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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) to Establish Marginal Costs, Allocate Revenues, Design Rates, and Implement Additional Dynamic Pricing Rates.	A.14-06-014 (Filed June 20, 2014)

MOTION OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) AND SETTLING PARTIES FOR ADOPTION OF MEDIUM AND LARGE POWER RATE GROUP RATE DESIGN SETTLEMENT AGREEMENT

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MOTION OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) AND SETTLING PARTIES FOR ADOPTION OF MEDIUM AND LARGE POWER RATE GROUP RATE DESIGN SETTLEMENT AGREEMENT

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I.

INTRODUCTION

Pursuant to Rule 12.1 *et seq*. of the California Public Utilities Commission's (Commission's) Rules of Practice and Procedure, Southern California Edison Company (SCE), on behalf of itself and the other Settling Parties—Federal Executive Agencies (FEA); California Manufacturers & Technology Association (CMTA); California Large Energy Consumers Association (CLECA); Energy Users Forum (EUF); Solar Energy Industries Association (SEIA); Energy Producers and Users Coalition (EPUC); Association of California Water Agencies (ACWA); and Independent Energy Producers Association (IEPA) —requests that the Commission find reasonable and adopt the "Medium and Large Rate Group Rate Design Settlement Agreement" (Settlement Agreement), which is appended to this motion as Attachment A.

The Settling Parties have executed a Settlement Agreement resolving all issues that have been raised with respect to medium and large rate group rate design in this proceeding. Pursuant to the terms of the Settlement Agreement, and as soon as practicable following a Commission decision adopting the Settlement Agreement, but no earlier than January 1, 2016, SCE will adjust its rates for all of its medium and large rate group customers consistent with the terms of the Settlement Agreement.

Section II of this Motion provides the regulatory background related to this proceeding. Section III describes in general the positions advocated by the parties in this proceeding and the terms of the Settlement Agreement. Section IV demonstrates that the Settlement Agreement is reasonable in light of the whole record, consistent with law, and in the public interest, and that it should be adopted without modification. Section V discusses the procedural requests of the Settling Parties for disposing of this Motion and implementing revised rates.

II.
REGULATORY BACKGROUND

This proceeding was initiated by the filing of SCE's application on June 20, 2014, along with service of SCE's prepared direct testimony regarding marginal costs, revenue allocation and rate design (including rate design proposals for the medium and large rate group).

On September 26, 2014, the Assigned Commissioner and Assigned Administrative Law Judge issued a Scoping Memo and Ruling following a September 17, 2014 prehearing conference (PHC). On March 13, 2015, CLECA, CMTA, EUF, EPUC, SEIA, FEA, ACWA and IEP submitted prepared testimony regarding medium and large power rate design and tariff issues.

SCE provided notice to all parties of its intent to conduct a settlement conference related to all issues raised in the proceeding, and an initial settlement conference was held on Thursday, March 26, 2015. Continuing discussions related to the potential settlement of issues in this proceeding occurred among the interested parties after the settlement conference. On August 14, 2015, several parties to this proceeding filed an unopposed Motion for Approval of a Marginal Cost and Revenue Allocation Settlement Agreement (the MC/RA Settlement Agreement). This Medium and Large Rate Group Rate Design Settlement Agreement is consistent with the parameters of the MC/RA Settlement Agreement.

Each Settling Party represents customers who are directly affected by and have an interest in the outcome of the medium and large power (C&I, or commercial and industrial) rate group rate design issues in this proceeding.

III.

SUMMARY OF POSITIONS AND SETTLEMENT

The Settlement Agreement resolves all issues related to medium and large rate group rate design issues in this proceeding. The Settlement Agreement's primary provisions are summarized below and in Appendix A to the Settlement Agreement, which summarizes the positions of the Parties in their prepared testimony and how each issue is resolved by the Settlement Agreement.[1]

The C&I rate group rate design issues addressed in testimony were the following:

- The appropriate levels of customer charges, Facilities Related Demand (FRD) charges, Time Related Demand (TRD) charges, and Time-of-Use (TOU) energy charges;
- The appropriate rate design for TOU periods and Critical Peak Pricing (CPP);
- The appropriate rate design for standby rates;
- Eligibility for standby customers wishing to take service on Schedule Renewable Energy Self-Generation Bill Credit Transfer (RES-BCT); and
- The appropriate Demand Response (DR) program incentive levels.

A. Customer Charges; FRD Charges; and TRD Charges

SCE's testimony proposed that customer charges for all C&I rate groups be set based on the customer-related portion of distribution marginal costs, which includes customer service expenses and the cost of a final line transformer (FLT), service drop, and meter, and scaled to the full Equal Percentage of Marginal Cost (EPMC)-based level. The Settling Parties generally agreed with SCE's proposal. The Settlement Agreement sets customer charges at the full EPMC levels established in the MC/RA Settlement Agreement for all C&I rate groups.

SCE's testimony proposed that FRD charges for all demand-metered C&I customers be a monthly $-per-kW charge, not differentiated by TOU period or season, based on SCE's proposed design demand marginal cost and scaled to the full EPMC-based level. CLECA/CMTA submitted testimony

[1] Capitalized terms are defined in Paragraph 2 of the Settlement Agreement.

agreeing that FRD charges should be used to recover distribution capacity-related costs on a non-TOU basis. The Settlement Agreement adopts SCE's position, but sets the FRD at the cost-based level established in the MC/RA Settlement Agreement.

SCE's testimony proposed that TRD charges for all demand-metered C&I customers be set as a monthly $-per-kW charge based on the LOLE-weighted marginal cost of generation capacity, scaled to recover total allocated SCE generation revenues in combination with TOU energy charges, as described below. CLECA/CMTA submitted testimony that proposed to increase the summer on-peak charges and to decrease the summer mid-peak demand charges from current levels based on different marginal costs. CLECA/CMTA's testimony supported SCE's approach to include the summer off-peak capacity allocation in summer mid-peak demand charges. SEIA's testimony maintained that TOU energy rates in Options A and R rates are the appropriate way to recover generation-related, coincident-peak capacity costs from solar customers. EPUC's testimony recommended that TRD charges be set at EPUC's Generation Capacity Marginal Cost (GCMC) value of $199.48/kW-Year. The Settlement Agreement sets TRD charges based on a capacity cost of $102 per kW-year for C&I customers with demands greater than 500kW (*i.e.*, TOU-8 rate groups), and $95 per kW-year for C&I customers with demands less than 500kW (*i.e.*, TOU-GS rate groups), with the revenue deficiency relative to the $108 per kW-year capacity cost value adopted in the MC/RA Settlement Agreement to be recovered through summer on-peak and mid-peak energy charges.

For all TOU-C&I rate schedules, SCE proposed that the TOU energy charges be based on SCE's proposed generation marginal energy costs (MECs). CLECA/CMTA submitted testimony proposing that for TOU-8-SUB and TOU-8-PRI, charges should be set based on CLECA's adjusted MECs, which are lower and differently-shaped than SCE's, in order to reflect lower gas costs and to maintain a significant cost-based differential between the on-/mid-/off-peak energy charges that would serve as an appropriate price signal to encourage the shift of load to off-peak periods. The Settlement Agreement sets TOU energy charges based on the MECs adopted in the MC/RA Settlement Agreement.

B. TOU Periods and CPP

SCE submitted testimony proposing that the Commission should consider modifying TOU periods in the 2018 Phase 2 GRC, that default Critical Peak Pricing (CPP) be instituted in April 2017, and that the existing CPP rate structure, program design, and twelve-month customer bill protection provision be maintained. CLECA/CMTA submitted testimony maintaining that TOU periods should be revised no later than a 2015 rate design window (RDW) based on forecasted changes in net load shapes. SEIA submitted testimony proposing that C&I customers on Option A and Option R rates be allowed to participate in CPP with a Capacity Reservation Level (CRL) designated at a value less than 0, and that CPP rates be designed to be revenue-neutral to Option A and Option R rates. EUF's testimony argued that SCE should revisit the definition of TOU periods no later than in its 2018 GRC Phase 2, and that the analysis should consider the Net Demand for each hour and intra-hour periods using the California Independent System Operator's (CAISO) definition of Net Demand.

Consistent with the MC/RA Settlement Agreement, the Settlement Agreement here maintains that SCE will propose TOU period adjustments in a September 2016 RDW Application.
The Settlement Agreement also provides that default CPP migration be deferred to align with these potential TOU period redefinitions, and that the existing CPP rate structure, program design, twelve-month bill protection provision, and requirement that CPP CRL be designated as greater than or equal to zero be maintained.

C. Standby Rates

In recognition of the changing load profiles of certain types of generators who utilize SCE services for supplemental and back-up generation, SCE's testimony proposed that instead of the existing, largely manual determination of Standby customers' supplemental and back-up generation needs (billing determinants), a new algorithm based on recorded usage be used to determine the appropriate billing determinants. While generally supporting SCE's proposal, EPUC's testimony maintained that the process should be revised to include greater customer input about how the appropriate billing determinants are set. FEA agreed with EPUC. CLECA/CMTA tentatively supported

SCE's algorithm with the modifications proposed by EPUC. SEIA supported SCE's proposal to phase in the proposed new methodology over several years. IEPA's testimony opposed SCE's proposed standby algorithm as proposed to be applied to merchant generators in the TOU-8 rate class, and maintained that SCE should be directed to develop a new standby tariff for such generators that reflects their potential unique costs of service. Ultimately, the Settling Parties agreed to adopt the use of the algorithm to determine Standby customers' billing determinants, with the addition of an after-the-fact review process to ensure that the billing determinants were set with appropriate customer input regarding operating conditions for which the algorithm may not properly account, and a process to phase in the new algorithm-determined billing determinants for customers (to mitigate potentially high bill impacts).

D. Eligibility for Schedule RES-BCT

SCE submitted testimony proposing to permit Schedule RES-BCT customers with demands of less than 500 kW to again be eligible for Option A of their respective rate schedule, a rate option designed to recover all generation capacity costs through TOU energy charges, subject to the limits of SCE's share of the statewide RES-BCT cap. SEIA and ACWA supported SCE's proposal, but SEIA recommended that the rate treatment be similarly extended to RES-BCT customers with demands that exceed 500 kW (*i.e.*, TOU-8 customers). The Settlement Agreement adopts SCE's proposal to permit RES-BCT customers with demands of less than 500 kW to take standby service on Option A of their respective rate schedule[2] (with Schedule S as a rider) and adopts SEIA's proposal to allow RES-BCT customers with demands that exceed 500 kW to take standby service on a new Schedule TOU-8-Standby Option A rate schedule. RES-BCT will be closed to all new customers upon the sooner of the reaching of the statewide capacity cap of 250 MW, or SCE reaching 125 MW of eligible installed capacity.

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[2] Pursuant to the terms of the Residential and Small Commercial Settlement Agreement, RES-BCT customers with demands less than 20 kW will take service on Option C of TOU-GS-1, not Option A.

E. Demand Response (DR) Program Incentives

SCE's testimony proposed that price- and reliability-based DR program incentives be set based on the proposed marginal generation capacity cost of $85/kW-year, but that the Summer Discount Plan (SDP) incentives not be updated, and instead be maintained at existing levels until a program redesign is proposed in SCE's 2017 DR Application. For customers who participate in both the Base Interruptible Program (BIP) and the Demand Bidding Program (DBP), SCE's testimony proposed that their monthly BIP credit calculation exclude days on which the customer has participated in DBP by placing a bid. CLECA/CMTA supported SCE's proposal to exclude DBP as well as BIP event days when calculating the BIP incentive for to customers who are dual participating in both BIP and DBP, but recommended SCE use a $115.14/kW-year marginal generation capacity cost (*i.e.*, a cost based on the full avoided cost of a combustion turbine), combined with the updated 2017 LOLE study, to develop BIP credit levels. EUF proposed that the SDP incentive be reduced. The Settlement Agreement provides that the credits provided for non-firm service, including price- and reliability-based DR programs be determined based on the generation marginal capacity cost of $108/kW-year as agreed to in the MC/RA Settlement Agreement. However, the Settlement Agreement provides that BIP credit levels will be modified as follows: The level will be set at the average of the BIP incentive levels determined using the values adopted in the MC/RA Settlement Agreement and the current BIP incentive values adopted in D.13-03-031. The Settlement Agreement also adopts SCE's proposal to maintain SDP incentives at their existing levels.

IV.

REQUEST FOR ADOPTION OF THE SETTLEMENT AGREEMENT

The Settlement Agreement is submitted pursuant to Rule 12.1 *et seq*. of the Commission's Rules of Practice and Procedure. The Settlement Agreement is also consistent with Commission decisions on settlements, which express the strong public policy favoring settlement of disputes if they are fair and reasonable in light of the whole record.[3] This policy supports many worthwhile goals, including reducing the expense of litigation, conserving scarce Commission resources, and allowing parties to reduce the risk that litigation will produce unacceptable results.[4] As long as a settlement taken as a whole is reasonable in light of the record, consistent with the law, and in the public interest, it should be adopted without change.

The Settlement Agreement complies with Commission guidelines and relevant precedent for settlements. The general criteria for Commission approval of settlements are stated in Rule 12.1(d) as follows:

> The Commission will not approve stipulations or settlements, whether contested or uncontested, unless the stipulation or settlement is reasonable in light of the whole record, consistent with law, and in the public interest.[5]

The Settlement Agreement meets the criteria for a settlement pursuant to Rule 12.1(d), as discussed below.

A. <u>The Settlement Agreement is Reasonable In Light Of the Record</u>

The prepared testimony, the Settlement Agreement itself, and this motion contain the information necessary for the Commission to find the Settlement Agreement reasonable in light of the record. Prior to the settlement, parties conducted extensive discovery and served testimony on the issues related to C&I rate design. The Settling Parties request that the Commission admit the prepared testimony and related exhibits into the Commission's record of this proceeding.

The Settlement Agreement represents a reasonable compromise of the Settling Parties' positions, which are summarized in Appendices A and B to the Settlement Agreement attached hereto as Attachment A. The prepared testimony of the Settling Parties contains sufficient information for the Commission to judge the reasonableness of the Settlement.

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3 *See, e.g.,* D.88-12-083 (30 CPUC 2d 189, 221-223) and D.91-05-029 (40 CPUC 2d, 301, 326).
4 D.92-12-019, 46 CPUC 2d 538, 553.
5 *See also*, *Re San Diego Gas & Electric Company,* (D.90-08-068), 37 CPUC 2d 360.

B. The Settlement Agreement is Consistent with Law

The Settling Parties believe that the terms of the Settlement Agreement comply with all applicable statutes and prior Commission decisions, and reasonable interpretations thereof. In agreeing to the terms of the Settlement Agreement, the Settling Parties have explicitly considered the relevant statutes and Commission decisions and believe that the Commission can approve the Settlement Agreement without violating applicable statutes or prior Commission decisions.

Pages 14-16 of the Motion of Southern California Edison Company and Settling Parties for Adoption of Marginal Cost and Revenue Allocation Settlement Agreement, filed in this proceeding on August 14, 2015, explains why the Settling Parties' agreement to defer default CPP until new TOU periods have been adopted in connection with a Fall 2016 rate design window (RDW) application is reasonable and can be harmonized with prior Commission precedent. Those arguments are incorporated herein by reference.

C. The Settlement Agreement Is In the Public Interest

The Settlement Agreement is a reasonable compromise of the Settling Parties' respective positions, as summarized in Section III. The Settlement Agreement is in the public interest and in the interest of SCE's customers. It fairly resolves issues and provides more certainty to customers regarding their present and future costs, which is in the public interest.

The Settlement Agreement, if adopted by the Commission, avoids the cost of further litigation, and frees up Commission resources for other proceedings. Given that the Commission's workload is extensive, the impact on Commission resources is doubly important. The Settlement Agreement frees up the time and resources of other parties as well, so that they may focus on other proceedings and the other rate design portions of this proceeding. The prepared direct testimony contains sufficient information for the Commission to judge the reasonableness of the Settlement Agreement and for it to discharge any future regulatory obligation with respect to this matter.

Each portion of the Settlement Agreement is dependent upon the other portions of the Settlement Agreement. Changes to one portion of the Settlement Agreement would alter the balance of interests and the mutually agreed upon compromises and outcomes that are contained in the Settlement Agreement. As such, the Settling Parties request that the Settlement Agreement be adopted as a whole by the Commission, as it is reasonable in light of the whole record, consistent with law, and in the public interest.

V.

PROPOSED SCHEDULE FOR COMMENTS AND IMPLEMENTATION OF SETTLEMENT AGREEMENT

The Settling Parties seek approval of the terms of the Settlement Agreement so that SCE may implement rates as soon as practicable following the issuance of a final Commission decision approving the Settlement Agreement, but no earlier than January 1, 2016. In order to accomplish this, and given that SCE expects this Settlement Agreement to be unopposed, the Settling Parties recommend a slight deviation from the thirty-day time period provided by Rule 12.2 for comments on the Settlement Agreement (reduced from 30 days to 21 days), and the Settling Parties agree to waive reply comments. In order to accommodate questions about the Settlement Agreement in the event that there are material contested issues of fact, or questions from the Commission following the filing of comments, the Settling Parties request that a portion of one day be scheduled for a hearing (with a panel of sponsoring witnesses) in accordance with the following schedule that the assigned ALJ found reasonable in an October 5, 2015 email:

Event	**Date**
Motion filed for Adoption of the Settlement Agreement	October 28, 2015
Opening comments, if any, on the Settlement Agreement	November 18, 2015
Hearing on the Settlement Agreement	November 19, 2015

WHEREFORE, the Settling Parties respectfully request that the Assigned Commissioner, Assigned ALJ, and the Commission:

1. Approve the attached Settlement Agreement as reasonable in light of the record, consistent with law, and in the public interest; and

2. Authorize SCE to implement changes in rates and tariffs in accordance with the terms of the Settlement Agreement.

Respectfully submitted,

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And on behalf of the Settling Parties.[6]

October 29, 2015

6 In accordance with Rule 1.8(d), each Settling Party has authorized SCE's counsel to sign and file this motion on its behalf.

Attachment A
Medium and Large Power Rate Group Rate Design Settlement Agreement

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) to Establish Marginal Costs, Allocate Revenues, Design Rates, and Implement Additional Dynamic Pricing Rates.	A.14-06-014 (Filed June 20, 2014)

MEDIUM AND LARGE POWER RATE GROUP RATE DESIGN SETTLEMENT AGREEMENT

Dated: **October 28, 2015**

Medium and Large Power Rate Group Rate Design Settlement Agreement

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MEDIUM AND LARGE RATE GROUP RATE DESIGN SETTLEMENT AGREEMENT

This Medium and Large Rate Group Rate Design Settlement Agreement (Agreement or Settlement Agreement) is entered into by and among the undersigned Parties hereto, with reference to the following:

1. Parties

The Parties to this Agreement are Southern California Edison Company (SCE); Federal Executive Agencies (FEA); California Manufacturers & Technology Association (CMTA); California Large Energy Consumers Association (CLECA); Energy Users Forum (EUF); Solar Energy Industries Association (SEIA); the Energy Producers and Users Coalition (EPUC); the Association of California Water Agencies (ACWA); and the Independent Energy Producers Association (IEPA) (referred to hereinafter collectively as Settling Parties or individually as a Party).

A. SCE is an investor-owned public utility (IOU) and is subject to the jurisdiction of the California Public Utilities Commission (Commission or CPUC) with respect to providing electric service to its CPUC-jurisdictional retail customers.

B. FEA represents the consumer interests of all Federal executive agencies that take utility service from SCE, Pacific Gas and Electric Company (PG&E), and San Diego Gas and Electric Company (SDG&E).

C. CMTA is a trade association with over 25,000 large and small manufacturers in California with 1.2 million employees. Many of its members receive electrical service from SCE either as bundled service or direct access (DA) customers.

D. CLECA is an organization of large industrial electric bundled service and DA customers of SCE and PG&E. These companies are in the steel, cement, industrial gas, pipeline, minerals extraction, and beverage industries.

E. EUF is an *ad hoc* group that represents the interests of medium and large bundled service and DA customers in California, with locations in IOU and/or municipal utility service areas, taking service on rate schedules primarily for accounts with demand above 100 kW.

F. SEIA is the national trade association of the United States solar industry. Through outreach and education, SEIA and its 1,000 member companies work to make solar energy a mainstream and significant energy source by expanding markets, removing market barriers, strengthening the industry, and educating the public on the benefits of solar energy.

G. EPUC represents the end-use and customer generation interests of the following companies: Aera Energy LLC, Tesoro Refining & Marketing Company LLC, Chevron U.S.A. Inc., ExxonMobil Power and Gas Services, and California Resources Corporation.

H. ACWA is an association comprised of approximately 430 public water agencies. Collectively, ACWA members are responsible for over 90 percent of the water delivered in California.

I. IEPA is a nonprofit trade association representing the interest of developers and operators of independent energy facilities. IEPA members collectively own and operate approximately one-third of California's installed generating capacity, including renewable facilities fueled by biomass, geothermal, small hydro, solar, and wind, highly efficient cogeneration, and gas-fired merchant facilities.

2. Definitions

When used in initial capitalization in this Settlement Agreement, whether in singular or plural, the following terms shall have the meanings set forth below or, if not set forth below, then as they are defined elsewhere in this Settlement Agreement:

A. "Automatic Powershift" or "APS" means SCE's air conditioning cycling demand response program available to Commercial and Industrial (C&I) customers.

