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, and Design Rates.	A.17-06-030 (Filed June 30, 2017)

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

FADIA R. KHOURY
RUSSELL A. ARCHER

Attorneys for
SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770
Telephone: (626) 302-2865
E-mail: Russell.Archer@sce.com

Dated: **August 3, 2018**

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

TABLE OF CONTENTS

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

TABLE OF CONTENTS (CONTINUED)

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, and Design Rates.	A.17-06-030 (Filed June 30, 2017)

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

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 Settling Parties,[1] files this motion requesting that the Commission find reasonable and adopt the "Medium and Large Power 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 that resolves the issues surrounding default and optional rates for the Medium and Large Power (*i.e.*, Commercial & Industrial (C&I)) rate group customers. These settled issues include:

[1] The Settling Parties or Parties are SCE; California Large Energy Consumers Association (CLECA); Energy Users Forum (EUF); Solar Energy Industries Association (SEIA); California Manufacturers & Technology Association (CMTA); California Solar & Storage Association (CALSSA); Federal Executive Agencies (FEA); the Energy Producers and Users Coalition (EPUC); and Direct Access Customer Coalition (DACC). Pursuant to Rule 1.8(d), SCE has been authorized to file this motion on behalf of the Settling Parties.

- Replacement of SCE's existing Option B with Option D (in Base Rate Medium and Large Power rate groups);
- Replacement of SCE's existing Options A and R with Option E (in Base Rate Medium and Large Power rate groups), which includes updates to eligibility requirements;
- Agreements regarding future actions for energy storage-specific rate designs and Real-Time Pricing options;
- EV-specific rate options; and
- Standby rate design options.

The Settlement Agreement embodies both certain uncontested proposals made by SCE in its application and compromise positions that have resulted from intensive good-faith settlement negotiations in what has been deemed settlement "Track No. 4" of this proceeding. The resulting settlement embodies a carefully-struck compromise between Settling Parties that represent disparate customer interests. The Settlement Agreement includes:

- Basic provisions that adhere to marginal cost principles (especially with the new default rates' focus for the first time on implementation of time-differentiation of distribution costs to recover costs through a significantly higher percentage of time-related coincident peak costs through coincident (*i.e.*, non-Facilities-Related Demand) charges);
- Provides rate options that afford meaningful choice to customers (with its inclusion of optional rates) that are designed to meet the need of Distributed Energy Resources (DER) customers including energy storage customers and electric vehicle (EV)-owning customers); and
- Lays a strong foundation for future rate design implementation that should include economic price signals that adhere more closely to market costs and recognize changing grid and technology conditions.

Section II of this Motion provides the regulatory background related to this proceeding. Section III describes in general the positions advocated by the Parties 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

A. Background of this Proceeding

This proceeding was initiated by the filing of SCE's application on June 30, 2017, along with service of SCE's prepared direct testimony regarding marginal costs, revenue allocation and rate design. On November 22, 2017, the Assigned Commissioner and Assigned Administrative Law Judge issued a Scoping Memo and Ruling following a November 2, 2017 prehearing conference. ORA served its initial testimony on February 16, 2018. On March 23, 2018, FEA, CLECA, EPUC, DACC, SEIA and CALSSA submitted prepared testimony regarding Medium and Large Power rate group rate design issues that are addressed by this Settlement Agreement.

The Settling Parties represent a broad spectrum of customer interests, as indicated in Paragraph 1 of the Settlement Agreement. Each Settling Party represents customers or groups of customers who are affected by, and have an interest in, the resolution of the Medium and Large Power rate group rate design issues that are addressed by this Settlement Agreement.

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 April 6, 2018. Continuing settlement discussions occurred among the parties after April 6, 2018. Specific to this Settlement Agreement, the Settling Parties commenced "Track No. 4" settlement discussions on June 4, 2018. This Motion with its accompanying Settlement Agreement follows.

III.

SUMMARY OF POSITIONS AND SETTLEMENT

The Settlement Agreement resolves issues related to Medium and Large Power rate group rate design issues. The provisions of the Settlement Agreement are summarized below and in a comparison exhibit, Appendix A to the Settlement Agreement, which provides a comparison of party positions related to the relevant issues and the manner in which these issues have been resolved by the Settlement Agreement.[2]

The major Medium and Large Power rate group rate design issues addressed in testimony were the following:

- The replacement of Option B with New Option D as the new Base Rate design for TOU-GS-2 and TOU-GS-3 (*i.e.*, Medium Power rate group) and TOU-8 (*i.e.*, Large Power rate group) customers;
    - The appropriate design of the new Option D rates;
- The replacement of Options A and R with New Option E as the optional rate design for TOU-GS-2 and TOU-GS-3 (*i.e.*, Medium Power rate group) and TOU-8 (*i.e.*, Large Power rate group) customers;
    - The appropriate design of the new Option E rates;
    - Eligibility requirements for Option E for customers in the TOU-8 rate classes;
    - Potential energy storage-specific rates;
- Real-Time Pricing, Standby, and Reliability Back-Up Service rates;
- Electric Vehicle-specific rates; and,
- Demand Response-specific rates.

The Settlement Agreement resolves these issues. Among other things, the Settlement Agreement provides the means of establishing average rates by rate class and schedule when this Agreement is first implemented and for the term of the Agreement. Illustrative average rates for each rate class based on the Settlement Agreement are provided in Appendix B to the Settlement Agreement.

A. <u>Demand Charges (General Overview)</u>

Demand Charges consist of Time-Related Demand (TRD) and Facilities-Related Demand (FRD) charges. TRD Charges may be differentiated by summer and winter seasons and by time-of-use (TOU) periods. FRD charges are not differentiated by season or TOU periods. Overall, the settled rates shift

---

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

more cost recovery from FRD charges to TRD (and Energy) Charges.

1. <u>TRD Charges</u>

The Settlement Agreement's Option D (*i.e.*, the Base Rate) for each class will continue to collect most generation capacity costs via TRD Charges. To reflect the impact of system ramping needs and the need for flexible capacity on a year-round basis, generation capacity TRD charges will apply in the winter mid-peak period (in addition to their traditional treatment in the summer on-peak period). Additionally, as a first step to introducing time-differentiation in distribution rates, the Settlement Agreement establishes new distribution TRD Charges in both the summer on-peak and winter mid-peak periods.

