | | Net Cost Determination |
|---|---|---|---|---|
| | | Balancing Account | Sub-Account | |
| **PREFERRED RESOURCES AND ES** | | | | |
| **EE** (Non-Dispatchable) | 26 Contracts (See Table VII-20) | LCR Products Balancing Account ("LCRPBA") | Public Purpose Program ("PPP") Rate Component | Allocate contract costs; no market revenues to offset contract costs |
| **DR** (Dispatchable) | 7 Contracts (See Table VII-21) | LCRPBA | Distribution Rate Component | Calculate net market revenue as the difference between CAISO market revenues less contract strike price; credit net market revenues to contract capacity cost and allocate net costs to all benefitting customers |
| **Renewable DG BTM** (Non-Dispatchable) | 4 Contracts (Refer to Table VII-22) | LCRPBA | PPP Rate Component | Allocate contract costs; no market revenues to offset contract costs |
| **ES IFOM** (Dispatchable) | 1 Contract (See Table VII-23) | LCRPBA | New System Generation ("NSG") Rate Component | Calculate net market revenue as the difference between potential energy revenue from discharge at the highest price hours of the day less the charging costs at the lowest cost hours of the day; credit net market revenues to contract capacity cost and allocate net costs to all benefitting customers |
| **ES BTM (like DR)** (Dispatchable) | 6 Contracts (See Table VII-23) | LCRPBA | Distribution Rate Component | Calculate net market revenue as the difference between CAISO market revenues less contract strike price; credit net market revenues to capacity contract cost and allocate net costs to all benefitting customers |
| **ES BTM PLS – (like EE)** (Non-Dispatchable) | 16 Contracts (See Table VII-23) | LCRPBA | PPP Rate Component | Allocate contract costs; no market revenues to offset contract costs |
| **GFG RESOURCES** | | | | |
| **GFG** (Dispatchable) | 3 Contracts (See Table VII-24 | LCRPBA | NSG Rate Component | Apply Joint Parties Proposal (JPP) to calculate market revenue; credit net market revenues to capacity contract cost and allocate net costs to all benefitting customers |

* A detailed description of how SCE plans to recover the costs of the LCR resources, ratemaking treatment, and revenue allocation is contained in Chapter IX.

While SCE has procured GFG resources to meet system reliability need, in this LCR RFO, SCE is also procuring EE, DR, and ES resources to meet local reliability need. For each resource type, SCE proposes a cost allocation that follows the "Joint Parties Proposal"[95] ("JPP"), or is in a manner consistent with the JPP. The JPP addresses how to account for expected market energy revenues associated with potential CAISO market sales in the event that the dispatch capability of the resource is not sold to a third party. The methodology used to accomplish this in the JPP is specific to GFG. As this methodology is not applicable to all of the resources procured in the LCR RFO, SCE proposes a methodology to account for market revenues for non-GFG resources that is designed to capture the intent of the JPP. SCE also proposes how the cost allocation will be calculated where market revenues are not expected.

## B. Allocation of Benefits and Costs By Technology

The sections below describe the allocation of benefits and costs for each type of resource in greater detail.

### 1. Preferred Resource Contracts

In this Application, SCE seeks approval of contracts for different categories of Preferred Resources. SCE's recommended cost allocation varies by the type of Preferred Resource and follows existing cost allocation practices where practical. The following section describes how SCE proposes to treat each of these types of resources from a cost allocation perspective.

#### a) Energy Efficiency Contracts

The costs for EE programs are currently allocated to both bundled and Direct Access/Community Choice Aggregation ("DA/CCA") customers through the PPP rate component. SCE proposes continuing this existing treatment for the EE contracts included in this Application.[96] Bundled and DA/CCA customers are equally eligible to participate in EE programs and benefit from market

[95] The Joint Parties' Proposal is defined in D.06-07-029 at 14-18 and D.07-09-044 at 7-9.