B. "Backup Service" is the electric service that is provided by SCE to a customer who has an on-site generating facility during unscheduled outages of the customer's on-site generator.

C. "Base Interruptible Program" or "BIP" means the rate schedule applicable to customers with demands of 200 kW or more who receive a credit applied to their summer and winter season

Time-Related Demand (TRD) Charges in return for the customer's agreement to reduce its demand to a specified level within either 15 or 30 minutes of notification by SCE of the need to reduce load.

D. "Base Rate" means the rate option (*e.g.*, TOU-GS-3 Option B) in a rate group (*e.g.*, TOU-GS-3) against which all other options within the rate group are designed revenue-neutral.

E. "Capacity Reservation Charge" or "CRC" means the charge assessed to Standby customers based on the customer's designated kW level of Standby Demand.

F. "Capacity Reservation Level" or "CRL" means the designated portion of a customer's demand that will not be subject to the CPP event Energy Charge and credit elements even though the customer is served on a Critical Peak Pricing (CPP) schedule. The CRL is available only to customers in the TOU-GS-3 and TOU-8 rate groups, who may designate their CRL at any percentage of their maximum demand. Consistent with Paragraph 4.G.2, the CRL must be equal to or greater than zero.

G. "C&I" means Commercial and Industrial.

H. "Cold Ironing" means the provision of electrical power for lights, heating, machinery or other needs of an ocean-going vessel at the Port of Long Beach or Port of Hueneme as replacement for the vessel's auxiliary internal combustion engines or to a truck at truck stops where the truck's internal combustion engine is turned off. For purposes of eligibility, the electric usage for Cold Ironing must be separately metered and at least 90% of the metered load must displace power generation associated with vessels or trucks that would otherwise be provided by internal combustion generation on the vessel or the truck (or as additionally designated in SCE's tariffs).

I. "Commission" or "CPUC" means the California Public Utilities Commission.

J. "Critical Peak Pricing" or "CPP" means a dynamic rate that allows a short-term, CPP-event Energy Charge of a predetermined level during high load or other high-cost system conditions. Typically, the time and duration of the CPP Energy Charge are predetermined, but the CPP event days are not predetermined. Participating customers receive a credit reflected in summer TRD Charges or Energy Charges, where applicable, on all days when CPP events are not called.

K. "CPP-Lite" means a version of the CPP tariff where the CPP Energy Charges are established at one-half of the cost-based level, and the associated credit level applied to the TRD or Energy Charge is correspondingly established at one-half of the level of the cost-based CPP schedule.

CPP-Lite is available only to non-residential customers served on TOU rate schedules with demands of less than 200 kilowatts (kW).

L. “Customer Charges” mean the fixed dollar per month charges applied to customers in the C&I rate groups that are designed to recover the fixed customer costs of connection to SCE’s system.[1]

M. “Default Rate” means the rate schedule on which the customer is automatically placed when starting service unless the customer requests otherwise.

N. “Demand Charges” mean those charges that are comprised of Facilities Related Demand (“FRD”) Charges and TRD Charges, which are based on the customer’s maximum kW demand during the specified billing periods. Demand Charges recover a portion of SCE’s delivery and generation costs, where such charges apply to a specific rate schedule.

O. “Energy Charges” mean the dollar-per-kilowatt-hour (kWh) charges that recover (1) the portion of SCE’s generation services revenues not recovered in Time-Related Demand Charges; (2) the remaining portion of SCE’s delivery services revenues where there are no Facilities-Related Demand Charges; and (3) other delivery services revenues for public purpose programs (including Energy Efficiency and California Alternate Rates For Energy (“CARE”), New System Generation Service (NSGS), Nuclear Decommissioning, California Department of Water Resources (DWR) bonds, and CPUC reimbursement fees. Energy Charges are designed to provide a price signal consistent with marginal cost differentials in time of use (“TOU”) energy rates, where TOU energy rates apply to a specific schedule.

P. “EPMC” means equal percent of marginal cost. Because marginal cost revenues do not equal the utility’s revenue requirement, in general, the utility revenue requirement is allocated to different rate groups in proportion to each rate group’s percentage share of marginal cost revenue responsibility by function (*i.e.*, separately for generation costs, and combined distribution and customer costs).

Q. “Existing Standby Customers” means Standby service accounts with at least 14 months of interval data available as of the effective date of the decision approving this Settlement Agreement.

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[1] The term “customer” as used in this Agreement generally refers to a service account when used in the context of eligibility and the rates for a particular tariff or rate schedule.

R. "Facilities-Related Demand Charges" or "FRD Charges" mean the charges applied to customers' monthly peak demands, not differentiated by TOU or by season, that are designed to recover certain transmission and distribution costs that are defined to be unrelated to generation system peak or coincident peak usage. FRD charges for Standby customers are called "Excess FRD Charges."

S. "Functional SAPC Allocation" means allocation of SCE's revenue requirement to each of SCE's rate groups based on the system average percentage change (SAPC) for the particular function, *e.g.*, generation, or distribution and customer costs.

T. "Gross Nameplate Capacity" means the total gross generating capacity of a generator or a generating facility (as defined in SCE's Rule 21) as designated by the manufacturer(s) of the generator or generating facility.

U. "Large Power Rate Group" means the following SCE rate groups: (1) the TOU-8 rate groups, comprised of customers with demands that are more than 500 kW and are differentiated by service voltage as follows: TOU-8-Subtransmission (TOU-8-Sub), which is for service above 50 kV; TOU-8-Primary (TOU-8-Pri), which is for service from 2 kV to 50 kV; and TOU-8-Secondary (TOU-8-Sec), which is for service below 2 kV; and (2) the three TOU-8-Standby (TOU-8-S) rate groups, with service voltage differentiation being the same as the three TOU-8 rate groups.

V. "MC/RA Settlement Agreement" means the Marginal Cost and Revenue Allocation Settlement Agreement filed in this proceeding on August 14, 2015.

W. "Medium Power Rate Group" means the TOU-GS-2 rate group, which is comprised of C&I customers with demands of more than 20 kW but less than 200 kW, and the TOU-GS-3 rate group, which is comprised of C&I customers with demands between 200 kW and 500 kW.

X. "New Standby Customers" means standby service accounts with cut-over-to-operations dates on or after the effective date of the decision approving this Settlement, and before the implementation of a final decision in SCE's 2018 GRC Phase 2 proceeding.

Y. "OAT" means the customer's otherwise applicable tariff.

Z. "Permanent Load Shift" means technologies that are installed to allow customers to shift load that would otherwise occur during peak periods to off-peak periods on a permanent basis.

AA. "Renewable Distributed Generation Technologies" means renewable generation technology as defined in the Statewide California Solar initiative, the Self-Generation Incentive Program, or their successors.

BB. "Renewable Energy Self-Generation Bill Credit Transfer" (RES-BCT) means the requirement that the IOUs offer a tariff that allows local governments and campuses to generate electricity from an eligible renewable generating facility for their own use and to export energy not consumed at the time of generation to SCE's grid. All generation exported to SCE's grid is converted into bill credits and applied as dollars to benefiting accounts as designated by the local government or campus. RES-BCT service does not represent a form of Net Energy Metering (NEM) service and thus customers taking RES-BCT service are not exempt from standby charges.

CC. "Rider" means an addendum to an OAT. Customers may elect to participate on a rider or be placed on a rider due to specific operating conditions.

DD. "RTP" means Real Time Pricing.

EE. "SCE RECC" means the method used by SCE to determine marginal customer costs for each rate group in Exhibit SCE-02, dated June 20, 2014. "RECC" stands for "Real Economic Carrying Charge," which is the percentage of a utility investment which corresponds to the first year of a stream of numbers where the net present value of revenue requirements of a utility investment is adjusted to rise at the rate of inflation over the life of the investment. It also represents the value of deferring a utility investment by a year.

FF. "Secondary Standby Implementation Date" is the date on which the new Billing Determinants, as calculated by the Standby Algorithm, are either phased-in for Transition Standby Customers or implemented for New Standby Customers. As described in Appendix C, customers will receive a bill impact analysis using Algorithm-calculated Billing Determinants after 14 months of interval data is available, and will have those Billing Determinants phased-in approximately three months after receipt of the bill impact analysis.

GG. "Standby Algorithm," or "Algorithm" is the algorithm proposed by SCE in Exhibit SCE-08, as modified by the Settling Parties in this Settlement Agreement that is used to determine the Supplemental Contract Capacity and Standby Demand levels for customers receiving standby service. For the purposes of this Settlement Agreement, references to the Standby Algorithm also include, where applicable, the Confirmation Review and Phase-In processes, as those terms are defined and discussed in Appendix C hereto. A description of the Standby Algorithm that is based on excerpts from SCE-08 is contained in Appendix D.

HH. "Standby Billing Determinants" or "Billing Determinants" means a Standby service customer's Supplemental Contract Capacity and Standby Demand levels.

II. "Standby Demand" or "Reserve Capacity" is the kW level of service designated by a Standby service customer that SCE will provide during periods when that customer's generating facility is out of service.

JJ. "Standby Implementation Date" is the date on which the new Billing Determinants, as calculated by the Standby Algorithm, are phased-in for Existing Standby Customers. This date is estimated to be approximately three months after the date rates implementing this Settlement Agreement take effect.

KK. "Supplemental Contract Capacity" represents the maximum level of kW associated with Supplemental Service.

LL. "Supplemental Service" is the service provided by SCE to a Standby Service customer for the portion of the customer's load that is regularly provided by SCE as if the customer were a full requirements-service customer.

MM. "Time-Related Demand Charges" or "TRD Charges" are generation-related, marginal-cost-based, capacity-related charges assigned to TOU periods based on loss-of-load probabilities during the TOU periods. Scaled TOU marginal energy costs along with the TRD Charges are designed to collect the allocated revenue requirement for SCE's base generation and fuel and purchased power costs.

NN. "TOU" means time-of-use. These are the time periods established for the provision of electric service in which demand charges or Energy Charges may vary in relation to the cost of service.

OO. "Transmission Owners Tariff Charge Adjustments" or "TOTCA" represents transmission-related revenue balancing accounts.

PP. "Transition Standby Customers" means standby service accounts that were cut-over-to-operations prior to the effective date of the decision approving this Settlement Agreement who lack at least 14 months of available recorded metered demand data on that date.

3. **Recitals**

A. In Phase 2 of SCE's 2015 General Rate Case (GRC), the Commission allocates SCE's authorized revenue requirement among rate groups and authorizes rate design changes for rate schedules in each rate group.

B. On June 20, 2014, SCE served its initial prepared testimony regarding marginal costs, revenue allocation and rate design in Application 14-06-014. On January 23, 2015, SCE served errata to its direct testimony and supplemental testimony regarding SCE's Standby proposal.[2]

C. ORA served its initial testimony on February 13, 2015. Intervenors, including the Settling Parties to this Agreement, served their initial prepared testimony on March 13, 2015.

D. The following intervenors submitted prepared testimony regarding C&I customer rate design for the Medium and Large Power Rate Groups: FEA, EUF, CMTA/CLECA, SEIA, IEPA, EPUC and ACWA.

E. SCE provided notice to all parties of its intent to conduct a settlement conference related to all issues raised in the proceeding, and an initial settlement conference was held on March 26, 2015.

F. Continuing settlement discussions occurred among the parties after March 26, 2015.

G. Appendix A to this Agreement provides a comparison of the Settling Parties' positions, where applicable, related to Medium and Large Power Rate Group rate design issues that have been resolved by this Agreement. In the event of a conflict between the terms of this Agreement and Appendix A, the terms of this Agreement shall control. Appendix B provides illustrative Medium and Large Power rates resulting from this Settlement Agreement. Appendix C provides the Procedures for Modification and Phase-In of Standby Billing Determinants; in the event of a conflict between the terms of this Agreement and Appendix C, the terms of Appendix C shall control. Appendix D contains relevant excerpts from Exhibit SCE-08 describing the Standby Algorithm that were not explicitly modified in this Agreement; in the event of a conflict between the terms of Appendices C and D, the terms of Appendix C shall control.

H. The Settling Parties have evaluated the impacts of the various proposals in this proceeding and desire to resolve all issues related to rate design for the Medium and Large Power Rate Groups beginning with the implementation of a CPUC decision approving this Agreement, and, in

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[2] Exhibits SCE-07 and SCE-08, respectively.

consideration of the mutual obligations, covenants and conditions contained herein, have reached agreement as indicated in Paragraphs 4 and thereafter of this Agreement.

4. Agreement

Nothing in this Agreement shall be deemed to constitute an admission by any Settling Party that its position on any issue lacks merit, or a claim by a Settling Party that its position has greater or lesser merit than the position taken by any other Settling Party. This Agreement is subject to the express limitation on precedent as provided in Commission Rule 12.5 and as described in Paragraph 11. Unless specifically stated otherwise herein, this Agreement and its terms are intended to remain in effect until a decision is implemented in Phase 2 of SCE's next GRC.

A. Illustrative Rates

The Settling Parties agree that the results of the rate design process illustrated by the rate schedules in Appendix B to this Agreement are reasonable. These rates are based on the Medium Power and Large Power Rate Groups' share of the estimated consolidated revenue requirement of $12,936 million described in more detail in Paragraph 4.B.1. of the MC/RA Settlement Agreement. These illustrative rates shall be adjusted consistent with the terms of this Agreement and the CPUC's decision in this proceeding related to the MC/RA Settlement Agreement to reflect SCE's actual total system revenue requirement when this Agreement is implemented.

B. Common Rate Design Principles

1) Rate Structure Elements

Consistent with SCE's Application, rate structures for the Medium and Large Power Rate Groups will generally consist of Customer Charges, Time-of-Use and/or seasonal Energy Charges, TRD Charges, and FRD Charges. Default CPP rate schedules will continue to apply to the TOU-GS-3 and TOU-8 rate groups. Optional CPP rate schedules will continue to be available to customers served in the TOU-GS-2 rate group. Optional RTP rate schedules will also continue to be available.

2) Customer Charges

Customer Charges shall be derived based on SCE's as-proposed RECC customer marginal cost method. Customer Charges shall be set at the full EPMC level for all customers in the Medium and Large Power Rate Groups. Estimated monthly Customer Charges are listed in Table C&I-1, below:

Table C&I-1
Estimated Monthly Customer Charges[3]

Rate Group	Customer Charge
Flat GS-2	$202.25
TOU-GS-2	$202.00
TOU-GS-3	$409.00
TOU-8-SEC	$582.25
TOU-8-PRI	$278.00
TOU-8-SUB	$1897.50

When this Agreement is first implemented in 2016, these estimated Customer Charges shall be adjusted, as necessary, consistent with the then-current revenues allocated to each rate group in accordance with the MC/RA Settlement Agreement.[4] Thereafter, these Customer Charges shall be adjusted on a Functional SAPC basis.

3) Energy Charges

Proposed Energy Charges based on SCE's 2016 estimated consolidated revenue requirement are set forth in Appendix B.[5] When this Agreement is first implemented in 2016, these estimated Energy Charges shall be adjusted, as necessary, consistent with the then-current revenues allocated to each rate group in accordance with the MC/RA Settlement Agreement.[6] Thereafter, these estimated Energy Charges shall be adjusted consistent with Paragraph 4.B.7 of the MC/RA Settlement Agreement when SCE's authorized revenue requirements change.

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[3] Customer Charges for the Standby TOU-8-Sec, -Pri, and Sub are equal to the Customer Charges for the corresponding TOU-8-Sec, -Pri, and –Sub rate groups.

[4] *See* Paragraph 4.B.6 of the MC/RA Settlement Agreement.

[5] The estimated consolidated revenue requirement, as defined in Paragraph 4.B.1 of the MC/RA Settlement Agreement, is $12,936 million.

[6] *See* Paragraph 4.B.6 of the MC/RA Settlement Agreement.

a) **Non-Generation-Related Energy Charges**

Energy Charges that are designed to recover revenues associated with certain transmission (TOTCA), distribution, public purpose programs, new system generation service, nuclear decommissioning, the California Department of Water Resources bonds, and the CPUC reimbursement fee shall be established on the basis of the specific functional authorized revenue requirements and the terms specified in the MC/RA Settlement Agreement.

b) **Generation-Related Energy Charges**

Except where otherwise specified in this Agreement for RTP, Electric Vehicle ("EV") and super off peak ("SOP") rates, generation-related Energy Charges shall be established based on the TOU marginal energy costs set forth in the MC/RA Settlement Agreement.

4) **Demand Charges**

Demand Charges shall consist of TRD Charges and FRD Charges. TRD Charges may be differentiated by summer and winter seasons and by TOU periods. FRD Charges are not differentiated by season or TOU periods.

a) **TRD Charges**

Consistent with the values for marginal generation capacity cost, marginal energy cost, and the estimated adjusted consolidated revenue requirement set forth in the MC/RA Settlement Agreement, the estimated TRD Charges that are established to recover the agreed upon capacity portion of the allocated generation revenues for the TOU-GS-2, TOU-GS-3, TOU-8, and the TOU-8-S rate groups shall be as set forth in Tables C&I-2 and C&I-3, below.

To mitigate bill impacts, TRD Charges for the Medium and Large Power Rate Groups with demands of 500 kW or less shall be established with a marginal generation capacity cost of $95 per kW-year, instead of the $108 per kW-year cost that underlies the MC/RA Settlement Agreement. For C&I rate groups with demands greater than 500 kW, TRD charges shall be established with a marginal generation capacity cost of $102 per kW-year, instead of the $108 per kW-year cost that underlies the MC/RA Settlement Agreement. To maintain consistent TOU generation cost recovery, the generation revenue deficiency relative to the $108 per kW-year value that is reflected in the MC/RA Settlement Agreement will be recovered, where applicable, in the summer season on- and mid-peak Energy Charges, maintaining the same percentage recovery of generation revenues by TOU periods.

Table C&I-2
Estimated Time-Related Demand Charges

	TOU-GS-2	TOU-GS-3	TOU-8-SEC	TOU-8-PRI	TOU-8-SUB
Summer On-Peak $/kW	21.38	21.14	23.18	23.56	24.37
Summer Mid-Peak $/kW	4.19	4.17	4.46	4.45	4.38

Table C&I-3
Estimated Backup and Supplemental Time-Related Demand Charges for Standby

	TOU-8-S-SEC	TOU-8-S-PRI	TOU-8-S-SUB
Backup Summer On-Peak $/kW	15.60	15.86	11.50
Backup Summer Mid-Peak $/kW	2.65	2.89	1.65
Supplemental Summer On-Peak $/kW	23.18	23.56	24.37
Supplemental Summer Mid-Peak $/kW	4.46	4.45	4.38

When this Agreement is first implemented, the above estimated TRD Charges shall be adjusted, as necessary, consistent with the then-current revenues allocated to each rate group in accordance with the MC/RA Settlement Agreement.[7] Thereafter, these estimated TRD Charges shall be adjusted consistent with Paragraph 4.B.7 of the MC/RA Settlement Agreement when SCE's authorized generation revenues change.

[7] *See* Paragraph 4.B.6 of the MC/RA Settlement Agreement.

b) **<u>FRD Charges</u>**

FRD Charges (and the CRC and Excess FRD Charges for Standby) that are established to recover certain allocated delivery revenues, including SCE's base transmission revenues as adopted in FERC proceedings, for the TOU-GS-2, TOU-GS-3, and TOU-8 rate groups, shall be consistent with the marginal costs reflected in the MC/RA Settlement Agreement, as indicated in Tables C&I-4 and C&I-5, below:

Table C&I-4
Estimated Facilities-Related Demand Charges

	TOU-GS-2	TOU-GS-3	TOU-8-SEC	TOU-8-PRI	TOU-8-SUB	TOU-8-220 kV
FRD Charge, $/kW	13.43	15.99	16.34	16.32	6.75	3.63

Table C&I-5
Estimated CRC and Excess Facilities-Related Demand Charges for Standby

	TOU-8-S-SEC	TOU-8-S-PRI	TOU-8-S-SUB	TOU-8-S-220kV
Facilities Related Demand (Excess FRD) $/kW	15.84	16.10	6.69	3.57
Capacity Reservation (CRC) $/kW	8.45	8.18	1.01	0.56

5) **<u>Voltage Discounts</u>**

Customers served at higher voltage delivery levels than the design voltage level for their rate group will receive a voltage discount reflecting their relatively lower cost of service.
SCE will establish the discount levels based on the difference in marginal costs of service between the design or predominant voltage level for a given rate group and the higher voltage service options. Voltage discounts shall apply to rate schedules in the TOU-GS-2, TOU-GS-3, TOU-8, and TOU-8-S rate groups, as indicated in Appendix B. The TOU-8 and Standby rate groups have voltage-differentiated rates, as reflected in the applicable tariffs, with the exception of service provided at the 220 kV level or higher.

6) **<u>Power Factor Adjustments</u>**

The method for determining power factor adjustment rates will be revised to more closely reflect SCE's cost of correcting poor power factor conditions, as indicated in Exhibit SCE-

04. Power factor adjustments paid by certain customers shall be as proposed by SCE in its testimony, which is $0.47 $/kVAR for service at or above 50 kV and $0.55/kVAR for service at less than 50 kV.[8]

7) Demand Response and Dynamic Pricing Credits (APS, CPP, CPP-Lite, and BIP)

Rate structures and rate designs associated with SCE's demand response and dynamic pricing programs, *e.g.*, BIP, APS, and CPP, shall be based on the Avoided Capacity Valuation Methodology as described in Exhibit SCE-02.