The Settlement Agreement's Option E (*i.e.*, the optional rate) offers a much lower generation TRD Charge compared to Option D and has no distribution TRD Charge. This is consistent with current Options A and R (which Option E replace) that have no TRD Charges. More details are provided in the rate-specific discussions below, and in the summary tables in Section IV.

2. <u>FRD Charges</u>

Both Options D and E include a non-coincident FRD Charge (as do the rates they replace). However, Options D and E (across all rate classes) recover a much lower percentage of distribution revenue through FRD charges as compared to the rates they replace. More details are provided in the rate-specific discussions below, and in the summary tables in Section IV.

B. <u>Base and Optional Rates and Rate Design (Non-Standby)</u>

1. <u>Option D Base Rate – Eligibility Requirements and Rate Design</u>

a) <u>Option D Eligibility for TOU-GS-3 and TOU GS-3</u>

SCE proposed to maintain the current eligibility that applies to Option B for the new Option D (*i.e.*, C&I customers with demands above 20 kW up to 500 kW). No party addressed that proposal and the Settlement Agreement adopts SCE's uncontested proposal.

b) <u>Option D Rate Design for TOU-GS-2 and TOU-GS-3</u>

SCE proposed:

- New Option D should continue to include a Customer Charge of approximately $110/month (TOU-GS-2) and $266/month (TOU-GS-3), adjusted to recover a portion of the final line transformer (FLT) costs in the grid distribution demand charge;
- Generation Energy should be recovered via TOU Energy Charges;
- Generation Capacity should be recovered through a combination of TOU Energy Charges and TRD Charges;
- Distribution Peak costs should be recovered through a combination of TOU cent-per-kWh Energy Charges (approximately 50 percent) with the balance recovered through a new TRD Charge and FRD Charge; and
- Distribution Grid costs be recovered through an FRD Charge.

SEIA strongly supported the direction of SCE's proposed changes (*i.e.*, more time-dependent allocation of distribution costs), but disagreed that coincident-peak-related distribution costs should be recovered via non-coincident demand charges. SEIA proposed its own Option D rates using the peak load risk factor (PLRF) proposal from the Office of Ratepayer Advocates' (ORA) testimony.[3] SEIA's proposal further functionalized peak marginal distribution costs into coincident peak and non-coincident peak (and also included a non-peak component). SEIA's proposal would result in a significant reduction in non-coincident demand charges.

Ultimately, the Settlement Agreement adopts a compromise rate design as follows:

- Updated TOU periods per D.18-07-006.
- A Customer Charge of $125.25/month (TOU-GS-2) and $307/month (TOU-GS-3).
- For distribution, using a settled distribution demand marginal cost (DDMC) value: (1) a summer on-peak TRD Charge that recovers summer

[3] ORA Testimony on Southern California Edison Company's 2018 GRC Phase 2, Chapter 4, p. 4-22.

on-, mid- and five percent of off-peak capacity costs; (2) a winter mid-peak TRD charge that recovers all winter peak capacity costs; (3) flat cent-per-kWh Energy Charges to recover 95 percent of summer off-peak capacity costs across all TOU periods; and (4) the use of an FRD Charge to recover Grid-related costs.

- For generation, peak and capacity costs are allocated to TOU periods using the loss of load expectation (LOLE) methodology; summer on-peak and winter capacity costs are recovered via the summer on-peak and winter mid-peak TRD Charges, while summer mid- and off-peak capacity costs are included in summer on- and mid-peak energy charges; and, generation energy costs are recovered via volumetric TOU Energy Charges.

c) Option D Eligibility for TOU-8

SCE proposed to maintain the current eligibility that applies to Option B for the new Option D (*i.e.*, C&I customers with demands over 500 kW but excluding certain large water pumping and agricultural customers). No party addressed that issue and the Settlement Agreement adopts SCE's uncontested proposal.

d) Option D Rate Design for TOU-8

SCE proposed that new Option D should include:

- Customer Charge established at full marginal-cost-based levels adjusted to recover a portion of the FLT costs in the grid distribution demand charge;
- Generation Energy should be recovered via TOU Energy Charges;
- Generation Capacity should be recovered through a combination of TOU Energy Charges and TRD Charges;
- Distribution Peak costs should be recovered through a combination of TOU cent-per-kWh Energy Charges (approximately 50 percent) with the balance recovered through new TRD and FRD Charges; and

- Distribution Grid costs be recovered through an FRD Charge.

CLECA proposed recovering generation capacity costs in TRD Charges with mitigation of bill impacts through some recovery (less than SCE's proposal) in TOU Energy Charges. It opposed SCE's proposal to recover some of the coincident distribution capacity costs via distribution Energy Charges and some of the non-cost-based TOU energy smoothing SCE proposed for peak distribution. CLECA's alternate proposal included: (1) using CLECA's uncapped revenue allocation and (2) recovery of all distribution capacity costs in TRD and FRD Charges (*e.g.*, no recovery in Energy Charges). Similar to CLECA, EPUC opposed SCE's proposal to recover 50 percent of distribution peak capacity via Energy Charges and proposed to collect all capacity costs via capacity (*i.e.*, demand) charges. FEA concurred.

SEIA strongly supported the direction of SCE's proposed changes (*i.e.*, more time-dependent allocation of distribution costs), but disagreed that coincident-peak-related distribution costs should be recovered via non-coincident demand charges. SEIA proposed its own Option D rates using ORA's PLRF proposal, which functionalized more marginal distribution costs into the coincident peak portion of the rates. SEIA's proposal would result in a significant reduction in non-coincident demand charges.