[96] As discussed in Section IX.B, SCE is proposing to provide separate accounting for costs incurred under the EE contracts so that these costs are not co-mingled with SCE's EE costs subject to balancing account recovery, however, this separate accounting does not affect how costs are allocated.

transforming programs that accelerate the availability of energy saving measures that modify participating customer loads. The EE contracts in this Application will enable third-party providers to engage in efforts to reduce participating customer loads without regard to who supplies their electricity. A continuation of current cost allocation is therefore appropriate.

Since EE does not provide for the capability to dispatch a resource, there are no CAISO market revenues associated with these contracts. In addition, EE contracts allow all distribution (bundled and DA/CCA) customers to participate in the seller's programs. As such, SCE proposes to allocate the entire cost of the contract through the PPP rate component as there will not be any market revenues to offset such costs. In addition, the contracts will not produce a resource that can be utilized to meet an RA compliance obligation. Rather, they will reduce load, and thus reduce the RA compliance obligation. Thus, the RA program will account for such resources by reducing load rather than requiring a distribution of RA counting rights to all benefitting customers.

b) Demand Response Contracts

SCE currently allocates the costs of DR programs and contracts, where eligibility is open to all customers, through the Distribution rate component charged to all customers.[97]

In the DR contracts, SCE did not restrict customer eligibility to participate based on who supplies their electricity. The LCR contracts for DR programs allow all distribution (bundled and DA/CCA) customers to participate. As such, SCE proposes that DR resources procured through the LCR RFO be recovered from all distribution customers through the Distribution rate component in the same manner as DR costs are now allocated. Doing so will ensure that: (1) methods of allocation are consistent across CPUC authorized proceedings that obtain similar resources; and (2) all benefitting customers are allocated their share of the costs necessary to meet the identified local needs.

Historically, DR programs and contracts have had either very minor or no market revenues from being dispatched within the CAISO market.[98] SCE expects that the DR contracts being submitted in this

[97] See R.13-09-011, Rebuttal Testimony of SCE at 9; May 22, 2014. For DR programs where eligibility is limited to bundled customers, SCE recovers costs in retail rates associated with bundled service.

Application will have the potential for market revenues and that such benefits should be allocated to all customers. A more detailed explanation on the handling of market revenues and the determination of net costs can be found in Section VIII.B.3 below. Any benefit associated with the right to utilize such resources to meet the RA compliance obligation will be allocated to all benefitting customers through the RA process.

c) Renewable Distributed Generation Behind the Meter Contracts

In this Application, SCE is seeking approval for contracts involving Renewable DG technologies (solar) that will provide preferred loading order generation behind the customer meter. The net effect of Renewable DG (BTM) resources will appear as a reduction in energy consumption at SCE's substations in the Western LA Basin, which will reduce local reliability requirements. For this reason, and because SCE cannot dispatch nor receive CAISO market revenues for these resources, SCE recommends that the Renewable DG (BTM) contract costs be treated in the same manner as EE contracts (see Section VIII.B.1.a above).

d) In Front of the Meter Energy Storage Contracts

IFOM ES can participate directly in CAISO markets, similar to GFG resources. They are dispatchable and can provide both energy and ancillary services. Similar to certain GFG resources procured in this LCR RFO, the IFOM ES contract SCE is submitting for approval includes an Embedded Put Option. If the option is exercised, the dispatch capability will be conveyed to SCE. If it is not, the seller will retain the dispatch rights. In the case where the option is exercised and SCE receives the dispatch rights, SCE will utilize a methodology to net the contract costs with expected market revenues which reflects the intent of the JPP to value the market revenues and costs associated with those dispatch rights. A detailed description of this methodology is contained in Section VIII.B.3 below. In the event that the option is not exercised, SCE will not receive the dispatch rights. In such a

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Continued from the previous page
98 Demand Response resources are expected to participate in CAISO markets prior to January 1, 2016.

case, SCE will not receive any market revenues associated with the contract and will allocate 100 percent of the cost of the contract to all benefitting customers. In either event, the ability to utilize the RA compliance right will be allocated to all benefitting customers through the RA program.