The credits that are provided for non-firm service, including price-based and reliability-based demand response programs, shall be based on the net marginal generation capacity cost that is reflected in the MC/RA Settlement Agreement, which is a generation marginal capacity cost of $108 per kW-year, with the following adjustments:

i. To more closely align the basis for BIP program incentives with the agreed upon generation marginal capacity cost, the Settling Parties agree to average the BIP program credits, whose inputs are determined by the MC/RA Settlement Agreement and by this Settlement Agreement, with the current BIP incentive values adopted in D.13-03-031.

ii. As proposed by SCE in Exhibit SCE-04, APS program incentives will be retained at the current incentive levels until such time at the Commission reviews and approves a program redesign (likely in the next Demand Response Application cycle).

iii. CPP program credit and charge levels will be retained at the current values as proposed in Exhibit SCE-04.

Illustrative proposed rates are listed in Appendix B.

8) TOU and Seasonal Periods

SCE's existing on-, mid-, off-, and SOP TOU periods and SCE's summer season and winter season definitions for C&I customers shall not be modified from their current TOU periods. Consistent with Paragraph 4.C. of the MC/RA Settlement Agreement, SCE shall examine changing TOU periods in a September 2016 Rate Design Window application.

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[8] Exhibit SCE-04, p. 16.

9) Implementing Future Revenue Changes in Rates

As described in the MC/RA Settlement Agreement,[9] when SCE's authorized revenues change in the future, SCE will first adjust rate levels for the default rate schedules (without CPP elements), *e.g.*, Schedules TOU-GS-2, TOU-GS-3, and Schedule TOU-8-Sec-B, using a Functional SAPC adjustment. SCE will then rebalance optional rate levels to ensure revenue neutrality between the default rate schedule and the optional rate schedules.

For example, generation revenue changes resulting from SCE's ERRA proceedings shall be allocated on a Functional SAPC basis, *i.e.*, the revised SCE generation revenue requirement will be allocated by applying a generation-level SAPC scalar to the relevant generation-related charges, based on the difference between present rate revenues and proposed rate revenues for the default rate schedules. The optional rate schedules will then be adjusted to ensure revenue neutrality on a functional basis.

C. TOU-GS-2 Rate Group

Illustrative proposed rates for the TOU-GS-2 rate schedules are listed in Appendix B.

1) Schedule GS-2

The "flat" Schedule GS-2 remains open to a very small number of customers who lack interval meters, particularly those on Catalina Island. This rate schedule shall include a monthly Customer Charge, established as provided in Table C&I-1; a summer-season TRD Charge, established as provided in Table C&I-2; an FRD Charge, established as provided in Table C&I-4; and summer and winter Energy Charges. Upon initial implementation of this Agreement, the Customer Charge in Schedule GS-2 shall reflect its then-current value as may be revised by a Functional SAPC adjustment.

SCE shall continue to retain the bill limiter provision of Schedule GS-2.

2) Default Schedule TOU-GS-2, Option B

Since January 1, 2014, the default rate structure for the TOU-GS-2 rate group has been Schedule TOU-GS-2 Option B, which consists of a monthly Customer Charge, established

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[9] *See* Paragraph 4.B.7 of the MC/RA Settlement Agreement.

as provided in Paragraph 4.B,2, above, summer on- and mid-peak TRD Charges, an FRD Charge, and summer and winter seasonal TOU Energy Charges, as indicated in Appendix B. The TRD Charges will be based on a marginal generation capacity cost of $95 per kW-year, with the revenue shortfall relative to the $108 per kW-year value that is reflected in the MC/RA Settlement Agreement recovered through the summer on- and mid-peak Energy Charges.

3) Optional TOU-GS-2 Rate Schedules

Eligible customers may elect to take service on Schedules TOU-GS-2 Option A, TOU-GS-2-CPP, TOU-GS-2-RTP, or TOU-GS-2-R (Option R) in lieu of service on TOU-GS-2 Option B, which is the default rate schedule.

Schedule TOU-GS-2 Option A shall consist of a monthly Customer Charge, established as provided in Paragraph 4.B.2, above, an FRD Charge, and summer and winter seasonal TOU Energy Charges.

Other optional TOU-GS-2 rate schedules will include Schedule TOU-GS-2-CPP,[10] which shall consist of a monthly Customer Charge, TOU summer and winter Energy Charges, summer on- and mid-peak TRD Charges, an FRD Charge, with an event period Energy Charge of $0.687 cents per kWh and a summer on-peak demand credit of $5.38 per kW; and TOU-GS-2-RTP.

D. TOU-GS-3 Rate Group

Illustrative proposed rates for the TOU-GS-3 schedules are listed in Appendix B.

1) Default TOU-GS-3 Structure

The default rate structure for customers with peak demands of 200 kW to 500 kW shall be Schedule TOU-GS-3-CPP, which consists of a monthly Customer Charge, established as provided in Table C&I-1; summer on- and mid-peak TRD Charges, established as provided in Table C&I-2; an FRD Charge, established as provided in Table C&I-4; summer and

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[10] TOU-GS-2 customers will also continue to have the option of taking service on CPP-Lite, which contains CPP charges and credits at half the full cost-based level. CPP-Lite offers a hedging mechanism to customers who do not elect full cost-based CPP.

winter TOU Energy Charges; and includes CPP event charges of $1.37 per kWh and a summer on-peak demand charge credit of $11.44 per kW.

2) **Schedule TOU-GS-3, Option B**

Schedule TOU-GS-3 Option B shall be the Base Rate for customers in the Medium Power Rate Groups (who opt out of the default TOU-GS-3 rate schedule with CPP components or who are ineligible for CPP rates) and includes a Customer Charge, TOU Energy Charges, a summer on- and mid-peak TRD Charge, and an FRD Charge, designed as specified in this Agreement for the three TOU-GS-3 rate groups and as indicated in the illustrative rates in Appendix B.

3) **Optional TOU-GS-3 Rate Schedules**

Eligible customers may elect to take service on Schedule TOU-GS-3, Options A or B; TOU-GS-3-R (Option R); or other applicable tariffs. Schedule TOU-GS-3-SOP shall retain its existing rate and TOU period structure. SCE shall update Schedule TOU-GS-3-SOP Energy Charges and Demand Charges on a revenue neutral basis with Schedule TOU-GS-3-B.

4) **Schedule TOU-EV-4**

Schedule TOU-EV-4 provides discounted off-peak Energy Charges, subject to a floor price that is defined by D.07-11-052 as the sum of SCE's marginal generation and distribution costs plus non-bypassable charges, for commercial EV battery charging operations. On-peak Energy Charges will be set to recover generation energy- and capacity-related costs, and the revenue deficiency recovery resulting from the off-peak TOU period discount. The current TOU periods shall be retained subject to revision consistent with Paragraph 4.C of the MC/RA Settlement Agreement.

E. **TOU-8 Rate Group**

Illustrative proposed rates for the TOU-8 rate schedules are listed in Appendix B.

1) **Default TOU-8 Rate Structures**

The default rate structure for customers with peak demands of more than 500 kW shall be Schedule TOU-8-CPP, which consists of a monthly Customer Charge, established as provided in Table C&I-1; summer on- and mid-peak TRD Charges, established as provided in Table C&I-2; an FRD Charge, established as provided in Table C&I-4; summer and winter TOU Energy Charges, and includes CPP event charges of $1.37 per kWh and a summer on-peak demand charge credit which varies by service voltage level, as indicated in the illustrative rates in Appendix B.

2) **Schedule TOU-8, Option A**

Schedule TOU-8, Option A, shall continue to be offered as an alternative rate for customers who employ Cold Ironing or Permanent Load Shift (PLS) technologies (and to non-Cold Ironing and non-PLS customers who continued to elect to take service on the Special Solar Allowance[11] that was in effect before it closed to new customers consistent with D.14-12-048). To be eligible for the Cold Ironing option, the customer must comply with any and all applicable requirements of Rule 18.

Rates for Schedule TOU-8, Option A, shall be structured to recover all generation-related capacity costs through volumetric Energy Charges on a cents per kWh basis. No changes will be made to the current structure for recovering delivery-related demand charges.

3) **Schedule TOU-8, Option B**

Schedule TOU-8 Option B shall be the Base Rate for customers in the Large Power Rate Groups who opt out of the default TOU-8 rate schedule with CPP components or who are ineligible for CPP rates. It shall include a Customer Charge, TOU Energy Charges, a summer on- and mid-peak TRD Charge, and an FRD Charge, designed as specified in this Agreement for the three TOU-8 rate groups, and as indicated in the illustrative rates in Appendix B.

4) **Schedule TOU-8-RTP (Real Time Pricing)**

The Energy Charges for Schedule TOU-8-RTP shall be modified as described in Exhibit SCE-04, consistent with the following: Schedule TOU-8-RTP generation capacity charges, established on an hourly cents per kWh basis, shall reflect a generation marginal capacity

[11] Special Solar Allowance means the 50 MW of Schedule TOU-8, Option A available for Schedule TOU-8 customers after the 150 MW cap on Rate R had been reached pursuant to D.13-03-031. The Special Solar Allowance was open to customers who install solar generation and who would otherwise qualify for Option R of Schedule TOU-8.

cost of $108 per kW-year. The generation marginal capacity costs are allocated across the RTP schedule day types and hours using the same loss-of-load expectation (LOLE) distribution reflected in the current RTP rates. Schedule TOU-8-RTP Energy Charges shall reflect a generation marginal energy cost based on a burner-tip natural gas price of $3.60 per million BTUs, as reflected in the MC/RA Settlement Agreement. Delivery service rates for Schedule TOU-8-RTP shall be the delivery service rates from the customer's Base Rate.

5) **Schedule TOU-8-RBU (Reliability Back-up Service)**

Schedule TOU-8-RBU provides customers with a service connection in addition to the customer's regular service connections, which is to be used solely for reliability or "back-up" purposes. The additional meter and service connection is installed in accordance with the Added Facilities provisions of Rule 2. This schedule shall be retained with adjustments to charges that are consistent with other schedules in the TOU-GS-3 and TOU-8 rate groups.

6) **Optimal Billing Period**

The Optimal Billing Period shall be retained, allowing customers to align their billing and production cycles twice within a six-month period.

F. Option R Rate Schedules

Option R rate schedules are available to customers with demands greater than 20 kW and who employ Renewable Distributed Generation Technologies sized to serve the customers' onsite energy needs, but whose generators (in aggregate) do not exceed four megawatts (MW) in size in aggregate. The Option R program is subject to a cumulative installed generation output capacity for all eligible rate groups of 400 MW. Eligible customers must install, own, or operate an eligible onsite Renewable Distributed Generation Technologies system with a net renewable generating capacity equal to or greater than 15 percent of the customer's annual peak demand. Customers with standalone energy storage systems or multiple onsite generation units associated with a single service account, where one or more of the generators is a non-renewable generating unit, are not eligible for the Option R schedules.

Rates for Schedules TOU-8-R, TOU-GS-3-R, and TOU-GS-2-R shall be structured to recover all generation-related capacity costs through volumetric Energy Charges on a cents-per-kWh basis in a manner that maintains the same TOU allocation of generation revenue recovery as for

Option B customers. Consistent with D.14-12-048, the distribution component of the FRD Charge shall be established to reflect both the distribution and transmission offsets, set at the following levels, relative to Option B of the Option R customers' schedules: 24.5 percent of the TOU-GS-2 distribution FRD, 37.4 percent of the TOU-GS-3 distribution FRD, 12.5 percent of the TOU-8-Secondary distribution FRD, 20.6 percent of the TOU-8-Primary distribution FRD, and 19.9 percent of the TOU-8-Subtranmission distribution FRD. The revenue deficiency resulting from this adjustment shall be collected by a non-time-differentiated, cents-per-kWh volumetric Energy Charge. FERC-jurisdictional transmission-related demand charges shall not be affected by this Agreement.

G. Time-Variant and Dynamic Pricing Rates

TOU-GS-2 Rate Group: Customers served on schedules in the TOU-GS-2 rate group shall continue to remain subject to a default TOU pricing structure, with the ability to transfer from the Default Option B rate to Option A, Option CPP, or RTP.

TOU-GS-3 and TOU-8 Rate Groups: Customers served in the TOU-GS-3 and TOU-8 rate groups shall continue to remain subject to default CPP rate structures with the ability to transfer from the default CPP rate structures to optional TOU or RTP rate structures.

1) CPP Rate Design

The CPP program design will not change from its present structure, and it shall continue to operate with 12 events per year, which events may occur on non-holiday weekdays throughout the year and may occur only during the time period from 2:00 p.m. to 6:00 p.m. The CPP rate design structure shall consist of CPP, or CPP-Lite where applicable, Energy Charges during CPP event periods and demand (or energy charge where applicable) credits, and shall be implemented as described by SCE's testimony in Exhibits SCE-04 and SCE-05, and consistent with the rates provided in Appendix B.

2) Capacity Reservation Level

Customers with demands of 200 kW or more in the TOU-GS-3 and TOU-8 rate groups may designate a fixed (positive) amount of their load that will not be subject to CPP rates during CPP events and for which the customer would not receive a CPP credit outside CPP event periods. The CRL will be set equal to or greater than zero kW, as only positive load values can be “protected” from excess energy charges under the CPP rate structure. In cases where no CRL is specified, the default CRL will be zero kW. CPP-Lite is not available to customers with demands of 200 kW or more.

3) **<u>Bill Protection</u>**

a) **Bill Protection for Default and Optional CPP**

Customers that take default or optional service on a CPP rate schedule (with or without CRL) or a CPP-Lite rate schedule will continue to be provided 12 months of bill protection after the date they first take such service, such that bills under CPP for the first 12 months shall not exceed bills calculated pursuant to the customer’s Base Rate. Bill protection is only available for the first time that a customer service account takes service on a CPP rate schedule.

H. <u>Standby Rate Groups</u>

Standby customers with demands of more than 500 kW are classified into three rate groups, which are differentiated by the voltage at which service is provided. These rate groups are designated as TOU-8-Standby-Sec, TOU-8-Standby-Pri, and TOU-8-Standby-Sub.

Standby customers with demands of more than 500 kW who elect service under a RTP option will be placed on Schedule TOU-8-RTP-S.

The rate structures for the Standby rate groups shall be comprised of (1) Customer Charges, established equal to the Customer Charges (see Table C&I-1) for the corresponding TOU-8 rate group, *i.e.*, by delivery voltage level; (2) summer and winter TOU Energy Charges established equal to the energy charges of the corresponding TOU-8 rate group; (3) FRD Charges, which will be comprised of a CRC for the customer’s specified level of Standby Demand (see Table C&I-5), and an Excess FRD Charge (see Table C&I-5), when applicable, for demands in excess of the customer’s specified Standby Demand; (4) summer on- and mid-peak Backup TRD and Supplemental TRD Charges (see Table C&I-3); and (5) voltage discounts where applicable.

Standby rates apply to the three following types of service:

i. <u>Backup Service</u>, where customers pay a Customer Charge, Backup Demand and CRC charges, as illustrated in Appendix B and in Tables C&I-3 and C&I-5, and all TOU Energy Charges;

ii. <u>Supplemental Service</u>, where customers pay a Customer Charge, Excess FRD Charges and Supplemental TRD Charges, as illustrated in Appendix B and in Tables C&I-3 and C&I-5, and all TOU Energy Charges; and

iii. <u>Maintenance Service</u>, for Standby customers who sign and comply with a Physical Assurance Contract, which will normally consist of a Customer Charge. Customers who meet all the provisions of the Physical Assurance Contract and who schedule Maintenance Service under the terms of the Physical Assurance contract shall be exempt from the CRC. If, however, the customer requests and receives energy from SCE under the Maintenance Service provision of the Physical Assurance contract, all the Supplemental and Backup charges that apply to Standby Service, *i.e.*, applicable FRD Charges (including CRC), TRD Charges, and TOU Energy Charges, shall apply during the period SCE provides this service.

1) <u>Supplemental Contract Capacity</u>

As set forth in detail in Appendices C and D, Supplemental Contract Capacity (SCC) is the level of kW regularly served by SCE.

2) <u>Standby Demand</u>

Standby Demand represents the customer's reserve capacity in kW that SCE needs to serve when a customer's generating facility that normally serves the customer's load (which excludes load normally served by SCE) experiences a partial or a complete outage.
The level of Standby Demand shall not exceed the nameplate capacity of the customer's generating facility, and in no instances shall be less than zero. The Standby Demand is initially designated as the difference between the customer's absolute peak demand over the prior 12 months and the Supplemental Contract Capacity, as determined by the Phasing-In Standby Billing Determinants discussed in Appendix C. For new Standby service accounts without 14 months of recorded metered demand data, or where future material changes to generator or site load is expected, SCE will designate the Standby Demand based on relevant information. The Standby Demand process agreed to herein supersedes the previous Standby Demand determination levels incorporated in individual service accounts' Form 14-947.

A Confirmation Review will be performed at the request of the customer, or can be initiated by SCE, as described in Appendix C. Although the Confirmation Review may ultimately lead to a revised Standby Demand and Supplemental Contract Capacity for a customer that differs from the Algorithm-established values for that customer, the Confirmation Review may not be used to modify the Algorithm, as described in Appendix D, which is adopted in this Settlement Agreement unless this Settlement Agreement is modified or superseded. The Parties agree not to dispute the validity of the Algorithm itself, but reserve the right to dispute the *applicability* of the Algorithm to a particular customer based on that customer's operating conditions, as provided in Appendix C.

3) Study of Electric Generators

SCE shall perform a study, the results of which shall be served on the Settling Parties when SCE files its 2018 GRC Phase 2 Application (and serves its supporting testimony), that will disaggregate the cost of service attributes of the customers in the Standby class, namely, transmission, distribution and generation cost-of-service drivers on a Standby class-wide basis. Specifically, SCE shall identify the attributes of customers that are primarily merchant electric generators and that use standby service to supply auxiliary and station loads when the generator is not running, or is running at partial load and compare these attributes to the other members of the Standby class. This study will examine (1) the marginal costs of serving merchant generator customers and the remaining non-merchant generator Standby customers; (2) the level of standby and supplemental capacity for these customers assuming, only for the sake of the study, that these merchant generator customers constitute a separate rate class, and (3) the rates for backup demand and supplemental service for these merchant generator and non-merchant generator customers, using cost-of-service principles and again assuming, only for the sake of the study, that these merchant generator customers constitute a separate rate class. Any requested bill impacts would be provided in a disaggregated format by generator capacity, voltage level, and fuel source to the extent that the provision of such disaggregated results are consistent with SCE and Commission policies regarding customer-confidential data disclosure.

4) CRC

The CRC will apply to a customer's Standby Demand and will consist of: (1) a transmission component, which is established by the FERC; and (2) if applicable, a distribution component. The distribution component of the CRC is determined by adjusting the voltage level $/kW-year marginal distribution costs reflected in the MC/RA Settlement Agreement by the applicable distribution EPMC revenue scalar. The distribution cost components are then adjusted by a voltage-differentiated, effective demand factor.

For customers taking only Backup Service, the Standby CRC shall be applied to determine the customer's total FRD Charges. A customer taking both Backup and Supplemental Service shall be charged the Standby CRC and the Excess FRD to determine the customer's total FRD Charges.

5) TRD Charges

TRD Charges for Standby Service will apply to Backup and Supplemental Service and shall be designed consistent with the TRD Charges for the corresponding TOU-8 rate groups, where the value of capacity is set to $102-kW-year, with the deficiency relative to the $108-kW-year in the MC/RA Settlement Agreement recovered though TOU on- and mid-peak Energy Charges.

6) Energy Charges

All kWh usage for Standby Service, whether for Supplemental, Backup, or Maintenance Service, will be charged Energy Charges that are determined consistent with the Energy Charges for the corresponding TOU-8 rate groups.

7) TOU-8-A RES-BCT Service for Customers with Demands Greater than 500 kW

The Renewable Energy Self-Generation Bill Credit Transfer (RES-BCT) program is statutorily mandated and requires SCE to offer a tariff that allows local governments and campuses to generate electricity from an eligible renewable generating facility for their own use, and to export energy not consumed at the time of generation to SCE's grid. All such generation exported to SCE's grid is converted into bill credits and applied as dollars to benefiting accounts as designated by the local government or campus. RES-BCT service does not represent a form of NEM service, and thus customers taking RES-BCT service are not exempt from Standby service. The Settling Parties agree that RES-BCT customers with demands greater than 500 kW will be able to take service on the new Schedule TOU-8 Standby, Option A (as distinguished from the Option A of TOU-8 for PLS, Cold-Ironing and Special Solar Allowance customers), in order to avail themselves of the RES-BCT and adhere to SCE's Standby service requirements. Eligibility for Schedule TOU-8 Standby Option A will be limited to customers taking service on Schedule RES-BCT. The RES-BCT Option will be closed to new customers (in all rate groups eligible for this option) upon the sooner of the reaching of the statewide capacity cap of 250 MW, or SCE reaching 125 MW of eligible installed capacity, representing SCE's designated share of the statewide capacity cap.