Ultimately, the Settlement Agreement adopts a compromise rate design as follows for TOU-8-Sec and TOU-8-Pri:

- Updated TOU periods per D.18-07-006.
- Customer Charge as set forth in Appendix B of the Settlement Agreement.
- For distribution, using a settled DDMC value: (1) a summer on-peak TRD Charge that recovers summer on, mid- and five percent of off-peak capacity costs; (2), a winter mid-peak TRD Charge that recovers all winter peak capacity costs; (3) flat cent-per-kWh Energy Charges to recover 95 percent of summer off-peak capacity costs across all TOU periods, and (4) the use of an FRD Charge to recover Grid-related costs.

- For generation, a settled generation capacity marginal cost (GCMC) value is used, with the balance of the rate design consistent with the generation rate design for Option D of the TOU-GS-2 and TOU-GS-3 rate classes, as described above.

Current Base Rate Option B is replaced with a new Option D incorporating the following rate design for TOU-8-Sub:

- Updated TOU periods per D.18-07-006.
- Customer Charge as set forth in Appendix B to the Settlement Agreement.
- For distribution, using a settled DDMC value:(1) a summer on-peak TRD Charge that recovers summer on-peak capacity costs; (2) a winter mid-peak TRD charge that recovers all winter mid-peak capacity costs; and (3) an FRD Charge that recovers Grid-related costs and summer mid- and off-peak and winter off- and SOP-peak capacity costs (no distribution costs are recovered via Energy Charges).
- For generation, a settled GCMC value is used, with the balance of the rate design consistent with the generation rate design for Option D of the TOU-GS-2 and TOU-GS-3 rate classes, as described above.

2. <u>Option E Optional Rate – Eligibility and Rate Design</u>

a) <u>Option E Eligibility for TOU-GS-2 and TOU-GS-3</u>

SCE proposed to extend the existing eligibility requirements (*i.e.*, C&I customers with demands above 20kW and up to 500 kW) to the new Option E, but would eliminate the technology- and project-size restrictions that are currently applied to Option R. DACC supported SCE's more open Option E proposal as it offers opportunities for Direct Access (DA) customers to better manage their loads and electric costs. SEIA supported SCE's proposal for Option E to be technology-agnostic and available to all customers. The Settlement Agreement adopts SCE's proposal that includes no eligibility restrictions and also exempts customers with DER technologies from Standby charges.

b) <u>Option E Rate Design for TOU-GS-2 and TOU-GS-3</u>

SCE proposed to offer Option E as the optional replacement rate for current Options A and R, which would: (1) include a Customer Charge of approximately $110/month (TOU-GS-2) and $266/month (TOU-GS-3), adjusted to recover a portion of the FLT costs in the grid distribution demand charge; (2) recover Generation Energy via TOU Energy Charges; (3) recover Generation Capacity costs entirely via TOU cent-per-kWh Energy Charges; (4) recover Distribution Peak costs entirely via cent-per-kWh Energy Charges; and (5) recover Distribution Grid costs through an FRD Charge. DACC supported SCE's more open Option E proposal as it offers opportunities for DA customers to better manage their loads and electric costs.

SEIA strongly supported the direction of SCE's proposed changes (*i.e.*, more time-dependent recovery of distribution costs). SEIA offered its own Option E proposed rates, with alternate functionalization of marginal distribution costs into coincident peak (recovered via Energy Charges), non-coincident peak (recovered via maximum non-coincident demand charges), and non-peak (flat energy rates). SEIA's proposal also utilized ORA's proposed PLRFs, and would result in a significant reduction in non-coincident demand charges.

CALSSA maintained that SCE's proposal was not a viable option for solar or paired storage, and recommended that a smaller portion of costs be recovered via peak energy charges (*i.e.,* creating a structure with a lower differential between peak and off-peak rates).

Ultimately, the Settlement Agreement adopts a compromise rate design as follows:

- Updated TOU periods per D.18-07-006.
- Customer Charge of $125.25/month (TOU-GS-2) and $307/month (TOU-GS-3).
- For distribution, recovery of 60 percent of revenues (excluding Customer Charge revenues) via TOU Energy Charges using ORA's PLRFs, 30 percent via an FRD Charge, and 10 percent via flat Energy Charges.

- For generation, recovery of energy and capacity revenues is via a TRD Charge set at 25 percent of the Standby Backup Demand Charge with the balance of revenues recovered via TOU Energy Charges.

In addition, SCE agreed to study the appropriate level of the TRD Charge and include the results of that study in its 2021 GRC Phase 2 application.

c) <u>Option E Eligibility for TOU-8</u>

Currently, Option A eligibility is limited to the following types of customers: (1) Permanent Load Shifting (PLS); (2) cold-ironing; and (3) certain Zero-Emission Vehicles (ZEVs). Option R eligibility is currently limited to customers with annual peak demands not exceeding 4 MW who install solar, wind, fuel cells or other onsite DER as defined by the California Solar Initiative (CSI) or Self-Generation Incentive Program (SGIP), whose systems have a net renewable generating capacity that is at least 15 percent of the customer's annual peak demand. SCE proposed that the eligibility for new Option E be extended to all C&I customers with demands over 500 kW (excluding certain large water pumping and agricultural customers).

CLECA strongly opposed eligibility for new Option E rates for all TOU-8 customers, raising concerns about significant cost-shifting from low-load-factor customers. EPUC and FEA concurred with CLECA.

DACC supported SCE's new, more-open Option E because it offers opportunities to DA customers to better manage their loads and electric costs. SEIA supported SCE's proposal to allow Option E to be technology-agnostic and available to all customers.

In the Settlement Agreement, the Parties adopted a compromise approach as follows:

- Option E eligibility is limited to customers with qualifying technologies, which include all technologies currently eligible for the existing Options A and R,[4] but expanded to also specifically include behind-the-meter (BTM) paired storage and BTM stand-alone storage.