e) Behind the Meter Energy Storage Contracts

SCE seeks approval for a number of ES contracts that will operate behind the end-use customer meter to reduce customer load during particular periods. Some of these contracts result in a permanent load shift (PLS) from on-peak to off-peak peak periods, while other contracts allow SCE to dispatch the ES device to effectively reduce customer load based on reliability or market needs. In order to align the cost allocation of these ES contracts to existing cost allocation practices, SCE recommends that BTM ES (PLS) contracts be treated in the same manner as EE contracts and dispatchable BTM ES contracts be treated in the same manner as DR contracts. For dispatchable BTM ES treated as a DR resource, SCE will determine and credit net market revenues similar to DR contracts.

**2. Gas-Fired Generation Contracts**

The CAM has been developed and refined through a series of Commission decisions[99] to address instances where SCE has procured GFG to meet identified system needs. With this well-established history of utilizing CAM to allocate the costs of GFG to all benefitting customers, SCE proposes utilizing CAM for the GFG contracts at issue in this Application.

One of SCE's GFG selected offers was for two peaking facilities through an RA-only contract. This RA-only contract does not convey the right to dispatch the resource or receive energy revenue from the resource. As such, SCE will not receive any market revenues from the CAISO for these contracts and the entire cost of the contract will be allocated to all benefitting customers. While there will not be market revenue benefits associated with these contracts, the right to count such resources as RA against a compliance obligation will be allocated to all benefitting customers through the RA program. Thus,

[99] See D.14-03-004 at 120.

consistent with prior CAM allocations, all costs and benefits will be allocated to all benefitting customers through the NSG rate component.

Additionally, as described in Section IV.I., SCE executed contracts that contain an Embedded Put Option that can be exercised by the seller. If the option is exercised, the dispatch capability will be conveyed to SCE. In the case where the option is exercised and SCE receives the dispatch rights, SCE will utilize the JPP to value the market revenues associated with those dispatch rights. That value will then be credited to the contract costs and the net cost will be allocated to all benefitting customers. In the event that the option is not exercised, SCE will not receive the dispatch rights. In such a case, SCE will not obtain any market revenues associated with the contract and will allocate 100 percent of the cost of the contract to all benefitting customers. In either event, the ability to utilize the RA compliance right will be allocated to all benefitting customers through the RA program.

### 3. LCR RFO Proposal for Determination of Net Costs

In order to address the potential for energy revenues and energy costs associated with DR and ES resources in this application, SCE believes it appropriate to follow the policy of developing a proxy value of the energy as set forth in the JPP. However, the JPP method only specifies a method for developing a proxy value of the energy associated with GFG resources. As such, SCE proposes a methodology for the calculation of dispatch costs and revenues for non-GFG resources in a manner that is consistent with the intent of the JPP.

While certain DR and ES contracts at issue in this Application will have the opportunity to deliver energy to the CAISO and thus derive market revenues that should be credited to the costs allocated to all benefitting customers, the appropriate offset in terms of net costs to deliver energy to the CAISO cannot be based upon a natural gas-based proxy as provided for in the JPP. Because SCE's LCR DR and ES contracts specify the costs to be paid for dispatch of energy from these facilities, the contractual costs are the most appropriate to use in the calculation to determine the allocation of net costs to all benefitting customers. As with the allocation methodology for GFG resources, the proxy calculation of net market revenues will be constrained by the physical and contractual limitations associated with each resource including, but not limited to, use limitations.