All aspects of the standard TOU-8 Standby service rate structure and billing determinants will continue to apply, with the following exceptions:

a) <u>TRD Charges</u>

TRD Charges for TOU-8 Standby, Option A Service will apply only to Backup Service and shall be designed consistent with the TRD Charges for the corresponding TOU-8 rate groups, where the value of capacity is set at $102 per kW-year, with the deficiency recovered though TOU on- and mid-peak Energy Charges.

b) <u>Energy Charges</u>

All kWh usage for Standby Service, whether for Supplemental, Backup, or Maintenance Service, will be charged Energy Charges that are determined consistent with the Energy Charges for the corresponding TOU-8 rate groups. The energy rates for Schedule TOU-8 Standby, Option A, shall be structured to recover Supplemental generation-related capacity costs, in addition to generation-related energy costs, through volumetric Energy Charges on a cents-per-kWh basis.

8) <u>Standby Service for Customers With Demands Less Than 500 kW</u>

Standby customers whose demands are 500 kW or lower will be treated similarly to customers in the TOU-8-S rate groups, with respect to the general applicability of Standby Service and determination of billing determinants. However, such customers will be served on rate schedules within their applicable rate groups with rider charges for Standby service.

The Standby CRC shall be the lesser of the FRD Charge that is based on the customer's OAT or the Standby CRC specified for the TOU-8-S (Sec) rate group. For standard Standby service, the underlying Base service will be taken on Option B.

The Settling Parties agree to permit Schedule RES-BCT customers with demands of 500 kW or lower to take Standby service on an underlying Option A rate schedule.[12]

5. Implementation of Settlement Agreement

It is the intent of the Settling Parties that SCE should be authorized to implement the rates resulting from this Settlement Agreement as soon as practicable following the issuance of a final Commission decision approving this Settlement Agreement, but no earlier than January 1, 2016.

6. Incorporation of Complete Agreement

This Agreement is to be treated as a complete package and not as a collection of separate agreements on discrete issues. To accommodate the interests related to diverse issues, the Settling Parties acknowledge that changes, concessions, or compromises by a Settling Party or Settling Parties in one section of this Agreement resulted in changes, concessions, or compromises by the Settling Parties in other sections. Consequently, the Settling Parties agree to oppose any modification of this Agreement not agreed to by all Settling Parties. If the Commission does not approve this Agreement without modification, the terms and conditions reflected in this Agreement shall no longer apply to the Settling Parties.

7. Record Evidence

The Settling Parties request that all of their related prepared testimony be admitted as part of the evidentiary record for this proceeding.

8. Signature Date

This Settlement Agreement shall become binding as of the last signature date of the Settling Parties.

9. Regulatory Approval

The Settling Parties, by signing this Agreement, acknowledge that they support Commission approval of this Agreement and subsequent implementation of all the provisions of the Agreement

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[12] This change is intended to restore these customers to the position in which they stood before SCE's 2012 GRC Phase 2.

for the duration of rates implemented pursuant to a Commission order adopting this Agreement in this proceeding, *i.e.*, Phase 2 of SCE's Test Year 2015 GRC. The Settling Parties shall use their best efforts to obtain Commission approval of the Agreement. The Settling Parties shall jointly request that the Commission approve the Agreement without change, and find the Agreement to be reasonable, consistent with law and in the public interest.

Should any Proposed Decision or Alternate Proposed Decision seek a modification to this Settlement Agreement, and should any Settling Party be unwilling to accept such modification, that Settling Party shall so notify the other Settling Parties within five business days of issuance of such Proposed Decision or Alternate Proposed Decision. The Settling Parties shall thereafter promptly discuss the proposed modification and negotiate in good faith to achieve a resolution acceptable to the Settling Parties, and shall promptly seek Commission approval of the resolution so achieved. Failure to resolve such proposed modification to the satisfaction of the Settling Parties, or to obtain Commission approval of such resolution promptly thereafter, shall entitle any Settling Party to terminate its participation from this Agreement through prompt notice to the other Settling Parties.

10. Compromise of Disputed Claims

This Settlement Agreement represents a compromise of disputed claims between the Settling Parties. The Settling Parties have reached this Settlement Agreement after taking into account the possibility that each Party may or may not prevail on any given issue. The Settling Parties assert that this Settlement Agreement is reasonable, consistent with law and in the public interest.

11. Non-Precedential

Consistent with Rule 12.5 of the Commission's Rules of Practice and Procedure, this Settlement Agreement is not precedential in any other pending or future proceeding before this Commission, except as expressly provided in this Settlement Agreement or unless the Commission expressly provides otherwise.

The Settling Parties expressly recognize that each Party may advocate a position that is inconsistent with this Agreement in Phase 2 of SCE's 2018 GRC, or earlier if invited to do so by the Commission in, for example, a relevant Rulemaking proceeding.

12. Previous Communications

The Settlement Agreement contains the entire agreement and understanding between the Settling Parties as to the subject matter of this Settlement Agreement. In the event there is any conflict between the terms and scope of this Settlement Agreement and the terms and scope of the accompanying joint motion in support of the Settlement Agreement, the Settlement Agreement shall govern.

13. <u>Non-Waiver</u>

None of the provisions of this Settlement Agreement shall be considered waived by any Party unless such waiver is given in writing. The failure of a Party to insist in any one or more instances upon strict performance of any of the provisions of this Settlement Agreement or take advantage of any of their rights hereunder shall not be construed as a waiver of any such provisions or the relinquishment of any such rights for the future, but the same shall continue and remain in full force and effect.

14. <u>Effect of Subject Headings</u>

Subject headings in this Settlement Agreement are inserted for convenience only, and shall not be construed as interpretations of the text.

15. <u>Governing Law</u>

This Settlement Agreement shall be interpreted, governed and construed under the laws of the State of California, including Commission decisions, orders and rulings, as if executed and to be performed wholly within the State of California.

16. <u>Number of Originals</u>

This Settlement Agreement is executed in counterparts, each of which shall be deemed an original. The undersigned represent that they are authorized to sign on behalf of the Party represented.

Dated: October 28, 2015

SOUTHERN CALIFORNIA EDISON COMPANY

Russell G. Worden

By: Russell G. Worden
Title: Managing Director, State Regulatory Operations

Dated: October 28, 2015

FEDERAL EXECUTIVE AGENCIES

/s/ Rita M. Liotta

By: Rita M. Liotta
Title: Counsel

Dated: October 28, 2015

CALIFORNIA MANUFACTURERS & TECHNOLOGY ASSOCIATION

/s/ Ronald Liebert

By: Ronald Liebert
Title: Attorney

Dated: October 28, 2015

ENERGY USERS FORUM

Carolyn Kehrein

By: Carolyn Kehrein
Title: Consultant

Dated: October 28, 2015

CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION

Nora Sheriff

By: Nora Sheriff
Title: Counsel

Dated: October 27, 2015

INDEPENDENT ENERGY PRODUCERS ASSOCIATION

/s/ Brian Cragg

By: Brian Cragg
Title: Counsel

Dated: October 28, 2015

SOLAR ENERGY INDUSTRIES ASSOCIATION

/s/ Sean Gallagher

By: Sean Gallagher
Title: Vice President of State Affairs

Dated: October 28, 2015

ENERGY PRODUCERS AND USERS COALITION

/s/ Katy Morsony

By: Katy Morsony
Title: Counsel

Dated: October 27, 2015

ASSOCIATION OF CALIFORNIA WATER AGENCIES

/s/ Lon House

By: Lon House
Title: Energy Advisor

Appendix A

Comparison Of Party Positions On Medium and Large Power Rate Group Rate Design Issues and Settlement

Issue	Current Treatment (*i.e.*, 2012 GRC Settled Position)	SCE	CLECA/CMTA	SEIA	EUF	EPUC	FEA	IEP	2015 GRC Settled Position
Customer Charges	Set at full EPMC levels.	Set at full EPMC levels.	Set at full EPMC levels.	No comment	No comment	No comment	No comment	No Comment	Set at full EPMC levels for all C&I rate groups.
Facilities-Related Demand Charges (i.e., Peak Demand-Related Charges)	Monthly $ per kW charge; not differentiated by TOU period or season, set at the cost-based level established in the MC/RA Settlement Agreement in the 2012 GRC.	Monthly $ per kW charge; not differentiated by TOU period or season, and set at full EPMC-based level.	Agrees w/ SCE's facilities-related demand charges for recovering distribution capacity-related costs on a non-TOU basis.	No comment	No comment	No comment	No comment	No Comment	Monthly $ per kW charge; not differentiated by TOU period or season, set at the cost-based level established in the MC/RA Settlement Agreement.
Time-Related Demand Charges	Set TRD Charges based on a capacity cost of $95 per kW-year, with the revenue shortfall relative to the $114 per kW-year value that is reflected in the MC/RA Settlement Agreement recovered through the summer on- and mid-peak Energy Charges.	$ per kW charges based on LOLE-weighted marginal cost of generation capacity, scaled to recover total allocated SCE generation revenues in combination with TOU energy charges.	Proposes to increase the summer on-peak and to decrease the summer mid-peak demand charges from current levels as SCE's proposed full EPMC increases would have large impacts for one case cycle. Supports SCE's approach to include the summer off-peak capacity allocation to the summer mid-peak demand charges	Cites D.14-12-080 in PG&E's 2013 RDW which confirms that TOU energy rates in Options A and R rates are the appropriate way to recover generation-related, coincident-peak capacity costs from solar customers.	No comment	Based on EPUC's GCMC marginal cost value of $ 199.48/kW-year and SCE's errata revenue allocation and rate design models.	No comment	No Comment	Set TRD Charges based on a capacity cost of $102 per kW-year for customers C&I >500kW and $95 per kW-year for C&I customers <500kW, with the revenue shortfall relative to the $108 per kW-year value that is reflected in the MC/RA Settlement Agreement recovered through the summer on- and mid-peak Energy Charges.
TOU Energy Charges	Set TOU Energy Charges using the MECs and TOU shaping proposed by EPUC that are reflected in the MC/RA Settlement Agreement.	Set Energy Charges based on SCE's proposed generation marginal energy costs (MECs).	Propose energy charges for TOU-8-SUB and TOU-8-PRI start with CLECA's adjusted MECs, which are lower than those of SCE and somewhat differently shaped; maintain a significant cost-based differential between the on-/mid-/off-peak energy charges, to maintain the price signal for shifting load	Same as noted above.	No comment	No comment	No comment	No Comment	Set TOU Energy Charges using the MECs and TOU shaping proposed by EPUC that are reflected in the MC/RA Settlement Agreement. Includes an RPS adder with a value of 0.6¢/kWh

Issue	Current Treatment (*i.e.*, 2012 GRC Settled Position)	SCE	CLECA/CMTA	SEIA	EUF	EPUC	FEA	IEP	2015 GRC Settled Position
			off-peak						
TOU Periods and Critical Peak Pricing (CPP)	No change to TOU periods. Maintain existing program design; offer a capacity reservation level (CRL) option to CPP customers with demands exceeding 200kW. Energy Charges for CPP Events as indicated in Appendix B. CPP CRL must be greater than or equal to zero. Default CPP issue for small and medium commercial customers was addressed in a different settlement by a recommendation to defer indefinitely (a provision the Commission rejected).	Consider modifying TOU periods in 2018 rate case. Default CPP in April 2017. Maintain existing CPP rate structure and program design. Continue to provide 12 months of bill protection, such that bills under CPP for the first 12 months shall not exceed bills calculated on the customers Base Rate.	TOU periods should be revised no later than the 2015 rate design window based on forecast change in net load shapes.	Med/Large C&I customers on Option A and Option R rates should be allowed to participate in CPP; and CPP rates should be revenue neutral to Option A and R rates. Solar customers with demands > 200 kW on CPP or CPP-Lite should not be limited by CRL to earn NEM credits on CPP event days.	SCE should revisit definition of TOU periods, which should also consider the Net Demand for each hour and intra-hours using CAISO definition of Net Demand. SCE should provide a more thorough analysis no later than its next GRC.	No Comment	No Comment	No Comment	Consistent with the uncontested RA/MC Settlement Agreement, SCE to propose TOU periods in SCE's 2016 Rate Design Window (RDW) Application. Defer CPP migration to 2018 to align with the redefinition of TOU periods. Maintain existing rate structure and program design. CPP Energy Charges and Credits for CPP Events as indicated in Appendix B. Continue to provide 12 months of bill protection, such that bills under CPP for the first 12 months shall not exceed bills calculated on the customers Base Rate. CPP CRL is available to TOU GS-3 and TOU-8 rate groups, who may designate their CRL at any percentage of their maximum demand. Maintain requirement that CPP CRL must be greater than or equal to zero.
Standby Rates	Create 3 separate Large Power Standby rate groups. Include supplemental and	Proposes a new Algorithm to refine the current process to differentiate between supplemental vs.	Disagrees with SCE's proposed inclusion of supplemental service loads in the Standby rate group.	Does not oppose SCE's proposed revisions to the "Daily Max" method to determine	Supports SCE's proposal to change the method for determining backup and supplemental	Generally supports SCE's proposal to use a new algorithm to establish the supplemental vs. backup load; indicates a	Generally supports SCE's proposed algorithm. However, there needs to be the opportunity for	Opposes SCE's proposed algorithm and methodology	Permit RES-BCT customers with demands < 500kW to take Standby service on an underlying Option A rate schedule;

Issue	Current Treatment (*i.e.*, 2012 GRC Settled Position)	SCE	CLECA/CMTA	SEIA	EUF	EPUC	FEA	IEP	2015 GRC Settled Position
	back-up loads in new class, but maintain distinction between each service type and applicable charges. Include tariff language clarifying how Supplemental Contract will be determined. Currently, supplemental and backup billing attributes are merged, then allocated revenue to a combined Standby class; the pricing of the two different types of standby service is determined in the rate design process of the Standby rate development	backup load. For standby customers with demands >500kW, separate backup load attributes from supplemental load attributes prior to performing revenue allocation and rate design.	Tentatively support SCE's algorithm with the modifications proposed by EPUC.	backup demand of standby customers. Strongly supports SCE's plan to phase-in the new method over several years.	service levels for Standby customers over 500 kW	shortcoming of SCE's proposal is in the lack of a structured procedure for customer input (i.e., CHP facilities should be allowed to purchase standby demands up to the capability of their generation which may be greater than that calculated by the Algorithm). Agrees with SCE's proposal to separate supplemental and backup load attributes prior to performing revenue allocation.	meaningful customer input to ensure that the amounts calculated as standby capacity are reasonable. This opportunity should not be viewed as an attempt to "get around" the mathematical results, but rather one designed to make the answer more suitable for the individual customers' operations.	to include billing determinants of the merchant generators in the TOU-8 class and derive rates in this manner. SCE should be directed to develop a standby tariff for merchant generators (i.e., utility-scale grid connected electric generators) that reflects their cost of service and have different options for different types of merchant generators (e.g., solar, wind, gas-fired) and for different voltage levels. Commission should order stakeholder workshops to facilitate a process for determining the proper way to allocate costs and determine	RES-BCT customers with demands > 500 kW will be able to take service on the new Schedule TOU-8 Standby, Option A Eligibility for Schedule TOU-8 Standby, Option A will be limited to customers taking service on Schedule RES-BCT. Algorithm adopted with the addition of a Phase In and Confirmation Review process.

Issue	Current Treatment (*i.e.*, 2012 GRC Settled Position)	SCE	CLECA/CMTA	SEIA	EUF	EPUC	FEA	IEP	2015 GRC Settled Position
								standby rates for merchant generators.	
RES-BCT	Changes made to standby rates resulting from 2012 GRC resulting in rendering RES-BCT customers under 500kW ineligible to take service under Rates A and R. This was due to standby rates containing time-related demand charges, which have traditionally been inconsistent with the structure of Rate A.	Proposes to permit Schedule RES-BCT customers at 500kW and below to again be eligible for Rate A-type structure (i.e., one in which generation capacity costs are recovered largely through energy rates). RES-BCT customers at 500kW and below will be eligible to take service on Rate A of TOU-GS-2, TOU-GS-3, TOU-PA-2, and TOU-PA3 subject to SCE's share of the statewide RES-BCT cap.[1]	No comment	Supports SCE's proposal to allow RES-BCT customers with demands < 500 kW to take service on Option A rates; proposes same treatment for TOU-8 RES-BCT customers.	No comment	No Comment	No Comment	No comment	Permit RES-BCT customers with demands < 500 kW to take Standby service on an underlying Option A rate schedule; RES-BCT customers with demands > 500 kW will be able to take service on the new Schedule TOU-8 Standby, Option A. RES-BCT will be closed to all new customers upon the sooner of the reaching of the statewide capacity cap of 250 MW, or SCE reaching 125 MW of eligible installed capacity.
Base Interruptible Program (BIP) and Demand Bidding Program (DBP)	The credits for BIP service, including price-based and reliability-based demand response programs, shall be based on the net marginal generation capacity cost that is reflected in the MC/RA Settlement Agreement, which is a generation marginal capacity cost of $114 per kW per year, reduced by	For customers dual participating in BIP and DBP, SCE proposes that the monthly BIP credit calculation exclude days during which a DBP event is dispatched and the customer has placed a bid. Proposes a reduction in BIP credits based on its use of a $85/kW-year marginal	Strongly supports SCE's proposal to ensure that BIP incentives be calculated based on exclusion of both BIP and DBP event days for customers dual participating in BIP/DBP. Opposes SCE's proposal to reduce BIP incentives, citing proposal would be inconsistent with the	No comment	SCE should reduce incentive levels for SDP. Indulgent incentives are funded by all customers, including DA and CCA through distribution rates.	No Comment	No comment	No Comment	The credits that are provided for non-firm service, including price-based and reliability-based demand response programs, will be set at the generation marginal capacity cost of $108 per kW-year. The credits will be the average of the BIP program credits reflected in the MC/RA Settlement Agreement and by this Settlement Agreement, with the current BIP incentive values adopted in D.13-03-

1 "ACWA has been working with SCE for the last several years trying to find a solution to the problem their 2012 GRC created- the inability of RES-BCT projects to participate in the A option of the applicable tariffs. This proposal by SCE rectifies many of those problems, and ACWA wants to go on record as supporting their proposal." *See* Direct Testimony of ACWA, p. 8.

Issue	Current Treatment (*i.e.*, 2012 GRC Settled Position)	SCE	CLECA/CMTA	SEIA	EUF	EPUC	FEA	IEP	2015 GRC Settled Position
	a 5.6 percent general plant loader, yielding a value of $107.6 per kW per year.	generation capacity cost.	direction of the Commission to allow "programs and activities to continue, as is" in D.14-12-024. Recommends SCE to use full avoided CT cost of $115.14/kW combined with the updated 2017 LOLE study to develop the BIP incentives.						031.