- For DERs (excluding standalone storage), an eligible customer's system must have a net renewable generating capacity equal to or greater than 15 percent of the customer's annual peak demand, as recorded over the previous 12 months.
- For standalone storage, an eligible customer's system must have a minimum discharge capacity equal to or greater than 20 percent of the customer's annual peak demand, as recorded over the previous 12 months.
- Eligibility for Option E is further limited to customers with annual peak demands not exceeding 5 MW (an increase from the current 4 MW restriction).
- Customers receiving service on Option E are exempt from being required to take service on a Standby rate schedule.
- A 250 MW participation cap is imposed for customers with DER technologies, but the capacity of new customers who are utilizing technologies which would have made them eligible for Option A (*i.e.,* PLS, cold-ironing, eligible ZEVs) will not be counted against the cap.
    - For DERs, the qualifying capacity counted towards the 250 MW participation cap is the system's alternating current (AC) nameplate rating (which is consistent with the current Option R cap calculation).

---

[4] Option A is currently available to customers who participate in (PLS (eligible systems must account for at least 15 percent of the customer's annual peak demand, as recorded over the previous 12 months), cold ironing pollution mitigation programs or the charging of eligible ZEVs intended for the transport of people or goods. Option R is currently available to customers with annual peak demands not exceeding four megawatts (MW) who install, own or operate solar, wind, fuel cells or other eligible onsite Renewable Distributed Generation Technologies as defined by CSI or SGIP. Eligible systems must have a net renewable generating capacity equal to or greater than 15 percent of the customer's annual peak demand, as recorded over the previous 12 months.

- For standalone storage, the qualifying capacity counted towards the 250 MW participation cap is the discharge capacity of the storage system.
- For paired storage systems, the qualifying capacity counted towards the cap is the larger of the system's AC nameplate solar capacity or the discharge capacity of the storage system (but not both).
- The 250 MW Option E DER participation cap is incremental to the existing Option R 400 MW cap.
- SCE agrees to file information-only Advice Letters (ALs) to report on the progress towards the cap. The frequency of such ALs will be one for every 50 MW of allocated capacity (based on the date of the signed interconnection agreement for the DER) until 200 MW is reached, at which time SCE will file monthly ALs until the cap is reached. The monthly ALs will include additional data to help inform actual progress towards the cap, *e.g.,* such as how long systems have been allocated capacity under the 250 MW cap but have not yet received permission to operate (PTO).

d) <u>Option E Rate Design for TOU-8</u>

SCE proposed to establish an Option E that maintained existing Options A's and R's no-TRD structure, with the(1) Customer Charge established at the full marginal-cost-based level adjusted to recover a portion of the FLT costs in the grid distribution demand charge; (2) Generation Energy recovered through TOU Energy Charges; (3) Generation Capacity recovered entirely via TOU cent-per-kWh Energy Charges; (4) Distribution Peak recovered via a cent-per-kWh Energy Charge; and (5) Distribution Grid recovered via FRD Charges.

CLECA strongly opposed SCE's Option E proposal to recover capacity costs via Energy Charges (except to a limited extent to mitigate bill impacts for certain groups of customers).

CLECA maintained that eliminating demand charges results in customers with low load factors imposing substantial costs on the system because they do not pay for the full cost of the capacity they require (due to low-usage billing determinants). CLECA posited that the best way to recover generation costs is via a mixture of coincident demand charges and TOU-varying energy rates. EPUC and FEA generally concurred with CLECA's position.

DACC supported SCE's new, more-open Option E because it offers opportunities to DA customers to better manage their loads and electric costs.

SEIA strongly supported the direction of SCE's proposal (*i.e.*, more time-dependent recovery of distribution costs). SEIA offered its own Option E rates for Large Power customers, consistent with its proposed Option E rates for Medium Power customers (*i.e.*, the ultimate result would be a significant reduction in non-coincident demand charges).

CALSSA maintained that SCE's proposal was not a viable option for solar or paired storage, and recommended that a smaller portion of costs be recovered via peak energy charges (*i.e.*, creating a structure with a lower differential between peak and off-peak rates).

The Settlement Agreement adopts a compromise rate design:

Current Options A and R are replaced with new Option E for TOU-8-Sec and TOU-8-Pri. The rate design is identical to the rate design described above for TOU-GS-2 and TOU-GS-3 Option E (although the eligibility requirements are different), with the exception that settled DDMCs and GCMCs are additionally utilized (and the Customer Charges are as set forth in Appendix B to the Settlement Agreement).

Current Options A and R are replaced with new Option E for TOU-8-Sub, with the following rate design:

- Updated TOU periods per D.18-07-006.
- A Customer Charge as set forth in Appendix B of the Settlement Agreement.
- For distribution, using a settled DDMC value with a Peak/Grid split based on the marginal cost revenue responsibility (MCRR); (1) an FRD Charge

is used to recover Grid-related costs (22 percent of the MCRR); and (2) with the remaining revenue (78 percent of the MCRR) recovered via TOU Energy Charges using PLRFs proposed by ORA in opening testimony.

- For generation, (1) using a settled GCMC value; (2) recovery of energy and capacity revenues is via a TRD Charge set at 25 percent of the Standby Backup Demand Charge; and (3) with the balance of revenues recovered via TOU Energy Charges.

3. <u>Default CPP Rate Design</u>

The Settlement Agreement adopts SCE's uncontested proposal as modified to reflect the changes to the CPP program adopted in D.18-07-006, as follows, which shall take effect upon implementation of this Agreement:

- CPP event periods shall coincide with the updated TOU peak periods (*i.e.*, weekdays from 4-9 p.m.);
- The revised CPP event charge of $0.80/kWh shall be phased in over two years – the event charge in the first year (2019) shall be $0.40/kWh and will increase to the full $0.80/kWh in the second year (2020);
- The CPP-Lite and Capacity Reservation Level (CRL) options are eliminated, and;
- Bill protection will be offered to customers for up to one year.

C. <u>Standby Rate Design</u>

1. <u>Large Power Standby Rate Design</u>

SCE did not propose structural changes for Standby rates. SCE proposed that for TOU-8-S and TOU-8-RTP-S, distribution grid costs would be recovered via an FRD Charge and Distribution Peak costs via a TRD Charge, with supplemental and back-up TRD Charges set at their full EPMC levels and applied in both summer and winter. The Standby Algorithm adopted in SCE's last GRC Phase 2 would continue to be used to determine customers' Standby Demand and Supplemental Contract Capacity.