Under the JPP, SCE forecasts annual energy benefits and costs by simulating the dispatch of the resource based on a forecast of expected natural gas and energy prices. These amounts are then trued-up on a proxy basis using actual CAISO market data on a quarterly basis. Forecasting the dispatch on an annual basis, however, is not practical for DR resources because SCE is limited in the number of hours that they are available. Given that forecasting the most effective hours on an annual basis will likely create a result very different than actual value, SCE will allocate the hours available for dispatch on a quarterly basis. To create this quarterly allocation, SCE will utilize the prior year CAISO market clearing prices to determine the most cost effective hours to operate DR. These hours will then establish the percentage of available hours for the DR program for allocation in the current year. Within each quarter, SCE will calculate the costs and revenues from dispatch as follows and true-up the forecasted amount. SCE will utilize the highest day-ahead hourly SP-15 Existing Zone-Generation Trading Hub[100] aggregated prices from the CAISO for the number of hours the resource is assumed available and multiply that by the quantity available for dispatch for each quarter. This will then serve as the proxy revenue from dispatch. The proxy cost will be calculated as the contract price multiplied by the assumed dispatch for the resource. The proxy revenue less the proxy costs will then be credited against the capacity costs in the Distribution rate component to create a net cost allocation that is consistent with the methodology utilized for GFG within the JPP.

This quarterly allocation of dispatch is necessary since there are significant use limitations placed on the resource in the contract. SCE cannot determine in advance which hours of the year will be the most economic to utilize use-limited DR resources. As a reasonable proxy of optimizing the dispatch of such resources, SCE is proposing to use the previous year's integrated forward market[101] prices to allocate dispatch hours across the four quarters of the calendar year. SCE will use actual market prices in each calendar quarter to ensure the optimal level of dispatch possible is credited to

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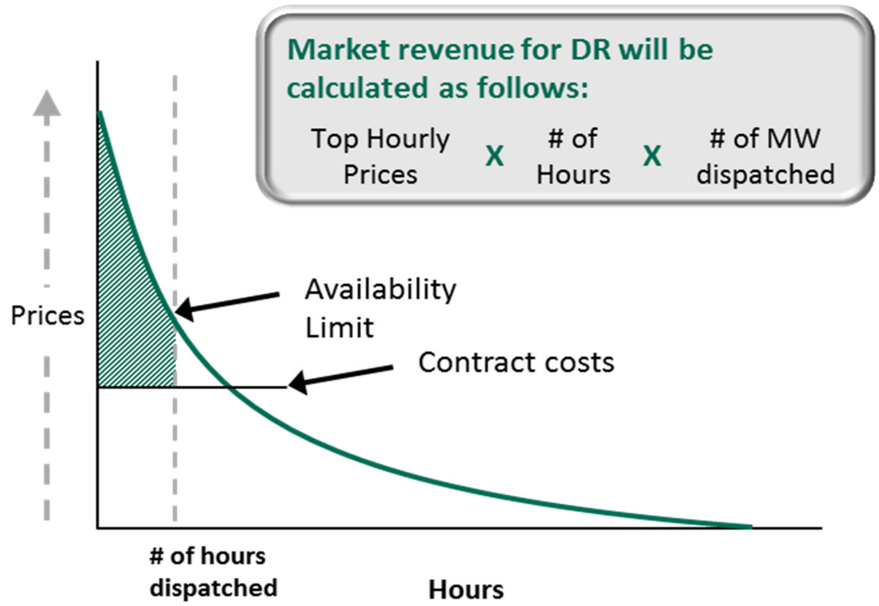
[100] See Section 27.3 of the CAISO Fifth Replacement FERC Electric Tariff and Appendix A – Master Definition Supplement to the CAISO Fifth Replacement Tariff.

[101] See Appendix A – Master Definition Supplement to the CAISO Fifth Replacement Tariff.

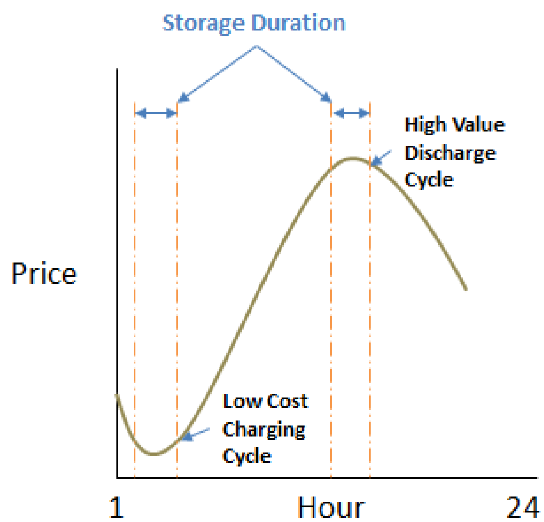
customers for the hours of dispatch assumed available for each quarter. Figure VIII-7is a graphical representation of how the market revenue for demand response will be calculated.