Appendix B

Illustrative Medium and Large Power Rate Group Rates

COMPARISON OF JANUARY 2015 TO ILLUSTRATIVE 2016 SETTLEMENT RATES

	January 2015 Rates			Proposed 2015 GRC Rates			
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
GS-2 (Non TOU Rate)							
Energy Charge - $/kWh							
Summer	0.02873	0.06369	0.09242	0.02702	0.06509	0.09211	-0.3%
Winter	0.02873	0.05401	0.08274	0.02702	0.05520	0.08222	-0.6%
Customer Charge - $/month	198.79	0.00	198.79	202.25		202.25	1.7%
Facilities Related Demand Charge - $/kW	13.20	0.00	13.20	13.37		13.37	1.3%
Summer Time Related Demand Charge - $/kW	0.00	22.21	22.21	0.00	22.70	22.70	2.2%
Single Phase Service - $/month	(12.79)	0.00	(12.79)	(13.01)	0.00	(13.01)	-1.7%
Voltage Discount, Facilities Related Demand - $/kW							
From 2 kV to 50 kV	(0.18)	0.00	(0.18)	(0.18)		(0.18)	0.0%
From 51 kV to 219 kV	(5.78)	0.00	(5.78)	(5.78)		(5.78)	0.0%
220 kV and above	(9.96)	0.00	(9.96)	(9.96)		(9.96)	0.0%
Voltage Discount, Time-Related Demand - $/kW							
From 2 kV to 50 kV	0.00	(0.59)	(0.59)	0.00	(0.59)	(0.59)	0.0%
From 51 kV to 219 kV	0.00	(1.63)	(1.63)	0.00	(1.63)	(1.63)	0.0%
220 kV and above	0.00	(1.65)	(1.65)	0.00	(1.65)	(1.65)	0.0%
Voltage Discount, Energy - $/kWh							
From 2 kV to 50 kV	0.00000	(0.00108)	(0.00108)	0.00000	(0.00108)	(0.00108)	0.0%
From 51 kV to 219 kV	0.00000	(0.00242)	(0.00242)	0.00000	(0.00242)	(0.00242)	0.0%
220 kV and above	0.00000	(0.00244)	(0.00244)	0.00000	(0.00244)	(0.00244)	0.0%
Bill Limiter (GS-1 to GS-2) - %	20.89%	79.11%	100.00%	20.89%	79.11%	100.00%	0.00%
California Climate Credit - $/kWh/Meter/Month	(0.00794)	0.00000	(0.00794)	(0.00669)	0.00000	(0.00669)	15.7%
GS-2 (TOU Rate A)							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.02873	0.33333	0.36206	0.02702	0.38599	0.41301	14.1%
Mid-peak	0.02873	0.11707	0.14580	0.02702	0.10883	0.13585	-6.8%
Off-Peak	0.02873	0.03747	0.06620	0.02702	0.03900	0.06602	-0.3%
Winter Season							
Mid-peak	0.02873	0.06562	0.09435	0.02702	0.05893	0.08595	-8.9%
Off-Peak	0.02873	0.04275	0.07148	0.02702	0.04619	0.07321	2.4%
Customer Charge - $/month	198.79	0.00	198.79	202.00		202.00	1.6%
Facilities Related Demand Charge - $/kW	13.20	0.00	13.20	13.43		13.43	1.7%
Single Phase Service - $/month	(12.79)	0.00	(12.79)	(11.89)	0.00	(11.89)	7.0%
Voltage Discount, Facilities Related Demand - $/kW							
From 2 kV to 50 kV	(0.18)	0.00	(0.18)	(0.20)		(0.20)	-11.1%
From 51 kV to 219 kV	(5.78)	0.00	(5.78)	(6.93)		(6.93)	-19.9%
220 kV and above	(9.96)	0.00	(9.96)	(10.19)		(10.19)	-2.3%
Voltage Discount, Energy - $/kWh							
From 2 kV to 50 kV	0.00000	(0.00183)	(0.00183)	0.00000	(0.00145)	(0.00145)	20.8%
From 51 kV to 219 kV	0.00000	(0.00448)	(0.00448)	0.00000	(0.00341)	(0.00341)	23.9%
220 kV and above	0.00000	(0.00453)	(0.00453)	0.00000	(0.00344)	(0.00344)	24.1%
TOU Rate Meter Charge - $/month							
TOU-RTEM	73.20	0.00	73.20	64.08		64.08	-12.5%
California Climate Credit - $/kWh/Meter/Month	(0.00794)	0.00000	(0.00794)	(0.00669)		(0.00669)	0.15743

	January 2015 Rates			Proposed 2015 GRC Rates			
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
GS-2 (TOU Rate B)							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.02873	0.10818	0.13691	0.02702	0.11005	0.13707	0.1%
Mid-peak	0.02873	0.06074	0.08947	0.02702	0.06360	0.09062	1.3%
Off-Peak	0.02873	0.03747	0.06620	0.02702	0.03900	0.06602	-0.3%
Winter Season							
Mid-peak	0.02873	0.06562	0.09435	0.02702	0.05893	0.08595	-8.9%
Off-Peak	0.02873	0.04275	0.07148	0.02702	0.04619	0.07321	2.4%
Customer Charge - $/month	198.79	0.00	198.79	202.00		202.00	1.6%
Facilities Related Demand Charge - $/kW	13.20	0.00	13.20	13.43		13.43	1.7%
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak	0.00	18.43	18.43	0.00	21.38	21.38	16.0%
Mid-Peak	0.00	5.39	5.39	0.00	4.19	4.19	-22.3%
Single Phase Service - $/month	(12.79)	0.00	(12.79)	(11.89)	0.00	(11.89)	7.0%
Voltage Discount, Facilities Related Demand - $/kW							
From 2 kV to 50 kV	(0.18)	0.00	(0.18)	(0.20)		(0.20)	-11.1%
From 51 kV to 219 kV	(5.78)	0.00	(5.78)	(6.93)		(6.93)	-19.9%
220 kV and above	(9.96)	0.00	(9.96)	(10.19)		(10.19)	-2.3%
Voltage Discount, Time-Related Demand - $/kW							
From 2 kV to 50 kV	0.00	(0.71)	(0.71)	0.00	(0.29)	(0.29)	59.2%
From 51 kV to 219 kV	0.00	(1.97)	(1.97)	0.00	(0.80)	(0.80)	59.4%
220 kV and above	0.00	(1.99)	(1.99)	0.00	(0.81)	(0.81)	59.3%
Voltage Discount, Energy - $/kWh							
From 2 kV to 50 kV	0.00000	(0.00108)	(0.00108)	0.00000	(0.00108)	(0.00108)	0.0%
From 51 kV to 219 kV	0.00000	(0.00242)	(0.00242)	0.00000	(0.00239)	(0.00239)	1.2%
220 kV and above	0.00000	(0.00244)	(0.00244)	0.00000	(0.00241)	(0.00241)	1.2%
TOU Rate Meter Charge - $/month							
TOU-RTEM	73.20	0.00	73.20	64.08	0.00	64.08	-12.5%
California Climate Credit - $/kWh/Meter/Month	(0.00794)	0.00000	(0.00794)	(0.00669)	0.00000	(0.00669)	0.15743
GS-2 (TOU Rate R)							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.03975	0.33333	0.37308	0.03775	0.38599	0.42374	13.6%
Mid-peak	0.03975	0.11707	0.15682	0.03775	0.10883	0.14658	-6.5%
Off-Peak	0.03975	0.03747	0.07722	0.03775	0.03900	0.07675	-0.6%
Winter Season							
Mid-peak	0.03975	0.06562	0.10537	0.03775	0.05893	0.09668	-8.2%
Off-Peak	0.03975	0.04275	0.08250	0.03775	0.04619	0.08394	1.7%
Customer Charge - $/month	198.79	0.00	198.79	202.00		202.00	1.6%
Facilities Related Demand Charge - $/kW	9.97	0.00	9.97	10.14	0.00	10.14	1.7%
Single Phase Service - $/month	(12.79)	0.00	(12.79)	(11.89)	0.00	(11.89)	7.0%
Voltage Discount, Facilities Related Demand - $/kW							
From 2 kV to 50 kV	(0.12)	0.00	(0.12)	(0.14)	0.00	(0.14)	-16.7%
From 51 kV to 219 kV	(3.90)	0.00	(3.90)	(4.69)	0.00	(4.69)	-20.3%
220 kV and above	(6.73)	0.00	(6.73)	(6.90)	0.00	(6.90)	-2.5%
Voltage Discount, Energy - $/kWh							
From 2 kV to 50 kV	(0.00020)	(0.00183)	(0.00203)	(0.00021)	(0.00145)	(0.00166)	18.2%
From 51 kV to 219 kV	(0.00640)	(0.00448)	(0.01088)	(0.00730)	(0.00341)	(0.01071)	1.6%
220 kV and above	(0.01102)	(0.00453)	(0.01555)	(0.01073)	(0.00344)	(0.01417)	8.9%
TOU Rate Meter Charge - $/month							
TOU-RTEM	73.20	0.00	73.20	64.08	0.00	64.08	-12.5%
California Climate Credit - $/kWh/Meter/Month	(0.00794)	0.00000	(0.00794)	(0.00669)	0.00000	(0.00669)	0.15743

	January 2015 Rates			Proposed 2015 GRC Rates			
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
TOU-GS-2-CPP							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.02873	0.10818	0.13691	0.02702	0.11005	0.13707	0.1%
Mid-peak	0.02873	0.06074	0.08947	0.02702	0.06360	0.09062	1.3%
Off-Peak	0.02873	0.03747	0.06620	0.02702	0.03900	0.06602	-0.3%
Winter Season							
Mid-peak	0.02873	0.06562	0.09435	0.02702	0.05893	0.08595	-8.9%
Off-Peak	0.02873	0.04275	0.07148	0.02702	0.04619	0.07321	2.4%
Customer Charge - $/month	198.79	0.00	198.79	202.00		202.00	1.6%
Single Phase Service - $/month	(12.79)	0.00	(12.79)	(11.89)		(11.89)	7.0%
Facilities Related Demand Charge - $/kW	13.20	0.00	13.20	13.43	0.00	13.43	1.7%
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak	0.00	18.43	18.43	0.00	21.38	21.38	16.0%
Mid-Peak	0.00	5.39	5.39	0.00	4.19	4.19	-22.3%
Voltage Discount, Facilities Related Demand - $/kW							
From 2 kV to 50 kV	(0.18)	0.00	(0.18)	(0.20)	0.00	(0.20)	-11.1%
Above 50 kV but below 220 kV	(5.78)	0.00	(5.78)	(6.93)	0.00	(6.93)	-19.9%
At 220 kV	(9.96)	0.00	(9.96)	(10.19)	0.00	(10.19)	-2.3%
Voltage Discount, Time-Related Demand - $/kW							
From 2 kV to 50 kV	0.00	(0.71)	(0.71)	0.00	(0.29)	(0.29)	59.2%
Above 50 kV but below 220 kV	0.00	(1.97)	(1.97)	0.00	(0.80)	(0.80)	59.4%
At 220 kV	0.00	(1.99)	(1.99)	0.00	(0.81)	(0.81)	59.3%
Voltage Discount, Energy - $/kWh							
From 2 kV to 50 kV	0.00000	(0.00108)	(0.00108)	0.00000	(0.00108)	(0.00108)	0.0%
Above 50 kV but below 220 kV	0.00000	(0.00242)	(0.00242)	0.00000	(0.00239)	(0.00239)	1.2%
At 220 kV	0.00000	(0.00244)	(0.00244)	0.00000	(0.00241)	(0.00241)	1.2%
TOU Rate Meter Charge - $/month							
TOU-RTEM	73.20	0.00	73.20	64.08	0.00	64.08	-12.5%
CPP-Lite Event Energy Charge - $/kWh	0.00000	0.68727	0.68727	0.00000	0.68727	0.68727	0.0%
Summer CPP-Lite Non-Event Credit							
On-Peak Demand Credit - $/kW	0.00	(5.38)	(5.38)	0.00	(5.38)	(5.38)	0.0%
California Climate Credit - $/kWh/Meter/Month	(0.00794)	0.00000	(0.00794)	(0.00669)	0.00000	(0.00669)	15.7%
TOU-GS-2-RTP							
Energy Charge - $/kWh	0.02873	Variable*	Variable*	0.02702	Variable*	Variable*	
Customer Charge - $/month	198.79	0.00	198.79	202.00		202.00	1.6%
Single Phase Service - $/month	(12.79)	0.00	(12.79)	(11.89)		(11.89)	7.0%
Facilities Related Demand Charge - $/kW	13.20	0.00	13.20	13.43		13.43	1.7%
Voltage Discount, Facilities Related Demand - $/kW							
From 2 kV to 50 kV	(0.18)	0.00	(0.18)	(0.20)		(0.20)	-11.1%
Above 50 kV but below 220 kV	(5.78)	0.00	(5.78)	(6.93)		(6.93)	-19.9%
At 220 kV	(9.96)	0.00	(9.96)	(10.19)		(10.19)	-2.3%
Voltage Discount, Energy - $/kWh							
From 2 kV to 50 kV	0.00000	(0.00183)	(0.00183)	0.00000	(0.00145)	(0.00145)	20.8%
Above 50 kV but below 220 kV	0.00000	(0.00448)	(0.00448)	0.00000	(0.00341)	(0.00341)	23.9%
At 220 kV	0.00000	(0.00453)	(0.00453)	0.00000	(0.00344)	(0.00344)	24.1%
TOU Rate Meter Charge - $/month							
TOU-RTEM	73.20	0.00	73.20	64.08		64.08	
California Climate Credit - $/kWh/Meter/Month	(0.00794)	0.00000	(0.00794)	(0.00669)	0.00000	(0.00669)	15.7%

	January 2015 Rates			Proposed 2015 GRC Rates			
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
GS-APS-E (Schedules: GS-1 or TOU-GS-1)							
Air Conditioning Cycling Credit - $/ton/summer season day							
30% Cycling	(0.03)	0.00	(0.03)	(0.03)	0.00	(0.03)	0.0%
40% Cycling	0.00	0.00	0.00	0.00	0.00	0.00	0.0%
50% Cycling	(0.15)	0.00	(0.15)	(0.15)	0.00	(0.15)	0.0%
100% Cycling	(0.42)	0.00	(0.42)	(0.42)	0.00	(0.42)	0.0%
GS-APS-E (Schedules: GS-2, TOU-GS-2, TOU-GS-3, or TOU-8)							
Air Conditioning Cycling Credit - $/ton/summer season month							
30% Cycling	(0.89)	0.00	(0.89)	(0.89)	0.00	(0.89)	0.0%
40% Cycling	0.00	0.00	0.00	0.00	0.00	0.00	
50% Cycling	(4.44)	0.00	(4.44)	(4.44)	0.00	(4.44)	0.0%
100% Cycling	(12.69)	0.00	(12.69)	(12.69)	0.00	(12.69)	0.0%
TOU-EV-4							
Energy Charge - $/kWh							
Summer Season On-Peak	0.02873	0.26160	0.29033	0.02702	0.27992	0.30694	5.7%
Mid-Peak	0.02873	0.09375	0.12248	0.02702	0.07904	0.10606	-13.4%
Off-Peak	0.02873	0.02483	0.05356	0.02702	0.03345	0.06047	12.9%
Winter Season On-Peak	0.02873	0.07890	0.10763	0.02702	0.07322	0.10024	-6.9%
Mid-Peak	0.02873	0.06529	0.09402	0.02702	0.06222	0.08924	-5.1%
Off-Peak	0.02873	0.03371	0.06244	0.02702	0.03809	0.06511	
Customer Charge - $/meter/month	198.79	0.00	198.79	202.00		202.00	1.6%
Facilities Related							
Demand Charge - $/kW	13.20	0.00	13.20	13.43		13.43	1.7%
Time Related							
Demand Charge - $/kW	0.00	0.00	0.00	0.00	0.00	0.00	
Voltage Discount, Facilities Related Demand - $/kW							
From 2 kV to 50 kV	(0.18)	0.00	(0.18)	(0.20)	0.00	(0.20)	-11.1%
From 51 kV to 219 kV	(5.78)	0.00	(5.78)	(6.93)	0.00	(6.93)	-19.9%
220 kV and above	(9.96)	0.00	(9.96)	(10.19)	0.00	(10.19)	-2.3%
Voltage Discount, Time-Related Demand - $/kW							
From 2 kV to 50 kV	0.00	0.00	0.00	0.00	0.00	0.00	
From 51 kV to 219 kV	0.00	0.00	0.00	0.00	0.00	0.00	
220 kV and above	0.00	0.00	0.00	0.00	0.00	0.00	
Voltage Discount, Energy - $/kWh							
From 2 kV to 50 kV	0.00000	(0.00108)	(0.00108)	0.00000	(0.00108)	(0.00108)	
From 51 kV to 219 kV	0.00000	(0.00242)	(0.00242)	0.00000	(0.00239)	(0.00239)	
220 kV and above	0.00000	(0.00244)	(0.00244)	0.00000	(0.00241)	(0.00241)	
Power Factor Adjustment - $/kVA							
Greater than 50 kV	0.34	0.00	0.34	0.47	0.00	0.47	38.2%
50 kV or less	0.51	0.00	0.51	0.55	0.00	0.55	7.8%
California Climate Credit - $/kWh/Meter/Month	(0.00794)	0.00000	(0.00794)	(0.00669)	0.00000	(0.00669)	15.7%

	January 2015 Rates			Proposed 2015 GRC Rates			
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
TOU-GS-3 (Rate A)							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.02691	0.33132	0.35823	0.02552	0.36254	0.38806	8.3%
Mid-peak	0.02691	0.11190	0.13881	0.02552	0.10349	0.12901	-7.1%
Off-Peak	0.02691	0.03555	0.06246	0.02552	0.04015	0.06567	5.1%
Winter Season							
Mid-peak	0.02691	0.06148	0.08839	0.02552	0.05804	0.08356	-5.5%
Off-Peak	0.02691	0.04055	0.06746	0.02552	0.04619	0.07171	6.3%
Customer Charge - $/month	441.93	0.00	441.93	409.00	0.00	409.00	-7.5%
Facilities Related							
Demand Charge - $/kW	16.37	0.00	16.37	15.99	0.00	15.99	-2.3%
Voltage Discount, Facilities Related Demand - $/kW							
From 2 kV to 50 kV	(0.20)	0.00	(0.20)	(0.21)	0.00	(0.21)	-5.0%
From 51 kV to 219 kV	(6.71)	0.00	(6.71)	(7.30)	0.00	(7.30)	-8.8%
220 kV and above	(12.71)	0.00	(12.71)	(12.33)	0.00	(12.33)	3.0%
Voltage Discount, Energy - $/kWh							
From 2 kV to 50 kV	0.00000	(0.00179)	(0.00179)	0.00000	(0.00168)	(0.00168)	6.1%
From 51 kV to 219 kV	0.00000	(0.00440)	(0.00440)	0.00000	(0.00403)	(0.00403)	8.4%
220 kV and above	0.00000	(0.00445)	(0.00445)	0.00000	(0.00408)	(0.00408)	8.3%
Power Factor Adjustment - $/kVA							
Greater than 50 kV	0.34	0.00	0.34	0.47	0.00	0.47	38.2%
50 kV or less	0.51	0.00	0.51	0.55	0.00	0.55	7.8%
TOU-GS-3 (Rate B)							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.02691	0.11077	0.13768	0.02552	0.10874	0.13426	-2.5%
Mid-peak	0.02691	0.05981	0.08672	0.02552	0.06327	0.08879	2.4%
Off-Peak	0.02691	0.03555	0.06246	0.02552	0.04015	0.06567	5.1%
Winter Season							
Mid-peak	0.02691	0.06148	0.08839	0.02552	0.05804	0.08356	-5.5%
Off-Peak	0.02691	0.04055	0.06746	0.02552	0.04619	0.07171	6.3%
Customer Charge - $/month	441.93	0.00	441.93	409.00	0.00	409.00	-7.5%
Facilities Related							
Demand Charge - $/kW	16.37	0.00	16.37	15.99	0.00	15.99	-2.3%
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak	0.00	18.86	18.86	0.00	21.14	21.14	12.1%
Mid-Peak	0.00	5.53	5.53	0.00	4.17	4.17	-24.6%
Winter Season							
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00	
Off-Peak	0.00	0.00	0.00	0.00	0.00	0.00	
Voltage Discount, Facilities Related Demand - $/kW							
From 2 kV to 50 kV	(0.20)	0.00	(0.20)	(0.21)	0.00	(0.21)	-5.0%
From 51 kV to 219 kV	(6.71)	0.00	(6.71)	(7.30)	0.00	(7.30)	-8.8%
220 kV and above	(12.71)	0.00	(12.71)	(12.33)	0.00	(12.33)	3.0%
Voltage Discount, Time-Related Demand - $/kW							
From 2 kV to 50 kV	0.00	(0.34)	(0.34)	0.00	(0.29)	(0.29)	14.7%
From 51 kV to 219 kV	0.00	(0.95)	(0.95)	0.00	(0.79)	(0.79)	16.8%
220 kV and above	0.00	(0.96)	(0.96)	0.00	(0.80)	(0.80)	16.7%
Voltage Discount, Energy - $/kWh							
From 2 kV to 50 kV	0.00000	(0.00108)	(0.00108)	0.00000	(0.00107)	(0.00107)	0.9%
From 51 kV to 219 kV	0.00000	(0.00241)	(0.00241)	0.00000	(0.00237)	(0.00237)	1.7%
220 kV and above	0.00000	(0.00243)	(0.00243)	0.00000	(0.00240)	(0.00240)	1.2%
Power Factor Adjustment - $/kVA							
Greater than 50 kV	0.34	0.00	0.34	0.47	0.00	0.47	38.2%
50 kV or less	0.51	0.00	0.51	0.55	0.00	0.55	7.8%