FEA proposed alternate TOU-8-S rates that collect capacity costs via demand charges.

The Settlement Agreement adopts the following rate design for Large Power Standby customers:

For TOU-8-S and TOU-8-RTP-S Standby customers, the rate designs will be aligned with the changes for the Option D rates described above. SCE will continue to apply the Algorithm adopted in the 2015 GRC Phase 2 to determine Standby Demand and Supplemental Contract Capacity. An alternate TOU-8-S option for RES-BCT Generating Accounts (*i.e.*, the replacement of the current Option TOU-8-S-A with TOU-8-S-LG) is also maintained.

2. <u>Medium Power Standby Rate Design</u>

The Settlement Agreement provides that Standby customers whose demands are 500 kW or lower will be served on rate schedules within their applicable rate groups with rider charges for Standby service. The Standby capacity reservation charge (CRC) shall be the lesser of the FRD Charge that is based on the customer's otherwise applicable tariff (OAT) or the Standby CRC specified for the TOU-8-S-Sec rate class. For standard Standby service, the underlying Base service will be taken on Option D. Renewable Energy Self-Generation Bill Credit Transfer (RES-BCT) customers (*i.e.,* the Generating Account) with demands of 500 kW or lower will continue to be allowed to take Standby service on an underlying Option E rate schedule (with Option E serving as the replacement for the existing Option A rates).

D. <u>EV Rate Design</u>

SCE proposed that the existing optional EV rate for customers with demands above 20 kW and up to 500 kW (*i.e.*, TOU-EV-4) be replaced with new TOU-EV-8, and the existing optional EV rate for customers with demands above 500 kW (*i.e.*, TOU-EV-6) be replaced with new TOU-EV-9. Both replacement optional EV rates would be updated to reflect new TOU periods and the bifurcated distribution grid and peak rate structures, with the distribution peak-capacity costs recovered via TOU Energy Charges. SCE proposed to grandfather the existing TOU-EV-4 distribution charge provision for customers that have an EV account located on the same premises as the non-EV host account (exempting them from FRD charges). No party addressed SCE's proposal, and the Settlement Agreement adopted it; specifically:

Schedule TOU-EV-4 will be replaced by Schedule TOU-EV-8, as adopted in D.18-05-040. Schedules TOU-EV-4/TOU-EV-8 are separately metered rates applicable solely to the charging of EVs for customers with demands above 20 kW and up to 500 kW. With regard to distribution charges, SCE will grandfather a feature that limits distribution charges for existing TOU-EV-4 customers when they are transitioned to TOU-EV-8. Because the new EV rates feature a combination of distribution energy and demand charges, the demand comparison calculation and any resulting distribution "credit" will apply to both energy and demand charges.

Schedule TOU-EV-6 will be replaced by Schedule TOU-EV-9, as adopted in D.18-05-040. Schedules TOU-EV-6/TOU-EV-9 are separately metered rates applicable solely to the charging of EVs for customers with demands exceeding 500 kW. With regard to distribution charges, SCE will grandfather a feature that limits distribution charges for existing TOU-EV-6 customers when they are transitioned to TOU-EV-9. Because the new EV rates feature a combination of distribution energy and demand charges, the demand comparison calculation and any resulting distribution "credit" will apply to both energy and demand charges.

E. <u>Real-Time Pricing (RTP) Rate Options</u>

SCE proposed to incorporate an updated RTP rate design that was subsequently adopted by D.18-07-006 regarding seven "day-type menus" instead of the previous nine "day-type menus." SCE also proposed to use an updated LOLE study to determine seasonal hourly profiles for energy and capacity, with distribution charges updated based on SCE's Option D proposals discussed extensively above.

CLECA did not oppose SCE's proposal, but recommended that SCE develop the capacity in its billing system to pass through wholesale prices for use in billing for retail sales and that SCE work with parties to develop such a pricing option in SCE's 2021 GRC Phase 2 application.

CALSSA submitted testimony that maintained that day-time energy charges on RTP rates are so low that investment in solar PV systems is even less viable than under Option E, and also that paired storage is not viable under an RTP rate structure.

The Settlement Agreement provides: The RTP rate options shall be modified to reflect the changes adopted in D.18-07-006. Settling Parties agree that an RTP rate design based on wholesale energy prices from the CAISO markets can be explored by parties in SCE's 2021 GRC Phase 2 proceeding, assuming SCE's new Customer Service Replatform (CSRP) billing system is in place (when billing system implementation issues would not preclude this type of rate design).

F. Reliability Back-Up Service Rate Design (TOU-8-RBU)

SCE proposed to retain the current treatment (*i.e.*, small Customer Charge, Generation TRD Charges and Energy Charges, with no distribution design demand recovery via TOU Energy or Demand Charges), with updates to reflect marginal-cost-based changes made to Option D (as discussed above). The Settlement Agreement adopts SCE's uncontested proposal.

G. Demand Response Credits (APS and BIP)

The Settlement Agreement adopts SCE's uncontested proposal that rate structures and rate designs associated with SCE's demand response programs, *i.e.*, BIP and APS, shall follow the respective program budget schedules adopted in D.17-12-003. BIP credits will be continued to be provided based on the difference between the customer's average on- and mid-peak demand and firm service level, where the average on- and mid-peak demands are calculated by dividing the kWh usage in the period by the number of hours in the period.

H. Energy Storage-Specific Rates

SCE did not propose storage-specific rates in its application. SEIA proposed an "Option S" rate for customers who install a certain amount of on-site, SGIP-eligible storage. That rate would be identical to the SEIA-recommended Option E rates, except that maximum demand charges for distribution costs would be converted to a daily peak demand charge, applicable during SCE's on- and mid-peak periods and designed to recover the same class revenues as the existing monthly demand charges.

The Settlement Agreement adopts a compromise position: While no rates specifically applicable only to customers who install BTM energy storage systems are adopted as part of the Agreement, SCE agreed to file a rate design window (RDW) application no later than Q4 2019 that includes the consideration of storage-specific rates that incorporate the conversion of distribution costs from a monthly maximum demand charge to a daily peak demand charge. While SCE is not obligated to propose or support such a design in its application, and may consider alternative rate structures, the targeted implementation of any rates adopted as part of this RDW application shall be late 2020, assuming CSRP is fully implemented, when billing system issues would render implementation of this type of rate design structure difficult.