***Figure VIII-7***
***Demand Response Proxy Market Revenue Calculation***




As with DR, SCE will allocate the hours available for dispatch from ES on a quarterly basis. To create this quarterly allocation, SCE will utilize the prior year CAISO market clearing prices to determine the most cost effective hours to operate ES. These hours will then establish the percentage of available hours for ES to operate for allocation in the current year. Within each quarter, SCE will calculate the costs and revenues from dispatch as follows. SCE will calculate the costs for ES as the wholesale electricity price (*i.e.*, the day-ahead CAISO nodal price for the resource) multiplied by the MW necessary to charge the resource. This would be performed for each hour necessary to fully charge the resource and would utilize the lowest priced hours for the day from the CAISO for this calculation (see Figure VIII-8). Thus, the proxy cost for the resource would represent the lowest possible wholesale cost to charge the resource once each day. To calculate the proxy revenues, SCE will utilize the highest day-ahead hourly prices from the CAISO for the number of hours of discharge and multiply that by the quantity available for dispatch at the resources node. This will then serve as the proxy revenue from dispatch (see Figure VIII-8). The proxy revenue less the proxy costs will then be credited against the capacity costs in CAM to create a net cost allocation that is consistent with the methodology utilized for GFG in the JPP. Thus, the net revenues from the market for ES will be the revenue associated with simulated discharge during the highest priced hours of the day netted with the costs associated with charging during the lowest-priced hours of the day. The net market revenue will be trued up quarterly using actual market prices.

***Figure VIII-8***
***Energy Storage Proxy Market Revenue Calculation***



# IX.

## COST RECOVERY AND REVENUE ALLOCATION

As Table VIII-26 above indicates, SCE proposes to recover the costs of the resources procured in the LCR RFO through three of SCE's existing rate components: the NSG, Distribution, and PPP rate components. The NSG rate component collects the costs of contracts and SCE owned peaker generation units subject to CAM. The Distribution rate component collects the costs of distribution-related operations and maintenance, capital investments, and other programs such as the Commission-authorized demand response, California Solar Initiative, and self-generation incentive programs. The PPP rate component collects the costs of Commission-authorized programs such as, energy efficiency, low income energy efficiency, Electric Program Investment Charge ("EPIC"), and the California Alternate Rates for Energy ("CARE"). As discussed in more detail below, SCE is establishing ratemaking to ensure that customers will only pay the assessed net cost of each of these products.

### A. Cost Recovery

SCE proposes to include in its annual Energy Resource Recovery Account ("ERRA") Forecast proceeding a forecast of the costs of the resources procured through the LCR RFO to be included in rates for the following year. This is consistent with how SCE recovers its forecast of fuel and purchased power expenses. As explained in more detail below, the forecast of the costs of the LCR resources that will be included in rates will be trued-up to their assessed recorded costs through balancing accounts.

As shown in Table VIII-26 above, SCE proposes recovering the GFG and IFOM ES resource costs through the existing NSG rate component. SCE recovers all of its CAM, or new generation and certain CHP contracts the Commission has required all benefiting customers to pay for, through the NSG rate component. The calculation for determining the "benefiting costs" for these LCR resources is discussed in Chapter VIII.

Like all other DR programs that are offered to all customers, including DA customers, SCE proposes recovering the costs of DR resources procured in the LCR RFO through the Distribution rate component. Specifically, SCE will include the DR and BTM ES (like DR) resource costs through the Distribution rate component.