	January 2015 Rates			Proposed 2015 GRC Rates			
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
TOU-GS-3 (Rate R)							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.04445	0.33132	0.37577	0.04283	0.36254	0.40537	7.9%
Mid-peak	0.04445	0.11190	0.15635	0.04283	0.10349	0.14632	-6.4%
Off-Peak	0.04445	0.03555	0.08000	0.04283	0.04015	0.08298	3.7%
Winter Season							
Mid-peak	0.04445	0.06148	0.10593	0.04283	0.05804	0.10087	-4.8%
Off-Peak	0.04445	0.04055	0.08500	0.04283	0.04619	0.08902	4.7%
Customer Charge - $/month	441.93	0.00	441.93	409.00	0.00	409.00	-7.5%
Facilities Related							
Demand Charge - $/kW	10.25	0.00	10.25	10.01	0.00	10.01	-2.3%
Voltage Discount, Facilities Related Demand - $/kW							
From 2 kV to 50 kV	(0.10)	0.00	(0.10)	(0.11)	0.00	(0.11)	-10.0%
From 51 kV to 219 kV	(3.48)	0.00	(3.48)	(3.76)	0.00	(3.76)	-8.0%
220 kV and above	(6.59)	0.00	(6.59)	(6.35)	0.00	(6.35)	3.6%
Voltage Discount, Energy - $/kWh							
From 2 kV to 50 kV	(0.00028)	(0.00179)	(0.00207)	(0.00030)	(0.00168)	(0.00198)	4.3%
From 51 kV to 219 kV	(0.00926)	(0.00440)	(0.01366)	(0.01025)	(0.00403)	(0.01428)	-4.5%
220 kV and above	(0.01754)	(0.00445)	(0.02199)	(0.01731)	(0.00408)	(0.02139)	2.7%
Power Factor Adjustment - $/kVA							
Greater than 50 kV	0.34	0.00	0.34	0.47	0.00	0.47	38.2%
50 kV or less	0.51	0.00	0.51	0.55	0.00	0.55	7.8%
TOU-GS-3-CPP							
Critical Peak Pricing							
Time-of-Use Pricing Rate Energy Charge - $/kWh							
Summer Season							
On-Peak	0.02691	0.11077	0.13768	0.02552	0.10874	0.13426	-2.5%
Mid-peak	0.02691	0.05981	0.08672	0.02552	0.06327	0.08879	2.4%
Off-Peak	0.02691	0.03555	0.06246	0.02552	0.04015	0.06567	5.1%
Winter Season							
Mid-peak	0.02691	0.06148	0.08839	0.02552	0.05804	0.08356	-5.5%
Off-Peak	0.02691	0.04055	0.06746	0.02552	0.04619	0.07171	6.3%
Customer Charge - $/month	441.93	0.00	441.93	409.00	0.00	409.00	-7.5%
Facilities Related Demand Charge - $/kW	16.37	0.00	16.37	15.99	0.00	15.99	-2.3%
Time Related Demand Charge - $/kW							
Summer Season On-Peak	0.00	18.86	18.86	0.00	21.14	21.14	12.1%
Mid-Peak	0.00	5.53	5.53	0.00	4.17	4.17	-24.6%
Winter Season Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00	
Voltage Discount, Facilities Related Demand - $/kW							
From 2 kV to 50 kV	(0.20)	0.00	(0.20)	(0.21)	0.00	(0.21)	-5.0%
From 51 kV to 219 kV	(6.71)	0.00	(6.71)	(7.30)	0.00	(7.30)	-8.8%
220 kV and above	(12.71)	0.00	(12.71)	(12.33)	0.00	(12.33)	3.0%
Voltage Discount, Time-Related Demand - $/kW							
From 2 kV to 50 kV	0.00	(0.34)	(0.34)	0.00	(0.29)	(0.29)	14.7%
From 51 kV to 219 kV	0.00	(0.95)	(0.95)	0.00	(0.79)	(0.79)	16.8%
220 kV and above	0.00	(0.96)	(0.96)	0.00	(0.80)	(0.80)	16.7%
Voltage Discount, Energy - $/kWh							
From 2 kV to 50 kV	0.00000	(0.00108)	(0.00108)	0.00000	(0.00107)	(0.00107)	0.9%
From 51 kV to 219 kV	0.00000	(0.00241)	(0.00241)	0.00000	(0.00237)	(0.00237)	1.7%
220 kV and above	0.00000	(0.00243)	(0.00243)	0.00000	(0.00240)	(0.00240)	1.2%
Power Factor Adjustment - $/kVA							
Greater than 50 kV	0.34	0.00	0.34	0.47	0.00	0.47	38.2%
50 kV or less	0.51	0.00	0.51	0.55	0.00	0.55	7.8%
CPP Event Energy Charge - $/kWh	0.00000	1.37453	1.37453	0.00000	1.37453	1.37453	0.0%
Summer CPP Non-Event Credit							
On-Peak Demand Credit - $/kW	0.00	(11.44)	(11.44)	0.00	(11.44)	(11.44)	0.0%

	January 2015 Rates			Proposed 2015 GRC Rates			
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
TOU-GS-3-SOP							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.02691	0.15007	0.17698	0.02552	0.15118	0.17670	-0.2%
Mid-peak	0.02691	0.04953	0.07644	0.02552	0.07533	0.10085	31.9%
Super Off-Peak	0.02691	0.02667	0.05358	0.02552	0.03087	0.05639	5.2%
Winter Season							
Mid-peak	0.02691	0.06540	0.09231	0.02552	0.04788	0.07340	-20.5%
Super Off-Peak	0.02691	0.02825	0.05516	0.02552	0.03298	0.05850	6.1%
Customer Charge - $/month	441.93	0.00	441.93	409.00	0.00	409.00	-7.5%
Facilities Related							
Demand Charge - $/kW	16.37	0.00	16.37	15.99	0.00	15.99	-2.3%
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak	0.00	25.14	25.14	0.00	23.71	23.71	-5.7%
Mid-peak	0.00	0.54	0.54	0.00	0.51	0.51	-5.6%
Winter Season							
Mid-peak	0.00	0.10	0.10	0.00	0.09	0.09	-10.0%
Voltage Discount, Facilities Related Demand - $/kW							
From 2 kV to 50 kV	(0.20)	0.00	(0.20)	(0.21)	0.00	(0.21)	-5.0%
From 51 kV to 219 kV	(6.71)	0.00	(6.71)	(7.30)	0.00	(7.30)	-8.8%
220 kV and above	(12.71)	0.00	(12.71)	(12.33)	0.00	(12.33)	3.0%
Voltage Discount, Time-Related Demand - $/kW							
From 2 kV to 50 kV	0.00	(0.34)	(0.34)	0.00	(0.29)	(0.29)	14.7%
From 51 kV to 219 kV	0.00	(0.95)	(0.95)	0.00	(0.79)	(0.79)	16.8%
220 kV and above	0.00	(0.96)	(0.96)	0.00	(0.80)	(0.80)	16.7%
Voltage Discount, Energy - $/kWh							
From 2 kV to 50 kV	0.00000	(0.00108)	(0.00108)	0.00000	(0.00107)	(0.00107)	0.9%
From 51 kV to 219 kV	0.00000	(0.00241)	(0.00241)	0.00000	(0.00237)	(0.00237)	1.7%
220 kV and above	0.00000	(0.00243)	(0.00243)	0.00000	(0.00240)	(0.00240)	1.2%
Power Factor Adjustment - $/kVA							
Greater than 50 kV	0.34	0.00	0.34	0.47	0.00	0.47	38.2%
50 kV or less	0.51	0.00	0.51	0.55	0.00	0.55	7.8%
TOU-GS-3-RTP							
Energy Charge - $/kWh	0.02691	Variable*	Variable*	0.02552	Variable*	Variable*	
Customer Charge - $/month	441.93	0.00	441.93	409.00	0.00	409.00	-7.5%
Facilities Related							
Demand Charge - $/kW	16.37	0.00	16.37	15.99	0.00	15.99	-2.3%
Voltage Discount, Facilities Related Demand - $/kW							
From 2 kV to 50 kV	(0.20)	0.00	(0.20)	(0.21)	0.00	(0.21)	-5.0%
Above 50 kV but below 220 kV	(6.71)	0.00	(6.71)	(7.30)	0.00	(7.30)	-8.8%
At 220 kV	(12.71)	0.00	(12.71)	(12.33)	0.00	(12.33)	3.0%
Voltage Discount, Energy - $/kWh							
From 2 kV to 50 kV	0.00000	(0.00179)	(0.00179)	0.00000	(0.00168)	(0.00168)	6.1%
From 51 kV to 219 kV	0.00000	(0.00440)	(0.00440)	0.00000	(0.00403)	(0.00403)	8.4%
220 kV and above	0.00000	(0.00445)	(0.00445)	0.00000	(0.00408)	(0.00408)	8.3%
Power Factor Adjustment - $/kVA							
Greater than 50 kV	0.34	0.00	0.34	0.47	0.00	0.47	
50 kV or less	0.51	0.00	0.51	0.55	0.00	0.55	

	January 2015 Rates			Proposed 2015 GRC Rates			
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
TOU-8-Rate A (Below 2kV)							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.02638	0.37402	0.40040	0.02462	0.34868	0.37330	-6.8%
Mid-peak	0.02638	0.11659	0.14297	0.02462	0.09781	0.12243	-14.4%
Off-Peak	0.02638	0.03669	0.06307	0.02462	0.04039	0.06501	3.1%
Winter Season							
Mid-peak	0.02638	0.06325	0.08963	0.02462	0.05839	0.08301	-7.4%
Off-Peak	0.02638	0.04200	0.06838	0.02462	0.04647	0.07109	4.0%
Customer Charge - $/month	609.78	0.00	609.78	582.25	0.00	582.25	-4.5%
Facilities Related							
Demand Charge - $/kW	15.57	0.00	15.57	16.34	0.00	16.34	4.9%
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak							
Mid-Peak							
Winter Season							
Mid-Peak							
Off-Peak							
Power Factor Adjustment - $/kVA	0.51	0.00	0.51	0.55	0.00	0.55	7.8%
TOU-8-Rate B (Below 2kV)							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.02638	0.11720	0.14358	0.02462	0.08913	0.11375	-20.8%
Mid-peak	0.02638	0.06172	0.08810	0.02462	0.06033	0.08495	-3.6%
Off-Peak	0.02638	0.03669	0.06307	0.02462	0.04039	0.06501	3.1%
Winter Season							
Mid-peak	0.02638	0.06325	0.08963	0.02462	0.05839	0.08301	-7.4%
Off-Peak	0.02638	0.04200	0.06838	0.02462	0.04647	0.07109	4.0%
Customer Charge - $/month	609.78	0.00	609.78	582.25	0.00	582.25	-4.5%
Facilities Related							
Demand Charge - $/kW	15.57	0.00	15.57	16.34	0.00	16.34	4.9%
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak	0.00	23.35	23.35	0.00	23.18	23.18	-0.7%
Mid-Peak	0.00	6.60	6.60	0.00	4.46	4.46	-32.4%
Winter Season							
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00	
Off-Peak	0.00	0.00	0.00	0.00	0.00	0.00	
Power Factor Adjustment - $/kVA	0.51	0.00	0.51	0.55	0.00	0.55	7.8%

	January 2015 Rates			Proposed 2015 GRC Rates			
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
TOU-8 (Below 2kV) - Rate R							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.03132	0.37402	0.40534	0.02981	0.34868	0.37849	-6.6%
Mid-peak	0.03132	0.11659	0.14791	0.02981	0.09781	0.12762	-13.7%
Off-Peak	0.03132	0.03669	0.06801	0.02981	0.04039	0.07020	3.2%
Winter Season							
Mid-peak	0.03132	0.06325	0.09457	0.02981	0.05839	0.08820	-6.7%
Off-Peak	0.03132	0.04200	0.07332	0.02981	0.04647	0.07628	4.0%
Customer Charge - $/month	609.78	0.00	609.78	582.25	0.00	582.25	-4.5%
Facilities Related							
Demand Charge - $/kW	13.62	0.00	13.62	14.30	0.00	14.30	5.0%
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak							
Mid-Peak							
Winter Season							
Mid-Peak							
Off-Peak							
Power Factor Adjustment - $/kVA	0.51	0.00	0.51	0.55	0.00	0.55	7.8%
TOU-8-Rate A (From 2 kV to 50 kV)							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.02463	0.38256	0.40719	0.02324	0.35061	0.37385	-8.2%
Mid-peak	0.02463	0.11326	0.13789	0.02324	0.09458	0.11782	-14.6%
Off-Peak	0.02463	0.03537	0.06000	0.02324	0.03904	0.06228	3.8%
Winter Season							
Mid-peak	0.02463	0.06130	0.08593	0.02324	0.05649	0.07973	-7.2%
Off-Peak	0.02463	0.04081	0.06544	0.02324	0.04495	0.06819	4.2%
Customer Charge - $/month	319.47	0.00	319.47	278.00	0.00	278.00	-13.0%
Facilities Related							
Demand Charge - $/kW	14.88	0.00	14.88	16.32	0.00	16.32	9.7%
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak							
Mid-Peak							
Winter Season							
Mid-Peak							
Off-Peak							
Power Factor Adjustment - $/kVA	0.51	0.00	0.51	0.55	0.00	0.55	7.8%

	January 2015 Rates			Proposed 2015 GRC Rates			
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
TOU-8-Rate B (From 2 kV to 50 kV)							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.02463	0.11445	0.13908	0.02324	0.08687	0.11011	-20.8%
Mid-peak	0.02463	0.05948	0.08411	0.02324	0.05832	0.08156	-3.0%
Off-Peak	0.02463	0.03537	0.06000	0.02324	0.03904	0.06228	3.8%
Winter Season							
Mid-peak	0.02463	0.06130	0.08593	0.02324	0.05649	0.07973	-7.2%
Off-Peak	0.02463	0.04081	0.06544	0.02324	0.04495	0.06819	4.2%
Customer Charge - $/month	319.47	0.00	319.47	278.00	0.00	278.00	-13.0%
Facilities Related							
Demand Charge - $/kW	14.88	0.00	14.88	16.32	0.00	16.32	9.7%
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak	0.00	24.15	24.15	0.00	23.56	23.56	-2.4%
Mid-Peak	0.00	6.66	6.66	0.00	4.45	4.45	-33.2%
Winter Season							
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00	
Off-Peak	0.00	0.00	0.00	0.00	0.00	0.00	
Power Factor Adjustment - $/kVA	0.51	0.00	0.51	0.55	0.00	0.55	7.8%
TOU-8 (From 2 kV to 50 kV) - Rate R							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.03182	0.38256	0.41438	0.03108	0.35061	0.38169	-7.9%
Mid-peak	0.03182	0.11326	0.14508	0.03108	0.09458	0.12566	-13.4%
Off-Peak	0.03182	0.03537	0.06719	0.03108	0.03904	0.07012	4.4%
Winter Season							
Mid-peak	0.03182	0.06130	0.09312	0.03108	0.05649	0.08757	-6.0%
Off-Peak	0.03182	0.04081	0.07263	0.03108	0.04495	0.07603	4.7%
Customer Charge - $/month	319.47	0.00	319.47	278.00	0.00	278.00	-13.0%
Facilities Related							
Demand Charge - $/kW	11.81	0.00	11.81	12.96	0.00	12.96	9.7%
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak							
Mid-Peak							
Winter Season							
Mid-Peak							
Off-Peak							
Power Factor Adjustment - $/kVA	0.51	0.00	0.51	0.55	0.00	0.55	7.8%

	January 2015 Rates			Proposed 2015 GRC Rates			
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
TOU-8-Rate A (Above 50 kV)							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.02159	0.30760	0.32919	0.02114	0.34049	0.36163	9.9%
Mid-peak	0.02159	0.09641	0.11800	0.02114	0.08686	0.10800	-8.5%
Off-Peak	0.02159	0.03397	0.05556	0.02114	0.03698	0.05812	4.6%
Winter Season							
Mid-peak	0.02159	0.05803	0.07962	0.02114	0.05344	0.07458	-6.3%
Off-Peak	0.02159	0.03982	0.06141	0.02114	0.04269	0.06383	3.9%
Customer Charge - $/month	2,063.54	0.00	2,063.54	1897.50	0.00	1897.50	-8.0%
Facilities Related							
Demand Charge - $/kW	6.56	0.00	6.56	6.75	0.00	6.75	2.9%
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak							
Mid-Peak							
Winter Season							
Mid-Peak							
Off-Peak							
Power Factor Adjustment - $/kVA	0.34	0.00	0.34	0.47	0.00	0.47	38.2%
Voltage Discount, 220 kV and above							
Facilities Related Demand - $/	(2.93)	0.00	(2.93)	(3.12)	0.00	(3.12)	-6.5%
Time-Related Demand - $/kW							
Summer	0.00	0.00	0.00	0.00	0.00	0.00	
Energy - $/kWh	0.00000	(0.00067)	(0.00067)	0.00000	(0.00068)	(0.00068)	-1.5%
TOU-8-Rate B (Above 50 kV)							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.02159	0.09820	0.11979	0.02114	0.08110	0.10224	-14.7%
Mid-peak	0.02159	0.05491	0.07650	0.02114	0.05485	0.07599	-0.7%
Off-Peak	0.02159	0.03397	0.05556	0.02114	0.03698	0.05812	4.6%
Winter Season							
Mid-peak	0.02159	0.05803	0.07962	0.02114	0.05344	0.07458	-6.3%
Off-Peak	0.02159	0.03982	0.06141	0.02114	0.04269	0.06383	3.9%
Customer Charge - $/month	2,063.54	0.00	2,063.54	1,897.50	0.00	1,897.50	-8.0%
Facilities Related							
Demand Charge - $/kW	6.56	0.00	6.56	6.75	0.00	6.75	2.9%
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak	0.00	20.04	20.04	0.00	24.37	24.37	21.6%
Mid-Peak	0.00	5.35	5.35	0.00	4.38	4.38	-18.1%
Winter Season							
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00	
Off-Peak	0.00	0.00	0.00	0.00	0.00	0.00	
Power Factor Adjustment - $/kVA	0.34	0.00	0.34	0.47	0.00	0.47	38.2%
Voltage Discount, 220 kV and above							
Facilities Related Demand - $/kW	(2.93)	0.00	(2.93)	(3.12)	0.00	(3.12)	-6.5%
Time-Related Demand - $/kW							
Summer	0.00	(0.15)	(0.15)	0.00	(0.15)	(0.15)	0.0%
Energy - $/kWh	0.00000	(0.00047)	(0.00047)	0.00000	(0.00048)	(0.00048)	-2.1%

	January 2015 Rates			Proposed 2015 GRC Rates			
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
TOU-8 (Above 50 kV) - Rate R							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.02427	0.30760	0.33187	0.02394	0.34049	0.36443	9.8%
Mid-peak	0.02427	0.09641	0.12068	0.02394	0.08686	0.11080	-8.2%
Off-Peak	0.02427	0.03397	0.05824	0.02394	0.03698	0.06092	4.6%
Winter Season							
Mid-peak	0.02427	0.05803	0.08230	0.02394	0.05344	0.07738	-6.0%
Off-Peak	0.02427	0.03982	0.06409	0.02394	0.04269	0.06663	4.0%
Customer Charge - $/month	2,063.54	0.00	2,063.54	1897.50	0.00	1897.50	-8.0%
Facilities Related							
Demand Charge - $/kW	5.25	0.00	5.25	5.41	0.00	5.41	3.0%
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak							
Mid-Peak							
Winter Season							
Mid-Peak							
Off-Peak							
Power Factor Adjustment - $/kVA	0.34	0.00	0.34	0.47	0.00	0.47	38.2%
Voltage Discount, 220 kV and above							
Facilities Related Demand - $/	(1.62)	0.00	(1.62)	(1.78)	0.00	(1.78)	-9.9%
Time-Related Demand - $/kW							
Summer	0.00	0.00	0.00	0.00	0.00	0.00	
Energy - $/kWh	0.00000	(0.00067)	(0.00067)	0.00000	(0.00068)	(0.00068)	-1.5%
TOU-8-RBU (Below 2kV)							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.02638	0.11720	0.14358	0.02462	0.08913	0.11375	-20.8%
Mid-peak	0.02638	0.06172	0.08810	0.02462	0.06033	0.08495	-3.6%
Off-Peak	0.02638	0.03669	0.06307	0.02462	0.04039	0.06501	3.1%
Winter Season							
Mid-peak	0.02638	0.06325	0.08963	0.02462	0.05839	0.08301	-7.4%
Off-Peak	0.02638	0.04200	0.06838	0.02462	0.04647	0.07109	4.0%
Customer Charge - $/month	191.62	0.00	191.62	154.47	0.00	154.47	-19.4%
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak	0.00	23.35	23.35	0.00	23.18	23.18	-0.7%
Mid-Peak	0.00	6.60	6.60	0.00	4.46	4.46	-32.4%
Winter Season							
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00	
Off-Peak	0.00	0.00	0.00	0.00	0.00	0.00	
Power Factor Adjustment - $/kVA	0.51	0.00	0.51	0.55	0.00	0.55	7.8%

	January 2015 Rates			Proposed 2015 GRC Rates			
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
TOU-8-RBU (From 2 kV to 50 kV)							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.02463	0.11445	0.13908	0.02324	0.08687	0.11011	-20.8%
Mid-peak	0.02463	0.05948	0.08411	0.02324	0.05832	0.08156	-3.0%
Off-Peak	0.02463	0.03537	0.06000	0.02324	0.03904	0.06228	3.8%
Winter Season							
Mid-peak	0.02463	0.06130	0.08593	0.02324	0.05649	0.07973	-7.2%
Off-Peak	0.02463	0.04081	0.06544	0.02324	0.04495	0.06819	4.2%
Customer Charge - $/month	319.47	0.00	319.47	278.00	0.00	278.00	-13.0%
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak	0.00	24.15	24.15	0.00	23.56	23.56	-2.4%
Mid-Peak	0.00	6.66	6.66	0.00	4.45	4.45	-33.2%
Winter Season							
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00	
Off-Peak	0.00	0.00	0.00	0.00	0.00	0.00	
Power Factor Adjustment - $/kVA	0.51	0.00	0.51	0.55	0.00	0.55	7.8%
TOU-8-RBU (Above 50 kV)							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.02159	0.09820	0.11979	0.02114	0.08110	0.10224	-14.7%
Mid-peak	0.02159	0.05491	0.07650	0.02114	0.05485	0.07599	-0.7%
Off-Peak	0.02159	0.03397	0.05556	0.02114	0.03698	0.05812	4.6%
Winter Season							
Mid-peak	0.02159	0.05803	0.07962	0.02114	0.05344	0.07458	-6.3%
Off-Peak	0.02159	0.03982	0.06141	0.02114	0.04269	0.06383	3.9%
Customer Charge - $/month	2,063.54	0.00	2,063.54	1,897.50	0.00	1,897.50	-8.0%
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak	0.00	20.04	20.04	0.00	24.37	24.37	21.6%
Mid-Peak	0.00	5.35	5.35	0.00	4.38	4.38	-18.1%
Winter Season							
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00	
Off-Peak	0.00	0.00	0.00	0.00	0.00	0.00	
Power Factor Adjustment - $/kVA	0.34	0.00	0.34	0.47	0.00	0.47	38.2%
Voltage Discount, 220 kV and above							
Facilities Related Demand - $/kW	0.00	0.00	0.00	0.00	0.00	0.00	
Time-Related Demand - $/kW							
Summer	0.00	(0.15)	(0.15)	0.00	(0.15)	(0.15)	0.0%
Energy - $/kWh	0.00000	(0.00047)	(0.00047)	0.00000	(0.00048)	(0.00048)	-2.1%