I. Attrition Year Changes

As described in the RA Settlement Agreement,[5] 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-D, TOU-GS-3-D, and Schedule TOU-8-Sec-D, using a Functional system average percentage change (SAPC) adjustment. SCE will then rebalance optional rate levels to ensure revenue neutrality between the default rate schedule and the optional rate schedules within each rate class. 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 within each rate class.

IV.

REQUEST FOR ADOPTION OF THE SETTLEMENT

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.[6] This policy supports many worthwhile goals, including

---

[5] *See* Paragraph 4.B.7 of the RA Settlement Agreement.

[6] *See, e.g.,* D.88-12-083 (30 CPUC 2d 189, 221-223) and D.91-05-029 (40 CPUC 2d, 301, 326).

reducing the expense of litigation, conserving scarce Commission resources, and allowing the Parties to reduce the risk that litigation will produce unacceptable results.[7] 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.[8]

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

The prepared testimony, the Settlement Agreement itself (with its attendant Comparison Exhibit attached thereto), 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 discovery and served testimony on the issues related to Medium and Large Power rate group rate design issues. 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 in light of the inherent risks and costs of continued litigation. Without divulging the content of confidential settlement negotiations, concessions by parties on some issues were offset by concessions by other parties on other issues, as is the case with almost every settlement. The Settlement Agreement accordingly represents a series of tradeoffs, and must be viewed as a "package." No single provision should be viewed in isolation, although every individual provision is reasonable, lawful, and in the public interest.

---

[7] D.92-12-019, 46 CPUC 2d 538, 553.

[8] *See also*, *Re San Diego Gas & Electric Company,* (D.90-08-068), 37 CPUC 2d 360.

At a high level, the Settlement Agreement represents a reasonable resolution of disparate Party positions in the following ways:

First, the Settlement Agreement adopts all of SCE's uncontested proposals. These proposals were not controversial, and the Settling Parties (as sophisticated rate design intervenors) chose not to address them in testimony (or actively supported them). The Commission should deem them to be reasonable.

Second, and most importantly, where there were disputes between the Settling Parties, the Settlement Agreement adopted compromise rate designs that incorporate the following critical principles of modern Commission rate design jurisprudence:

- Further movement towards time-differentiation of distribution costs:

At a high level, the Settlement Agreement's compromise Option D and Option E rates shift cost recovery away from FRD Charges, and towards TRD and Energy Charges. FRD Charges are by definition not time-differentiated; TRD and Energy Charges (in a TOU environment), on the other hand, are. The following charts illustrate this movement towards time-differentiation from the current rates (*i.e.*, Options, B, A, and R) to the settled rates (*i.e.*, Options D and E).

Distribution Revenue Recovery Comparison		
	TOU-GS-2, Current B	TOU-GS-2, Proposed D
% in Energy	0%	13%
% in TRD	0%	35%
% in FRD	100%	53%
	TOU-GS-2, Current R	TOU-GS-2, Proposed E
% in Energy	33%	70%
% in TRD	0%	0%
% in FRD	67%	30%
	TOU-GS-3, Current B	TOU-GS-3, Proposed D
% in Energy	0%	12%
% in TRD	0%	33%
% in FRD	100%	55%
	TOU-GS-3, Current R	TOU-GS-3, Proposed E
% in Energy	50%	70%
% in TRD	0%	0%
% in FRD	50%	30%
	TOU-8-SEC, Current B	TOU-8-SEC, Proposed D
% in Energy	0%	12%
% in TRD	0%	33%
% in FRD	100%	55%
	TOU-8-SEC, Current R	TOU-8-SEC, Proposed E
% in Energy	17%	70%
% in TRD	0%	0%
% in FRD	83%	30%
	TOU-8-PRI, Current B	TOU-8-PRI, Proposed D
% in Energy	0%	12%
% in TRD	0%	32%
% in FRD	100%	56%
	TOU-8-PRI, Current R	TOU-8-PRI, Proposed E
% in Energy	28%	70%
% in TRD	0%	0%
% in FRD	72%	30%
	TOU-8-SUB, Current B	TOU-8-SUB, Proposed D
% in Energy	0%	0%
% in TRD	0%	46%
% in FRD	100%	54%
	TOU-8-SUB, Current R	TOU-8-SUB, Proposed E
% in Energy	48%	78%
% in TRD	0%	0%
% in FRD	52%	22%

These settled rate designs embody the Commission's recent guidance to shift cost recovery away from non-coincident peak methods (*e.g.*, FRD Charges), and towards rate design structures that incorporate time-differentiation (*e.g.*, TOU Energy and TRD Charges).

- Providing reasonable rate choice optionality that recognizes changing customer technology preferences while limiting cost-shifts to other customers:

The Settlement Agreement's optional rate (Option E) adopts a rate design that will benefit certain customer groups who otherwise may be disadvantaged by the new TOU period definitions and updates to the underlying Option D rate design. The compromise rate does not eliminate non-coincident demand charges (*e.g.*, between 22-30 percent of distribution revenues are recovered through an FRD rate), but it reduces them to make the rates more aligned with time-dependent cost-causation, which helps to provide more actionable price signals to customers considering investing in DER technology. In addition, Option E removes certain existing limitations that restricted Option R rates to certain kinds of technologies for customers in the TOU-GS-2 and TOU-GS-3 classes. The new Option E is instead technology-agnostic for the Medium Power Rate group. At the same time, for TOU-8, the Settlement Agreement retains technology-based eligibility requirements and further caps participation in the new rate to 250 MW in order to limit potential revenue shifts to non-participating customers as the new rate design is implemented for eligible customers. Overall, the Settlement Agreement's Option E strikes an appropriate balance among several considerations, namely customer rate choice (especially for new DER technologies), limiting or safeguarding against revenue-shifting to other customer groups, and maintaining an appropriate consideration of equity among high- and low-load-factor customers within a rate class.