As authorized by the Commission, SCE recovers its EE program costs through the PPP rate component and proposes to similarly recover the costs of EE resources procured in the LCR RFO through the PPP rate component. Specifically, SCE will include the EE, Renewable DG (BTM), and the BTM ES (PLS) (like EE) resource costs in PPP rates.

SCE's rate design proposal for recovery of the LCR resources costs is discussed in the Revenue Allocation and Rate Design Section below.

## B. <u>Ratemaking</u>

SCE proposes establishing a new LCR Products Balancing Account ("LCRPBA"). Rather than recording the LCR resource costs in various existing balancing accounts, SCE proposes recording the LCR costs in a single balancing account. Included in the LCRPBA will be three sub-accounts, one for each of the three rate components that the LCR resources will be recovered through: (1) NSG; (2) Distribution; and (3) PPP. Each month, SCE will record the actual cost of these resources in their respective sub-accounts. The costs of the GFG and IFOM ES resources will be recorded in the NSG sub-account. The costs of the DR and BTM ES (like DR) resources will be recorded in the Distribution sub-account. And the costs of the EE, Renewable DG (BTM), and BTM ES (PLS) (like EE) will be recorded in the PPP sub-account.

SCE proposes to transfer the balance of the NSG sub-account component of the LCRPBA to the existing New System Generation Balancing Account ("NSGBA") each month. In the NSGBA, the cost of the New System Generation LCR-related costs and all other New System Generation costs will be balanced with the recorded New System Generation revenue each month. Any balance recorded in the NSGBA, either over- or under-collection, is included in the New System Generation rates in the following year.

Similarly, SCE proposes to transfer the balance recorded in the Distribution sub-account component of the LCRPBA to the existing Distribution sub-account of the Base Revenue Requirement Balancing Account ("BRRBA") each month. In the BRRBA, the cost of the Distribution LCR-related costs and all other distribution costs will be balanced with the recorded Distribution revenue each month. Any balance recorded in the BRRBA, either over- or under-collection, is included in the Distribution rate component in the following year.

SCE proposes to transfer the balance recorded in the PPP sub-account component of the LCRPBA to the existing Public Purpose Programs Adjustment Mechanism ("PPPAM") each month. In the PPPAM, the cost of the PPP LCR-related costs and all other PPP costs will be balanced with the recorded PPP revenue each month. Any balance recorded in the PPPAM, either over- or under-collection, is included in the PPP rate component in the following year.

## C. Review of LCR RFO Costs

The LTPP Track 1 and 4 decisions ordered the procurement of the resources considered in this Application. SCE procured these resources pursuant to its Commission-adopted Procurement Plan. As such, if the Commission finds it reasonable for SCE to enter into contracts for procurement of these resources in this docket, there is no further reasonableness review of SCE's decision to enter into these contracts. That issue will be settled. The only reasonableness issue remaining will be the reasonableness of SCE's administration of these contracts which will be considered through the annual ERRA Review proceedings.

In the annual ERRA proceedings, SCE will include for Commission audit and review all of the entries recorded in the LCRPBA to ensure that such entries are compliant with the LCR RFO decision reached in this proceeding.

## D. Revenue Allocation and Rate Design

This section describes the proposed allocation of the costs associated with the LCR RFO contracts to the individual rate groups. As discussed above, the costs of the LCR resources will be recorded in the appropriate LCRPBA sub-account, and then transferred to the NSGBA, Distribution sub-account of BRRBA, and PPPAM, respectively. The balance in these accounts will be allocated to the individual rate groups consistent with the functional revenue allocators adopted in SCE's General Rate Case ("GRC") Phase 2 proceedings. Table IX-27 illustrates the capped revenue allocators adopted in

SCE's 2012 GRC Phase 2 (D.13-03-031[102]), which will be used for revenue allocation until updated factors are adopted in its 2015 GRC Phase 2 proceeding or related proceedings involving CAM, DR, or EE allocations.