	January 2015 Rates			Proposed 2015 GRC Rates			
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
TOU-8-CPP (Below 2kV)							
Critical Peak Pricing							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.02638	0.11720	0.14358	0.02462	0.08913	0.11375	-20.8%
Mid-peak	0.02638	0.06172	0.08810	0.02462	0.06033	0.08495	-3.6%
Off-Peak	0.02638	0.03669	0.06307	0.02462	0.04039	0.06501	3.1%
Winter Season							
Mid-peak	0.02638	0.06325	0.08963	0.02462	0.05839	0.08301	-7.4%
Off-Peak	0.02638	0.04200	0.06838	0.02462	0.04647	0.07109	4.0%
Customer Charge - $/month	609.78	0.00	609.78	582.25	0.00	582.25	-4.5%
Facilities Related							
Demand Charge - $/kW	15.57	0.00	15.57	16.34	0.00	16.34	4.9%
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak	0.00	23.35	23.35	0.00	23.18	23.18	-0.7%
Mid-Peak	0.00	6.60	6.60	0.00	4.46	4.46	-32.4%
Off-Peak	0.00	0.00	0.00				
Winter Season							
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00	
Off-Peak	0.00	0.00	0.00	0.00	0.00	0.00	
Power Factor Adjustment - $/kVA	0.51	0.00	0.51	0.55	0.00	0.55	7.8%
CPP Event Energy Charge - $/kWh	0.00000	1.37453	1.37453	0.00000	1.37453	1.37453	0.0%
Summer CPP Non-Event Credit							
On-Peak Demand Credit - $/kW	0.00	(11.93)	(11.93)	0.00	(11.93)	(11.93)	0.0%
TOU-8-CPP (From 2 kV to 50 kV)							
Critical Peak Pricing							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.02463	0.11445	0.13908	0.02324	0.08687	0.11011	-20.8%
Mid-peak	0.02463	0.05948	0.08411	0.02324	0.05832	0.08156	-3.0%
Off-Peak	0.02463	0.03537	0.06000	0.02324	0.03904	0.06228	3.8%
Winter Season							
Mid-peak	0.02463	0.06130	0.08593	0.02324	0.05649	0.07973	-7.2%
Off-Peak	0.02463	0.04081	0.06544	0.02324	0.04495	0.06819	4.2%
Customer Charge - $/month	319.47	0.00	319.47	278.00	0.00	278.00	-13.0%
Facilities Related							
Demand Charge - $/kW	14.88	0.00	14.88	16.32	0.00	16.32	9.7%
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak	0.00	24.15	24.15	0.00	23.56	23.56	-2.4%
Mid-Peak	0.00	6.66	6.66	0.00	4.45	4.45	-33.2%
Off-Peak	0.00	0.00	0.00				
Winter Season							
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00	
Off-Peak	0.00	0.00	0.00	0.00	0.00	0.00	
Power Factor Adjustment - $/kVA	0.51	0.00	0.51	0.55	0.00	0.55	7.8%
CPP Event Energy Charge - $/kWh	0.00000	1.34519	1.34519	0.00000	1.34519	1.34519	0.0%
Summer CPP Non-Event Credit							
On-Peak Demand Credit - $/kW	0.00	(11.82)	(11.82)	0.00	(11.82)	(11.82)	0.0%

	January 2015 Rates			Proposed 2015 GRC Rates			
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
TOU-8-CPP (Above 50 kV)							
Critical Peak Pricing							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.02159	0.09820	0.11979	0.02114	0.08110	0.10224	-14.7%
Mid-peak	0.02159	0.05491	0.07650	0.02114	0.05485	0.07599	-0.7%
Off-Peak	0.02159	0.03397	0.05556	0.02114	0.03698	0.05812	4.6%
Winter Season							
Mid-peak	0.02159	0.05803	0.07962	0.02114	0.05344	0.07458	-6.3%
Off-Peak	0.02159	0.03982	0.06141	0.02114	0.04269	0.06383	3.9%
Customer Charge - $/month	2,063.54	0.00	2,063.54	1,897.50	0.00	1,897.50	-8.0%
Facilities Related							
Demand Charge - $/kW	6.56	0.00	6.56	6.75	0.00	6.75	2.9%
Time Related Demand Charge - $/kW							
Summer Season							
On-Peak	0.00	20.04	20.04	0.00	24.37	24.37	21.6%
Mid-Peak	0.00	5.35	5.35	0.00	4.38	4.38	-18.1%
Off-Peak	0.00	0.00	0.00				
Winter Season							
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00	
Off-Peak	0.00	0.00	0.00	0.00	0.00	0.00	
Power Factor Adjustment - $/kVA	0.34	0.00	0.34	0.47	0.00	0.47	38.2%
CPP Event Energy Charge - $/kWh	0.00000	1.29359	1.29359	0.00000	1.29359	1.29359	0.0%
Summer CPP Non-Event Credit							
On-Peak Demand Credit - $/kW	0.00	(11.58)	(11.58)	0.00	(11.58)	(11.58)	0.0%
Voltage Discount, 220 kV and above							
Facilities Related Demand - $/kW	(2.93)	0.00	(2.93)	(3.12)	0.00	(3.12)	-6.5%
Time-Related Demand - $/kW							
Summer	0.00	(0.15)	(0.15)	0.00	(0.15)	(0.15)	0.0%
Energy - $/kWh	0.00000	(0.00047)	(0.00047)	0.00000	(0.00048)	(0.00048)	-2.1%
TOU-8-RTP							
Energy Charge - $/kWh							
Below 2 kV	0.02638	Variable*	Variable*	0.02462	Variable*	Variable*	
From 2 kV to 50 kV	0.02463	Variable*	Variable*	0.02324	Variable*	Variable*	
above 50 kV	0.02159	Variable*	Variable*	0.02114	Variable*	Variable*	
Customer Charge - $/month							
Below 2 kV	609.78	0.00	609.78	582.25	0.00	582.25	-4.5%
From 2 kV to 50 kV	319.47	0.00	319.47	278.00	0.00	278.00	-13.0%
above 50 kV	2,063.54	0.00	2,063.54	1,897.50	0.00	1,897.50	-8.0%
Facilities Related Demand Charge - $/kW							
Below 2 kV	15.57	0.00	15.57	16.34	0.00	16.34	4.9%
From 2 kV to 50 kV	14.88	0.00	14.88	16.32	0.00	16.32	9.7%
above 50 kV	6.56	0.00	6.56	6.75	0.00	6.75	2.9%
Voltage Discount, 220 kV and above							
Energy - $/kWh	0.00000	(0.00067)	(0.00067)	0.00000	(0.00068)	(0.00068)	
Facilities Related Demand - $/kW	(2.93)	0.00	(2.93)	(3.12)	0.00	(3.12)	
Power Factor Adjustment - $/kVA							
Greater than 50 kV	0.34	0.00	0.34	0.47		0.47	38.2%
50 kV or less	0.51	0.00	0.51	0.55		0.55	7.8%

	January 2015 Rates			Proposed 2015 GRC Rates			
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
TOU-BIP Rate - $/kW (Applicable: Average kW demand)							
Rate A							
BIP Rate Credit ($/KW)							
Below 2 kV - Summer Average On Peak	(20.73)	0.00	(20.73)	(23.17)		(23.17)	-11.8%
Summer Average Mid - Peak	(6.50)	0.00	(6.50)	(7.27)		(7.27)	-11.8%
Winter Average Mid - Peak	(1.34)	0.00	(1.34)	(1.50)		(1.50)	-11.9%
Excess Energy Charge - $/kWh	13.90810	0.00000	13.90810	15.22014		15.22014	9.4%
From 2 kV to 50 kV - Summer Average On Peak	(19.85)	0.00	(19.85)	(22.43)		(22.43)	-13.0%
Summer Average Mid - Peak	(5.94)	0.00	(5.94)	(6.75)		(6.75)	-13.6%
Winter Average Mid - Peak	(1.24)	0.00	(1.24)	(1.40)		(1.40)	-12.9%
Excess Energy Charge - $/kWh	13.61742	0.00000	13.61742	14.90088		14.90088	9.4%
above 50 kV - Summer Average On Peak	(18.75)	0.00	(18.75)	(19.89)		(19.89)	-6.1%
Summer Average Mid - Peak	(5.30)	0.00	(5.30)	(5.73)		(5.73)	-8.1%
Winter Average Mid - Peak	(1.11)	0.00	(1.11)	(1.20)		(1.20)	-8.1%
Excess Energy Charge - $/kWh	13.10629	0.00000	13.10629	14.34119		14.34119	9.4%
Rate B							
BIP Rate Credit ($/KW)							
Below 2 kV - Summer Average On Peak	(19.43)	0.00	(19.43)	(21.83)		(21.83)	-12.4%
Summer Average Mid - Peak	(6.09)	0.00	(6.09)	(6.85)		(6.85)	-12.5%
Winter Average Mid - Peak	(1.26)	0.00	(1.26)	(1.42)		(1.42)	-12.7%
Excess Energy Charge - $/kWh	12.97203	0.00000	12.97203	14.28419		14.28419	10.1%
From 2 kV to 50 kV - Summer Average On Peak	(18.55)	0.00	(18.55)	(21.09)		(21.09)	-13.7%
Summer Average Mid - Peak	(5.55)	0.00	(5.55)	(6.35)		(6.35)	-14.4%
Winter Average Mid - Peak	(1.16)	0.00	(1.16)	(1.32)		(1.32)	-13.8%
Excess Energy Charge - $/kWh	12.70134	0.00000	12.70134	13.98491		13.98491	10.1%
above 50 kV - Summer Average On Peak	(17.44)	0.00	(17.44)	(18.65)		(18.65)	-6.9%
Summer Average Mid - Peak	(4.91)	0.00	(4.91)	(5.36)		(5.36)	-9.2%
Winter Average Mid - Peak	(1.03)	0.00	(1.03)	(1.12)		(1.12)	-8.7%
Excess Energy Charge - $/kWh	12.22535	0.00000	12.22535	13.46026		13.46026	10.1%
TOU-8-S (Below 2kV)							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.02479	0.11232	0.13711	0.02398	0.08913	0.11311	-17.5%
Mid-peak	0.02479	0.06247	0.08726	0.02398	0.06033	0.08431	-3.4%
Off-Peak	0.02479	0.03820	0.06299	0.02398	0.04039	0.06437	2.2%
Winter Season							
Mid-peak	0.02479	0.06523	0.09002	0.02398	0.05839	0.08237	-8.5%
Off-Peak	0.02479	0.04386	0.06865	0.02398	0.04647	0.07045	2.6%
Customer Charge - $/month	609.75	0.00	609.75	582.25	0.00	582.25	-4.5%
Facilities Related Demand							
Demand Charge (Excess FRD) - $/kW	14.72	0.00	14.72	15.84	0.00	15.84	7.6%
Standby (CRC) - $/kW	8.41	0.00	8.41	8.45	0.00	8.45	0.5%
Time Related Demand Charge - $/kW							
Backup demand - Summer Season							
On-Peak	0.00	10.12	10.12	0.00	15.60	15.60	54.2%
Mid-Peak	0.00	2.93	2.93	0.00	2.65	2.65	-9.6%
Supplemental demand - Summer Season							
On-Peak	0.00	25.32	25.32	0.00	23.18	23.18	-8.5%
Mid-Peak	0.00	7.41	7.41	0.00	4.46	4.46	-39.8%
Power Factor Adjustment - $/kVA	0.51	0.00	0.51	0.55	0.00	0.55	7.8%

	January 2015 Rates			Proposed 2015 GRC Rates			
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
TOU-8-S-Rate A (Below 2kV)							
Energy Charge - $/kWh							
Summer Season							
On-Peak				0.02398	0.34868	0.37266	
Mid-peak				0.02398	0.09781	0.12179	
Off-Peak				0.02398	0.04039	0.06437	
Winter Season							
Mid-peak				0.02398	0.05839	0.08237	
Off-Peak				0.02398	0.04647	0.07045	
Customer Charge - $/month				582.25	0.00	582.25	
Facilities Related Demand							
Demand Charge (Excess FRD) - $/kW				15.84	0.00	15.84	
Standby (CRC) - $/kW				8.45	0.00	8.45	
Time Related Demand Charge - $/kW							
Backup demand - Summer Season							
On-Peak				0.00	15.60	15.60	
Mid-Peak				0.00	2.65	2.65	
Supplemental demand - Summer Season							
On-Peak				0.00	0.00	0.00	
Mid-Peak				0.00	0.00	0.00	
Power Factor Adjustment - $/kVA				0.55	0.00	0.55	
TOU-8-S (From 2 kV to 50 kV)							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.02578	0.11042	0.13620	0.02332	0.08687	0.11019	-19.1%
Mid-peak	0.02578	0.06150	0.08728	0.02332	0.05832	0.08164	-6.5%
Off-Peak	0.02578	0.03844	0.06422	0.02332	0.03904	0.06236	-2.9%
Winter Season							
Mid-peak	0.02578	0.06541	0.09119	0.02332	0.05649	0.07981	-12.5%
Off-Peak	0.02578	0.04431	0.07009	0.02332	0.04495	0.06827	-2.6%
Customer Charge - $/month	319.56	0.00	319.56	278.00	0.00	278.00	-13.0%
Facilities Related Demand							
Demand Charge (Excess FRD) - $/kW	14.09	0.00	14.09	16.10	0.00	16.10	14.3%
Standby (CRC) - $/kW	7.59	0.00	7.59	8.18	0.00	8.18	7.8%
Time Related Demand Charge - $/kW							
Backup demand - Summer Season							
On-Peak	0.00	9.99	9.99	0.00	15.86	15.86	58.8%
Mid-Peak	0.00	2.82	2.82	0.00	2.89	2.89	2.5%
Supplemental demand - Summer Season							
On-Peak	0.00	22.39	22.39	0.00	23.56	23.56	5.2%
Mid-Peak	0.00	6.45	6.45	0.00	4.45	4.45	-31.0%
Power Factor Adjustment - $/kVA	0.51	0.00	0.51	0.55	0.00	0.55	7.8%

	January 2015 Rates			Proposed 2015 GRC Rates			
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
TOU-8-S-Rate A (From 2 kV to 50 kV)							
Energy Charge - $/kWh							
Summer Season							
On-Peak				0.02332	0.35061	0.37393	
Mid-peak				0.02332	0.09458	0.11790	
Off-Peak				0.02332	0.03904	0.06236	
Winter Season							
Mid-peak				0.02332	0.05649	0.07981	
Off-Peak				0.02332	0.04495	0.06827	
Customer Charge - $/month				278.00	0.00	278.00	
Facilities Related Demand							
Demand Charge (Excess FRD) - $/kW				16.10	0.00	16.10	
Standby (CRC) - $/kW				8.18	0.00	8.18	
Time Related Demand Charge - $/kW							
Backup demand - Summer Season							
On-Peak				0.00	15.86	15.86	
Mid-Peak				0.00	2.89	2.89	
Supplemental demand - Summer Season							
On-Peak				0.00	0.00	0.00	
Mid-Peak				0.00	0.00	0.00	
Power Factor Adjustment - $/kVA				0.55	0.00	0.55	
TOU-8-S (Above 50 kV)							
Energy Charge - $/kWh							
Summer Season							
On-Peak	0.02233	0.09802	0.12035	0.02069	0.08110	0.10179	-15.4%
Mid-peak	0.02233	0.05493	0.07726	0.02069	0.05485	0.07554	-2.2%
Off-Peak	0.02233	0.03435	0.05668	0.02069	0.03698	0.05767	1.7%
Winter Season							
Mid-peak	0.02233	0.05819	0.08052	0.02069	0.05344	0.07413	-7.9%
Off-Peak	0.02233	0.04030	0.06263	0.02069	0.04269	0.06338	1.2%
Customer Charge - $/month	2,113.44	0.00	2,113.44	1,897.50	0.00	1,897.50	-10.2%
Facilities Related Demand							
Demand Charge (Excess FRD) - $/kW	5.75	0.00	5.75	6.69	0.00	6.69	16.3%
Standby (CRC) - $/kW	1.40	0.00	1.40	1.01	0.00	1.01	-27.9%
Time Related Demand Charge - $/kW							
Backup demand - Summer Season							
On-Peak	0.00	7.55	7.55	0.00	11.50	11.50	52.3%
Mid-Peak	0.00	1.93	1.93	0.00	1.65	1.65	-14.5%
Supplemental demand - Summer Season							
On-Peak	0.00	21.12	21.12	0.00	24.37	24.37	15.4%
Mid-Peak	0.00	5.54	5.54	0.00	4.38	4.38	-20.9%
Power Factor Adjustment - $/kVA	0.34	0.00	0.34	0.47	0.00	0.47	38.2%
Voltage Discount, 220 kV and above							
Facilities Related Demand (Excess FRD) - $k/W	(2.18)	0.00	(2.18)	(3.12)	0.00	(3.12)	-43.1%
Time-Related Demand - $/kW							
Summer	0.00	(0.09)	(0.09)	0.00	(0.15)	(0.15)	-66.7%
Energy - $/kWh	0.00000	(0.00051)	(0.00051)	0.00000	(0.00048)	(0.00048)	5.9%
Standby (CRC) - $/kW	(0.84)	0.00	(0.84)	(0.45)	0.00	(0.45)	46.4%

	January 2015 Rates			Proposed 2015 GRC Rates			
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
TOU-8-S-Rate A (Above 50 kV)							
Energy Charge - $/kWh							
Summer Season							
On-Peak				0.02069	0.34049	0.36118	
Mid-peak				0.02069	0.08686	0.10755	
Off-Peak				0.02069	0.03698	0.05767	
Winter Season							
Mid-peak				0.02069	0.05344	0.07413	
Off-Peak				0.02069	0.04269	0.06338	
Customer Charge - $/month				1,897.50	0.00	1,897.50	
Facilities Related Demand							
Demand Charge (Excess FRD) - $/kW				6.69	0.00	6.69	
Standby (CRC) - $/kW				1.01	0.00	1.01	
Time Related Demand Charge - $/kW							
Backup demand - Summer Season							
On-Peak				0.00	11.50	11.50	
Mid-Peak				0.00	1.65	1.65	
Supplemental demand - Summer Season							
On-Peak				0.00	0.00	0.00	
Mid-Peak				0.00	0.00	0.00	
Power Factor Adjustment - $/kVA				0.47	0.00	0.47	
Voltage Discount, 220 kV and above							
Facilities Related Demand (Excess FRD) - $k/W				(3.12)	0.00	(3.12)	
Time-Related Demand - $/kW							
Summer				0.00	0.00	0.00	
Energy - $/kWh				0.00000	(0.00068)	(0.00068)	
Standby (CRC) - $/kW				(0.45)	0.00	(0.45)	
Schedule-S (Less than 500 kW)							
Energy Charge - $/kWh/Meter/Month - see (OAT)							
Customer Charge - $/Meter/Month - see (OAT)							
Standby (CRC) - $kW							
TOU-GS-2 (Rate B)	8.41	0.00	8.41	8.45	0.00	8.45	0.5%
Voltage Discount, Capacity Reservation Demand - $/kW							
From 2 kV to 50 kV	(0.10)	0.00	(0.10)	(0.12)	0.00	(0.12)	-20.0%
51 kV to 219 kV	(3.35)	0.00	(3.35)	(3.96)	0.00	(3.96)	-18.2%
220 kV and Above	(5.78)	0.00	(5.78)	(5.82)	0.00	(5.82)	-0.7%
TOU-GS-3 (Rate B)	8.41	0.00	8.41	8.45	0.00	8.45	0.5%
Voltage Discount, Capacity Reservation Demand - $/kW							
From 2 kV to 50 kV	(0.09)	0.00	(0.09)	(0.10)	0.00	(0.10)	-11.1%
51 kV to 219 kV	(3.05)	0.00	(3.05)	(3.44)	0.00	(3.44)	-12.8%
220 kV and Above	(5.78)	0.00	(5.78)	(5.82)	0.00	(5.82)	-0.7%
GS-2	8.41	0.00	8.41	8.45	0.00	8.45	0.5%
Voltage Discount, Capacity Reservation Demand - $/kW							
From 2 kV to 50 kV	(0.10)	0.00	(0.10)	(0.12)	0.00	(0.12)	-20.0%
51 kV to 219 kV	(3.35)	0.00	(3.35)	(3.96)	0.00	(3.96)	-18.2%
220 kV and Above	(5.78)	0.00	(5.78)	(5.82)	0.00	(5.82)	-0.7%

Facilities Related Demand Charge - see OAT
Demand Charge - $kW applicable to metered maximum kW demand in excess Standby