Third, the Settlement Agreement commits the Parties to continue to study and discuss various rate design issues in the future. Specifically, the Settlement Agreement provides for the following future Party engagements on rate design issues:

- New optional Rate Option E includes TRD Charges for the first time (the optional rates it replaces do not include one). SCE has committed to exploring the appropriate TRD Charge level for this new rate (based on real-world results from the implementation of this rate in 2019) and include the results of that study as part of its 2021 GRC Phase 2 showing.

- SCE has agreed to file an RDW application in late 2019 that includes consideration of SEIA's "Option S" optional rate design structure (that includes daily demand charges instead of non-coincident demand charges).
- The Parties have agreed that wholesale energy prices from the CAISO markets should be explored in the 2021 GRC Phase 2 as a basis for RTP pricing rate design.

Fourth, the Settlement Agreement promotes transparency for customers by committing SCE to file periodic Advice Letters to report on the progress towards the TOU-8 250 MW cap for new Option E. The Advice Letters are intended to reduce the difficulties certain customers have experienced with the current Option R cap/queue.

A. The Settlement Agreement Should Be Adopted as a Whole as it is a Compromise of Interests

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, 2019. In order to accomplish this, the Settling Parties recommend the following time periods provided by Rule 12.2 for comments and replies to comments on the Settlement Agreement. 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.

Event	**Date**
Motion filed for Adoption of the Settlement Agreement	August 3, 2018
Opening comments, if any, on the Settlement Agreement	September 3, 2018
Reply comments, if any, on the Settlement Agreement	September 17, 2018
Hearing on the Settlement Agreement, if necessary	During the currently-reserved time period for settlement/evidentiary hearings (*i.e.*, August 9, 2018).

VI.

CONCLUSION

WHEREFORE, the Settling Parties respectfully request that the Assigned Commissioner, Assigned ALJs, 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,

FADIA R. KHOURY
RUSSELL A. ARCHER

/s/ Russell A. Archer

By: Russell A. Archer

Attorneys for
SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770
Telephone: (626) 302-2865
E-mail: Russell.Archer@sce.com

And on behalf of the Settling Parties pursuant to Rule 1.8(d).

August 3, 2018

Appendix 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, and Design Rates.	A.17-06-030 (Filed June 30, 2017)

MEDIUM AND LARGE POWER RATE GROUP DESIGN SETTLEMENT AGREEMENT

Dated: **August 3, 2018**

Medium and Large Power Rate Group Design Settlement Agreement

Table of Contents

Medium and Large Power Rate Group Design Settlement Agreement

Table of Contents (Continued)

Table of Contents (Continued)

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, and Design Rates.	A.17-06-030 (Filed June 30, 2017)

MEDIUM AND LARGE POWER RATE DESIGN SETTLEMENT AGREEMENT

This Medium and Large Power 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 Large Energy Consumers Association (CLECA); Energy Users Forum (EUF); Solar Energy Industries Association (SEIA); the Energy Producers and Users Coalition (EPUC); California Manufacturers & Technology Association (CMTA); Direct Access Customer Coalition (DACC); and, California Solar & Storage Association (CALSSA) (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 & Electric Company (SDG&E).

C. CLECA is an organization of large industrial electric bundled service, Community Choice Aggregation (CCA) and Direct Access (DA) customers of SCE and PG&E. These companies are in the steel, cement, industrial gas, pipeline, minerals extraction, cold storage, and beverage industries.

D. DACC is a regulatory alliance of commercial, industrial and governmental customers who have opted for DA service for some or all of their electric loads.

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 kilowatts (kW).

F. CMTA is a trade association representing the interests of 25,000 large and small manufacturers in California and 1.2 million employees. Many of its members receive electrical service from SCE either bundled service or DA customers.

G. 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.

H. 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 Inc., and California Resources Corporation.

I. CALSSA is the California trade group of the solar power and energy storage industries. CALSSA represents 500 member companies, including installers, manufacturers, financers, consultants, service providers, and research groups.

2. <u>Definitions</u>

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. "AC" means "alternating current."

B. "Added Facilities" are customer-dedicated, SCE-maintained electrical distribution facilities as defined in SCE's Electric Rule 2 tariff.

C. "AL" means an Advice Filing, sometimes referred to as an Advice Letter filing, at the CPUC.

D. "APS" means Automatic Powershift.

E. "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.

F. "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.

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

H. "BTM" means "behind-the-meter."

I. "CAISO" means the California Independent System Operator.

J. "CA" means "Community Aggregation."

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

L. "CCA" means Community Choice Aggregation.

M. "C&I" means Commercial and Industrial customers.

N. "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 percent 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).

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

P. "CSRP" means SCE's Customer Service Replatform effort currently underway to replace SCE's existing customer care and billing systems.

Q. "Customer Charges" mean the fixed dollar-per-month charges applied to customers in the C&I rate classes that are designed to recover the fixed customer costs of connection to SCE's system.[1]

R. "DA" means Direct Access.

S. "Default Rate" means the rate schedule on which the customer is automatically placed when starting service unless the customer requests otherwise.

T. "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 in any time period (*i.e.*, FRD), or during a specified time-of-use (TOU) period (*i.e.*, TRD), within a billing period. Demand Charges recover a portion of SCE's distribution and generation costs, where such charges apply to a specific rate schedule.

U. "DDMC" or "Design Demand Marginal Costs" means the incremental cost associated with providing additional capacity on the distribution system.

V. "DER" means "Distributed Energy Resource."

W. "Distribution Grid" (or "Grid") refers to the portion of DDMCs that are not Distribution Peak-related.

X. "Distribution Peak" (or "Peak") refers to the portion of DDMCs that are primarily sized to support the time-sensitive nature of coincident peak demand on the distribution system.

Y. "Energy Charges" mean the dollar-per-kilowatt-hour (kWh) charges that recover (1) the portion of SCE's generation services revenues not recovered in TRD Charges; (2) the portion of SCE's delivery services revenues that are not recovered in TRD, FRD or Customer 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, demand response programs, and CPUC reimbursement fees). Energy Charges are designed to provide a price signal consistent with marginal cost differentials in TOU Energy Charges, where TOU Energy Charges apply to a specific schedule.