***Table IX-27***
***Functional Revenue Allocators Approved in D.13-03-031***

**Phase 2 Revenue Allocation Agreement**
**GRC Revenue Allocation**
**Summary of Revenue Allocators**
**(Illustrative)**

| | Distribution | | Generation | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Uncapped | Capped | Uncapped | Capped | APS & Interruptible Surcharge[1] | CSI/SGIP[2] | PPP[3] | NDC/PUCRF[4] | NSGC[5] |
| **Total Domestic** | 51 0% | 51 6% | 43 1% | 42 3% | 38 6% | 33 0% | 38 7% | 34 2% | 39 3% |
| GS-1 | 6 9% | 7 0% | 6 7% | 7 3% | 6 1% | 8 2% | 7 4% | 6 0% | 6 8% |
| TC-1 | 0 1% | 0 1% | 0 1% | 0 1% | 0 1% | 0 1% | 0 1% | 0 1% | 0 1% |
| GS-2 | 18 4% | 18 7% | 18 6% | 18 8% | 18 5% | 21 8% | 19 7% | 18 0% | 19 0% |
| TOU-GS-3 | 8 1% | 8 2% | 8 3% | 8 0% | 9 5% | 10 1% | 9 1% | 9 8% | 9 8% |
| **Total LSMP** | 33 6% | 34 0% | 33 7% | 34 1% | 34 2% | 40 2% | 36 4% | 33 8% | 35 6% |
| TOU-8-Sec | 6 8% | 6 5% | 8 1% | 8 2% | 9 6% | 10 2% | 9 2% | 10 3% | 9 5% |
| TOU-8-Pri | 3 8% | 3 4% | 4 6% | 4 7% | 5 8% | 6 0% | 5 4% | 6 7% | 5 4% |
| TOU-8-Sub | 1 1% | 0 9% | 4 2% | 4 2% | 5 5% | 4 3% | 3 9% | 7 2% | 4 8% |
| **Total Large Power** | 11 7% | 10 8% | 16 9% | 17 1% | 21 0% | 20 5% | 18 5% | 24 3% | 19 7% |
| **Total Ag.&Pumping** | 2 5% | 2 5% | 3 4% | 3 3% | 3 1% | 3 3% | 3 0% | 3 4% | 2 4% |
| **Total Street Lighting** | 0 1% | 0 2% | 0 5% | 0 5% | 0 4% | 0 5% | 1 1% | 0 9% | 0 4% |
| STANDBY/SEC | 0 2% | 0 2% | 0 2% | 0 2% | 0 2% | 0 3% | 0 2% | 0 3% | 0 2% |
| STANDBY/PRI | 0 6% | 0 5% | 0 7% | 0 7% | 0 8% | 0 8% | 0 7% | 0 9% | 0 7% |
| STANDBY/SUB | 0 3% | 0 3% | 1 6% | 1 7% | 1 7% | 1 5% | 1 3% | 2 3% | 1 6% |
| **Total Standby** | 1 1% | 0 9% | 2 5% | 2 6% | 2 7% | 2 6% | 2 3% | 3 4% | 2 6% |
| **Total System** | **100.0%** | **100.0%** | **100.0%** | **100.0%** | **100.0%** | **100.0%** | **100.0%** | **100.0%** | **100.0%** |

[1] APS and interruptible surcharge are allocated based on the marginal cost of generation revenue requirement for all retail sales
[2] CSI and SGIP are allocated based on each group's proportion of system revenues, excluding CARE and FERA customers, and streetlight facilities
[3] PPP revenues are allocated to rate groups on a proportion of system revenues, with DA customers imputed as bundled customers
[4] NDC and PUCRF are allocated to all retail customers on an equal ¢/kWh basis
[5] NSGC is allocated to all retail customers based on the 12-CP allocators
DCARE surcharge is allocated on an equal ¢/kWh basis, excluding the DCARE and streetlight customers
DWRBC is allocated on an equal ¢/kWh basis, excluding the DCARE customers

[102] D.13-03-031 at 58 (OP 1).