Generation Time-related demand charge - see OAT

Power Factor Adjustment Charge - see OAT

	January 2015 Rates			Proposed 2015 GRC Rates			
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
TOU-8-S-RTP							
Energy Charge - $/kWh							
Below 2 kV	0.02479	Variable*	Variable*	0.02398	Variable*	Variable*	
From 2 kV to 50 kV	0.02578	Variable*	Variable*	0.02332	Variable*	Variable*	
above 50 kV	0.02233	Variable*	Variable*	0.02069	Variable*	Variable*	
Customer Charge - $/month							
Below 2 kV	609.75	0.00	609.75	582.25	0.00	582.25	-4.5%
From 2 kV to 50 kV	319.56	0.00	319.56	278.00	0.00	278.00	-13.0%
above 50 kV	2,113.44	0.00	2,113.44	1,897.50	0.00	1,897.50	-10.2%
Facilities Related Demand Charge - $/kW							
Demand Charge (Excess FRD) - $/kW							
Below 2 kV	14.72	0.00	14.72	15.84	0.00	15.84	7.6%
From 2 kV to 50 kV	14.09	0.00	14.09	16.10	0.00	16.10	14.3%
above 50 kV	5.75	0.00	5.75	6.69	0.00	6.69	16.3%
Standby (CRC) - $/kW							
Below 2 kV	8.41	0.00	8.41	8.45	0.00	8.45	0.5%
From 2 kV to 50 kV	7.59	0.00	7.59	8.18	0.00	8.18	7.8%
above 50 kV	1.40	0.00	1.40	1.01	0.00	1.01	
Voltage Discount, 220 kV and above							
Energy - $/kWh	0.00000	(0.00073)	(0.00073)	0.00000	(0.00030)	(0.00030)	58.9%
Capacity Reservation Demand (CRC) - $/kW	(0.84)	0.00	(0.84)	(0.45)	0.00	(0.45)	46.4%
Facilities Related Demand, excess of CRC - $/kW	(2.18)	0.00	(2.18)	(3.12)	0.00	(3.12)	-43.1%
Power Factor Adjustment - $/kVA							
Greater than 50 kV	0.34	0.00	0.34	0.47	0.00	0.47	38.2%
50 kV or less	0.51	0.00	0.51	0.55	0.00	0.55	7.8%
Optional CPP rider < 200 kW							
CPP Event Energy Charge - $/kWh							
GS-2	0.00000	1.37453	1.37453	0.00000	1.37453	1.37453	0.00%
Summer Non-Event Demand Credit - $/kW							
GS-2	0.00	(10.09)	(10.09)	0.00	(10.09)	(10.09)	0.00%
Default CPP rider > 200 kW							
TOU-GS-3							
2 p.m. to 6 p.m CPP Event Energy Charge - $/kWh	0.00000	1.37453	1.37453	0.00000	1.37453	1.37453	0.00%
Summer On Peak Demand Credit - $/kW	0.00	(11.44)	(11.44)	0.00000	(11.44)	(11.44)	0.00%
TOU-8-SEC							
2 p.m. to 6 p.m CPP Event Energy Charge - $/kWh	0.00000	1.37453	1.37453	0.00000	1.37453	1.37453	0.00%
Summer On Peak Demand Credit - $/kW	0.00	(11.93)	(11.93)	0.00000	(11.93)	(11.93)	0.00%
TOU-8-PRI							
2 p.m. to 6 p.m CPP Event Energy Charge - $/kWh	0.00000	1.34519	1.34519	0.00000	1.34519	1.34519	0.00%
Summer On Peak Demand Credit - $/kW	0.00	(11.82)	(11.82)	0.00000	(11.82)	(11.82)	0.00%
TOU-8-SUB							
2 p.m. to 6 p.m CPP Event Energy Charge - $/kWh	0.00000	1.29359	1.29359	0.00000	1.29359	1.29359	0.00%
Summer On Peak Demand Credit - $/kW	0.00	(11.58)	(11.58)	0.00000	(11.58)	(11.58)	0.00%

Appendix C

Procedures for Modification and Phase-In Of Standby Billing Determinants

Notwithstanding any provision set forth in the Procedure for Performing a Confirmation Review of Standby Billing Determinants, below, SCE or a customer may initiate a review of the Standby Demand (SD) or Supplemental Contract Capacity (SCC) (collectively, Billing Determinants) at any time to more appropriately reflect a customer's operating condition(s), provided, however, that any revised Billing Determinants once established shall be effective prospectively for a minimum of 12 months. Any change to the Billing Determinants shall become effective immediately and be applied prospectively on the customer's next meter read date.

The provisions set forth in the Procedure for Performing a Confirmation Review of Standby Billing Determinants and the Procedure for Phasing-In Standby Billing Determinants are intended to govern the initial application of the Standby Algorithm for Existing, Transition, and New Standby Customers for only the period between initial implementation of this Settlement Agreement to the date on which the rates implementing SCE's 2018 GRC Phase 2 are effective. Customers may avail themselves of these procedures (including the phase-in of any changes resulting from the Confirmation Review) only to the extent that the phase-in occurs during the same period.

Initial Implementation of the Algorithm for Standby Customers

Existing Standby Customers:

The status of each Existing Standby Customer will be established through the following procedure: The Algorithm will use the most recent 36 months of recorded data (or the longest period of relevant data available, but not less than 14 months of such data) to calculate the SCC and SD. Customers whose Algorithm-calculated SD or SCC are within a range of plus or minus 10% of the then-current value will maintain the then-current Billing Determinants, unless the customer requests a revision consistent with the Algorithm-calculated SD or SCC. Customers whose Algorithm-calculated SD or SCC are outside of the range of plus or minus 10% of the current value will receive from SCE an initial bill impact analysis comparing then-current Billing Determinants with the Algorithm-calculated Billing Determinants (new Billing Determinants) using the same rates. Existing Standby Customers will have their new Billing Determinants phased-in, as described in Section B, the Procedure For Phasing In Standby Billing Determinants, on the Standby Implementation Date (expected to be approximately three months after the implementation of a final decision in this proceeding). SCE will, at the customer's request, consult with the customer to perform a Confirmation Review of the customer's specific site information and operating conditions to verify that any modification of the customer's SCC and SD comports with customer operations, as described in Section A, the Procedure for Performing a Confirmation Review of Standby Billing Determinants (below). Customers will have a period of 12 months after the Standby Implementation Date to request a Confirmation Review.

Transition Standby Customers:

Transition Standby Customers will maintain their then-current Billing Determinants until a minimum of 14 months of interval data have been recorded. SCE will then use the Algorithm to calculate the SD and SCC, and will, if the Customers' Algorithm-calculated SD or SCC is outside of the range of plus or minus 10% of the current value, provide an initial bill impact analysis as described above. Customers will have their new Billing Determinants phased-in, as described in Section B, approximately three months after receipt of their initial bill impact analysis, on the Secondary Standby Implementation Date. SCE will, at the customer's request, perform a Confirmation Review, as described in Section A. Customers will have a period of 12 months after the Secondary Standby Implementation Date to request a Confirmation Review.

New Standby Customers:

New Standby Customers will not have their initial Billing Determinants calculated by the Algorithm. SCE—alone or in cooperation with the customer—will rely on a description of the generating unit(s), including, but not limited to, total capacity; technology and purpose (*e.g.*, CHP or other); number of units operating during normal conditions; and scheduled maintenance cycle, to develop a good faith estimate of the appropriate SD and SCC values. This initial determination for New Standby Customers, before 14 months of data is available, is not subject to revision. Once a minimum of 14 months of data is collected, the Algorithm will be applied to New Standby Customers' interval data, subject to the Confirmation Review and dispute resolution processes detailed below. SCE will use the Algorithm to calculate the SD and SCC, and will, if the Customers' Algorithm-calculated SD or SCC is outside of the range of plus or minus 10% of the current value, provide an initial bill impact analysis as described above. Customers will have their new Billing

Determinants phased-in, as described in Section B, approximately three months after receipt of their initial bill impact analysis, on the Secondary Standby Implementation Date. SCE will, at the customer's request, perform a Confirmation Review, as described in Section A. Customers will have a period of 12 months after the Secondary Standby Implementation Date to request a Confirmation Review.

SECTION A: Procedure for Performing a Confirmation Review of Standby Billing Determinants

The Confirmation Review will be performed at the request of the customer, or can be initiated by SCE when the SD or SCC, as determined by the Algorithm, results in an expected bill impact greater than or equal to 10%,[1] relative to bills reflecting the standby billing determinants calculated under the current methodology. For both bill impact calculations, the same set of rates will be used in order to isolate the impact to changes resulting from application of the Algorithm. The Confirmation Review will be conducted to establish the appropriate SD and/or SCC including, if necessary, a series of steps to examine the reason(s) for any material difference. The Confirmation Review process will be limited to disputes arising from the initial implementation of the Algorithm-determined Standby Billing Determinants. Consistent with Paragraph 4(H)(2) of this Settlement Agreement, no party availing itself of the Confirmation Review shall seek to modify the Algorithm set forth in this Settlement Agreement, including Appendix D. Customers will have a period of 12 months after the Standby Implementation Date, or Secondary Standby Implementation Date where applicable, to request a Confirmation Review. If the Confirmation Review results in a set of Billing Determinants that differ from those implemented on the Standby Implementation Date, SCE will perform a rebill, dating back to the Standby Implementation Date, or Secondary Standby Implementation Date where applicable, of the customer's standby service using the Billing Determinants established as a result of the Confirmation Review process.

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[1] The SD or SCC will not be changed for an existing account in the event that the Algorithm calculated value is within a range of plus or minus 10% of the current value, unless at the request of the customer.

1. **<u>Confirmation Review for Existing Standby Customers</u>**

    1.1. SCE will review specific events and/or trends, within the customer's 15-minute interval data, over the past 36 months to evaluate the customer's operating condition. In the event 36 months of data are not available, SCE will evaluate a minimum of 14 months of available data. If 14 months of data are not available for an Existing Standby Customer, the customer is considered a Transition Standby Customer. More information on treatment for Transition Standby Customers is included in Section 2 of this Appendix.

    1.2. SCE will obtain from the customer a specific description of the generating unit(s), including, but not limited to, the following items: Total nameplate capacity; technology and design purpose, CHP or other; number of units operating during normal conditions; and scheduled maintenance cycle.

    1.3. After gathering and analyzing the data from steps 1.1 and 1.2, SCE will consult with the customer to validate the operating condition(s) reflected by the review of meter data and site-specific information, and determine whether determination of new Billing Determinant(s) is warranted. The customer and SCE will have 45 Calendar Day(s) to resolve this step and establish mutually agreed-upon Standby Billing Determinants. If no resolution can be reached, and SCE and the customer do not mutually agree to extend the deadline in this step, the Dispute will be handled in accordance with Section C.

    1.4. If the results of the Confirmation Review differ from the Algorithm-calculated SD or SCC, then SCE will perform a rebill, dating back to the Standby Implementation Date, of the customer's standby service using the Billing Determinants established as a result of the Confirmation Review process.

2. **<u>Confirmation Review for New Standby Customers and Transition Standby Customers</u>**

    2.1. SCE will review specific events and/or trends, within the customer's 15-minute interval data, for as many months as are available for the customer at the time of the review (minimum of 14 months of data).

    2.2. SCE will obtain from the customer a specific description of the generating unit(s), to include but not be limited to the following items: Total capacity; technology and purpose, CHP or other; number of units operating during normal conditions; and scheduled maintenance cycle.

2.3. After gathering and analyzing the data from Steps 2.1 and 2.2, SCE will consult with the customer to validate the operating condition(s) reflected by the review of meter data and site- specific information. The customer and SCE will have 45 Calendar Day(s) to resolve this step and establish mutually agreed-upon Standby Billing Determinants. If no resolution can be reached, and SCE and the customer do not mutually agree to extend the deadline in this step, the Dispute will be handled in accordance with Section C.

2.4. In the event a Transition Standby Customer's Billing Determinants established as the result of the Confirmation Review process differ from the SD and SCC initially implemented by SCE on the Secondary Standby Implementation Date, SCE will perform a rebill of the customer's standby service, dating back to the Secondary Standby Implementation Date using the Billing Determinants established as a result of the Confirmation Review process. The rebill will be limited to disputes arising in the Confirmation Review process about the Billing Determinants implemented on the Secondary Standby Implementation Date. Customers will have a period of 12 months after the Secondary Standby Implementation Date to request that SCE perform a Confirmation Review.

2.5. In the event a New Standby Customer's Billing Determinants established as a result of the Confirmation Review process differ from the SD and SCC implemented on the Secondary Standby Implementation Date, SCE will perform a rebill dating back to the Secondary Implementation Date using the Billing Determinants established as a result of the Confirmation Review process. The rebill will be limited to disputes arising in the Confirmation Review process about the Billing Determinants implemented on the Secondary Standby Implementation Date. Customers will have a period of 12 months after the Secondary Standby Implementation Date to request that SCE perform a Confirmation Review.

SECTION B: Procedure For Phasing In Standby Billing Determinants for Standby Customers

3. New Billing Determinants, as calculated by the Algorithm or Confirmation Review Process, will be phased-in, at the option of the customer, for Existing, Transition, and New Standby Customers whose current Billing Determinants are not within plus or minus 10% of the new Billing Determinants. These new Billing Determinants will be phased-in for customers

based on the results of an initial bill impact analysis comparing the current Billing Determinants with the Algorithm-calculated Billing Determinants using the same rates. If the initial bill impact analysis yields an increase of 10% or more, SCE will run additional iterations using adjusted Billing Determinants to determine the appropriate phase-in process.

3.1. **"Category 1" Customers**

Customers are considered "Category 1" if the bill impact analysis results in an increase of 10% or less. Category 1 customers will have their Billing Determinants reset to the Billing Determinants calculated by the Algorithm or Confirmation Review, as appropriate, and shall become effective immediately and applied on the customers' next meter read date.

3.2. **"Category 2" Customers**

For customers whose initial bill impact analysis results in an increase of greater than 10%, a second bill impact analysis will be performed using adjusted Billing Determinants that are set mid-way between the customer' s current values and the Algorithm's (or Confirmation Review) determined values (*i.e.*, 50% of the determined adjustment). The following example illustrates how this adjustment will be applied. Assume the customer's current Standby Demand is 1,100 kW and the Algorithm calls for a downward adjustment in the Standby Demand of 500 kW (1,100 kW to 600 kW), which results in an annual bill increase of greater than 10%. SCE will perform a second bill impact analysis assuming a mid-point adjustment of the Standby Demand of 250 kW (50% of 500 kW) to a value of 850 kW.

Customers are considered "Category 2" if the second iteration bill impact analysis results in an increase of less than 10%. Category 2 customers will have their Billing Determinants set at the 50% level immediately, with any remaining movement based on Algorithm runs (or Confirmation Review) to be determined in the 2018 GRC Phase 2 (subject to the provisions of 3.5 set forth below).

3.3. **"Category 3" Customers**

Customers are considered "Category 3" if the second iteration bill impact analysis results in an increase of greater than 10%. Category 3 customers will have their Billing Determinants phased-in equally over three years, beginning three months after implementation of 2015 GRC Phase 2 rate changes, in 1/3 annual increments to the 50%

level, with any remaining movement based on Algorithm runs to be determined in the 2018 GRC Phase 2 (subject to the provisions of 3.5 set forth below).

3.4. For both Category #2 and Category #3 customers, a final phase-in to the Algorithm (or Confirmation Review) determined Standby Demand shall be determined as part of the 2018 GRC Phase 2 proceeding.

3.5. The Billing Determinants, set either at the initial level or the 50% adjusted level, can be reviewed and reset, within the attrition years, if the service account experiences a change in operating condition. A review of the Billing Determinants can be initiated by either the customer of record or SCE.

SECTION C: Dispute Resolution

4. Dispute Resolution. If a customer and SCE (individually referred to as "Party" and collectively "the Parties") are unable to establish mutually agreed-upon Billing Determinants through the Confirmation Review process, the new Billing Determinants shall be resolved according to the following procedures:

4.1. The dispute shall be documented with a written notice ("notice") sent by the customer to SCE containing the relevant known facts pertaining to the dispute, the specific dispute and the relief sought, and express notice that the customer is invoking the procedures under this Special Condition. The notice shall be sent to StandbyDemandDepartingLoad@sce.com and 6042 N. Irwindale Ave. Irwindale, CA 91702. The other Party (SCE) shall acknowledge receipt of the notice within five (5) Calendar Days of its receipt.

4.2. Upon the customer notifying SCE of the dispute, each Party must designate a representative with the authority to make decisions for its respective Party to review the dispute within seven (7) Calendar Days. In addition, upon receipt of the notice, SCE shall provide the customer with sufficient back-up information and analysis regarding the determination of the customer's Standby Demand and SCC within twenty-one (21) Calendar Days.

4.3. The Parties may by mutual agreement make a written request for mediation to the ADR Coordinator in the Commission's ALJ Division. The request may be submitted by electronic mail to adr_program@cpuc.ca.gov.

4.4. At any time, the customer may file a formal complaint before the Commission pursuant to California PUC section 1702 and Article 4 of the Commission's Rules of Practice and Procedure.

4.5. Pending resolution of any dispute under this Section, the Parties shall proceed diligently with the performance of their respective obligations.

4.6. In the event the customer's Billing Determinants established as the result of the dispute resolution process differ from the SD and SCC initially implemented by SCE, a rebilling of customer's standby service shall be performed for the period beginning with the first meter read date on which the initial SCE-determined Billing Determinants were effective.

Appendix D

Algorithm Description Including Excerpts from Exhibit SCE-08

This appendix contains portions of SCE's testimony in Exhibit SCE-08 that were unmodified by the Settlement Agreement and the description below is to be considered together with—and not as contradicting—the remainder of the Settlement Agreement (inclusive of all Appendix C).

The proposed algorithm is based on the principle that SCE provides back-up service only during periods when the generator would otherwise be expected to be operational (i.e., times when the generator experiences a forced or unscheduled outage). Under this basic principle, the maximum value of demand for back-up service is necessarily set by the required peak demand when the unit experiences a forced or unscheduled outage. Thus, back-up service is not provided during periods when the generator would not otherwise be expected to be running, such as during startup, shutdown, scheduled maintenance outages, or (for solar generation) at night. Regularly served base load that is provided by SCE when the generator is operating, is also not considered back-up service. These types of regular service represent supplemental load.

The proposed algorithm will take into account the normal operating "pattern" of the generating unit, and identifies the daily maximum Distribution facilities related demand that is most frequently served by SCE. The new method is based on the fact that peak non-time-related demand is the key cost driver associated with Distribution facilities costs. Determining the daily maximum peak demand most frequently served, will allow SCE to better identify the required level of supplemental service and more effectively set rates on the basis of cost causation. By "pattern," SCE focuses on the mode of the daily maximum peak demand, where the mode is defined as the value that occurs most frequently. Therefore the mode can be considered the value that is most typical of all the values. The Standby Demand is then derived from the difference between the overall annual peak demand and the supplemental demand.[1] The new algorithm is discussed in more detail below.

The proposed algorithm will be applied to processes performed outside of the billing system. Once the algorithm identifies supplemental versus back-up load, SCE will render a bill using the existing billing algorithm for both non-Net Generator Output (non-NGO) metered accounts, and customers with Net Generator Output metering. This proposed algorithm resulted from fruitful discussions leading up to the filing of this Supplemental Testimony with several parties from the last GRC Phase 2 who are signatories to SCE's 2012 GRC Phase Medium and

1 This term is defined in the Settlement as Supplemental Contract Capacity.

Large Power Settlement Agreement and are knowledgeable on standby rate design issues. The proposed algorithm was used to update the revenue allocations presented in Exhibit SCE-03 and for the rate designs in this Exhibit SCE-04.

The proposed algorithm is applicable to fully resourced and partially resourced accounts. An account is fully resourced when the generating unit is able to meet all of its onsite energy requirements throughout the course of a 24-hour period. Partially resourced sites comprise the balance of the standby customers, where the generating unit provides only a portion of the energy requirements. If the account is a fully resourced combined heat and power site, or incorporates any other behind-the-meter technology intended to serve onsite process loads, the algorithm bases the Standby Demand and Supplemental Contract Capacity determinations on the mode of the daily maximum peak demand as discussed above. In addition, for these fully resourced accounts, the total available generating capacity at the site is taken into consideration to ensure the Reserve Capacity value is not less than the available onsite generating capacity. Customers will continue to be able to elect a Reserve Capacity less than the value of the available onsite generating capacity. For partially resourced accounts, the Standby Demand and Supplemental Contract Capacity determinations are based on the mode of the Daily Maximum peak demand as discussed above, with no further limits applied; provided, however, that after the Algorithm has preliminarily established the Supplemental Contract Capacity, the customer may elect a Standby Demand (*i.e.*, Reserve Capacity) up to the nameplate capacity of the available onsite generating unit(s).

For new or existing accounts with sufficient data, SCE will produce a Peak Day table to identify the daily maximum peak demands for each day over the period for which data is available. Therefore if 36 months of data are available, the algorithm will identify approximately 1,095 daily maximum peak demand values, from the 105,120 fifteen-minute interval demands available in metered data. The values in the Peak Day table are then rounded in order to conduct a meaningful frequency distribution, or mode, analysis. The values are rounded up or down to the nearest significant digit: either, tens, hundreds, or thousands of kW. For example, a value of 127 kW is rounded to 130 kW; a value of 2,157 kW is rounded to 2,200 kW and; a value of 101,136 kW is rounded to 101,000 kW. Rounding is used to account for the large customer size range present in the standby classes. The algorithm then determines the mode by identifying the most frequently occurring Daily Maximum peak demand from the set of rounded values. The value returned from this step represents the Supplemental Contract Capacity, or the maximum level for supplemental demand. The Reserve Capacity is then determined by taking the difference of the overall peak demand, over the period for which data is available, and the Supplemental Contract Capacity. The Reserve Capacity is always greater than zero and never greater than the generator name plate capacity.