### 1. New System Generation Rate Component

GFG and IFOM ES resource costs recovered through the NSG rate component will be allocated to all retail customers based on the 12-month system coincident peak ("12-CP") allocators approved in SCE's GRC Phase 2 proceedings. NSG revenues are recovered through a cents-per-kWh energy charge.

### 2. Distribution Rate Component

DR and BTM ES resource costs recovered through the Distribution rate component will be allocated based on the allocators approved in SCE's GRC Phase 2 proceedings. The methodology adopted in SCE's 2012 GRC Phase 2 (D.13-03-031), and subsequently proposed in SCE's 2015 GRC Phase 2 (A.14-06-014[103]), allocates the DR revenue requirement to all retail customers such that 50 percent of the DR revenue requirements are allocated by each rate group's proportional share of system revenues, with generation revenues for DA customers imputed as bundled, and the remaining 50 percent of the DR revenue requirements allocated on the basis of distribution marginal cost revenues. These revenues will be collected through a dollar-per-kW demand charge for customers on demand metered rates, and through a cents-per-kWh energy charge for all other customers.

### 3. Public Purpose Programs Rate Component

EE, Renewable DG BTM and BTM ES PLS resource costs recovered through the PPP rate component will be allocated based on the allocators approved in SCE's GRC Phase 2 proceeding. The methodology adopted in D.13-03-031, and subsequently proposed in A.14-06-014, allocates the PPP revenue requirement based on each rate group's percentage share of system revenues for bundled-service and DA customers, with generation revenues for DA customers imputed as if they were bundled service customers. These revenues will be collected through a cents-per-kWh energy charge for all customers.

[103] A.14-06-014, Testimony Exhibit 3.

## X.

## RESIDUAL PROCUREMENT TO MEET WESTERN LA BASIN LCR NEEDS

SCE's proposed procurement of 1,883 MW of new, diverse projects in the Western LA Basin substantially meets the 1,900 to 2,500 MW procurement authorization the Commission provided in the LTPP Track 1 and 4 decisions. However, SCE still needs to acquire 99 MW of Preferred Resources and/or ES to meet the Commission's minimum sub-category requirement of 600 MW of Preferred Resources and ES.[104] Once SCE completes the minimum procurement required for Preferred Resources and ES, SCE's total procurement for the Western LA Basin will exceed the minimum 1,900 MW requirement for the Western LA Basin (*i.e.*, 1,883 MW of proposed procurement in this Application plus 99 MW of additional Preferred Resource and/or ES will exceed the minimum 1,900 MW requirement).

Before undertaking any major procurement initiatives to secure additional Preferred Resources, SCE will request that CAISO update its LCR studies to account for planned transmission upgrades, load forecast updates, and SCE's proposed LCR procurement to determine what residual reliability need may exist, including needed resource attributes and changes to locational effectiveness. Notwithstanding SCE's plan to seek updated CAISO LCR studies, SCE will continue to target additional LCR resources through its existing procurement mechanisms (although any such procurement will need to be demonstrated to be incremental to what would have otherwise occurred to be considered an eligible LCR resource).[105] SCE may also issue targeted solicitations for certain Preferred Resources to meet LCR needs in advance of determining if a comprehensive second LCR RFO should be pursued. All incremental LCR procurement where SCE is seeking CAM treatment conducted after SCE's initial LCR RFO will be submitted to the Commission for approval through an application process along with a specific request that it count toward SCE's minimum LCR procurement requirements.

[104] D.14-03-014 at 141-143 (OP 1). The specific minimum procurement requirement consists of 50 MW of ES (which SCE has satisfied with its proposed ES procurement in this application) and an additional 550 MW of Preferred Resources and ES.

[105] See SCE's Procurement Plan for additional discussion of ways in which SCE will continue to target additional LCR resources through its existing procurement mechanisms. Track 1 Procurement Plan of Southern California Edison Company Submitted to Energy Division Pursuant to D.13-02-015 at 48-59.