[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.

Z. "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).

AA. "EV" means "electric vehicle."

BB. "Facilities Related Demand Charges" or "FRD Charges" mean the charges applied to customers' monthly peak demands that are not differentiated by TOU or by season, and that are designed to recover certain transmission and distribution costs that are defined to be unrelated to time of use.

CC. "FLT" means "final line transformer."

DD. "Flexible Generation Capacity" (i.e., "flex" or "ramp") refers to the portion of GCMC required to meet system ramping needs.

EE. "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.

FF. "GCMC" means "generation capacity marginal costs."

GG. "Generation Peak" refers to the portion of GCMCs that are incurred to support the electric system during maximum system demand.

HH. "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.

II. "Large Power Rate Group" means the following SCE rate classes: (1) the TOU-8 rate classes, 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 classes, with service voltage differentiation being the same as the three TOU-8 rate classes.

JJ. "LOLE" means "loss of load expectation," and it represents the expectation that available generation capacity will be inadequate to supply customer demand at any given moment.

KK. “MECs” means “Marginal Energy Costs.”

LL. “Medium Power Rate Group” means the TOU-GS-2 rate class, 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 class, which is comprised of C&I customers with demands between 200 kW and 500 kW.

MM. “OAT” means the customer’s otherwise applicable tariff.

NN. “Paired storage” means BTM electric storage technology including, but not limited to, electric battery systems, that are combined behind the same meter or billed on the same service account as other DERs, usually solar.

OO. “PLS” or “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.

PP. “PLRF” means “Peak Load Risk Factor,” and represents the methodology used to assess capacity constraints on the distribution system and to assign peak-capacity-related design demand marginal costs to TOU periods.

QQ. “RA Settlement Agreement” means the Revenue Allocation Settlement Agreement filed in this proceeding on July 3, 2018.

RR. “RDW” means SCE’s 2016 Rate Design Window proceeding, A.16-09-003.

SS. “Renewable Distributed Generation Technologies” means renewable generation technology as defined in the Statewide California Solar Initiative (CSI), the Self-Generation Incentive Program (SGIP), or their successors.

TT. “RECC” or “Real Economic Carrying Charge,” means a constant payment in real dollars that includes the recovery of the capital investment, earnings, taxes, and other capital carrying costs. The RECC when escalated at the rate of inflation over the life of the asset recovers the net present value of revenue requirement of a utility investment. It also represents the value of deferring a utility investment by a year.

UU. “RTP” means Real Time Pricing.

VV. “Standby Algorithm,” or “Algorithm” is the algorithm adopted by the CPUC in D.16-03-030, approving SCE’s 2015 GRC Phase 2.

WW. “Standby Demand Backup Charge” are TRD Charges based on the lesser of the Standby Demand or the maximum Backup Demand for the relevant TRD period calculated for each 15-minute interval as the difference between the 15-minute interval maximum SCE metered demand (kW) and the 15-minute interval Intermediate Supplemental Demand, but not less than zero.

XX. "Standalone storage" means BTM electric storage technology including, but not limited to, electric battery systems that are not combined behind the same meter or billed on the same service account as other DERs.

YY. "SCC" or Supplemental Contract Capacity is the level of kW regularly served by SCE for Standby customers.

ZZ. "Time-Related Demand Charges" or "TRD Charges" are generation or distribution marginal-cost-based, capacity-related charges assigned to TOU periods based on loss-of-load probabilities during the TOU periods.

AAA. "TOU" means time-of-use. TOU periods 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, and reflect the TOU periods adopted in D. 17-08-006.

BBB. "ZEV" means Zero-Emissions Vehicle.

3. <u>Recitals</u>

A. In Phase 2 of SCE's 2018 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 30, 2017, SCE served its initial prepared testimony regarding marginal costs, revenue allocation and rate design in Application (A.)17-06-030.

C. On November 22, 2017, the Assigned Commissioner and Assigned Administrative Law Judge issued a Scoping Memo and Ruling following a November 2, 2017 prehearing conference.

D. ORA served its initial testimony on February 16, 2018. Intervenors, including the Settling Parties to this Agreement, served their initial prepared testimony on March 23, 2018.

E. The following intervenors submitted prepared testimony regarding Medium and Large Power Rate Design Issues: FEA, CLECA, EPUC, DACC, SEIA and CALSSA that are addressed by this Settlement Agreement.

F. 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 April 6, 2018.

G. Continuing settlement discussions occurred among the parties after April 6, 2018. Specific to this Settlement Agreement, the Settling Parties commenced "Track No. 4" settlement discussions on June 4, 2018.

H. 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 Rate Group rates resulting from this Settlement Agreement. Consistent with Paragraph 11 of this Settlement Agreement, these class average summaries are for illustrative purposes only. The rate summaries will be adjusted to reflect SCE's actual revenue requirements in accordance with the provisions of the RA Settlement Agreement when rates are first implemented pursuant to the provisions of this Agreement.

I. The Settling Parties have evaluated the impacts of the various proposals in this proceeding and desire to resolve all issues related to rate design regarding Medium and Large Power Rate Group customers as set forth in this Agreement beginning with the implementation of a CPUC decision approving this Agreement, and, in 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 $11,420 million described in more detail in Paragraph 4.B of the 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 RA Settlement Agreement to reflect SCE's actual total system revenue requirement when this Agreement is implemented.

B. Common Rate Design Elements

Consistent with SCE's Application, rate structures for the Medium and Large Power Rate Groups will generally consist of Customer Charges, TOU Energy Charges, TRD Charges, and FRD Charges. Default CPP rate schedules will continue to apply to the TOU-GS-3 and TOU-8 rate classes, and will also newly apply to the TOU-GS-2 rate class upon implementation of a decision approving this Agreement in accordance with D.18-07-006 (resolving SCE's 2016 RDW Application) – which adopted default CPP for the TOU-GS-2 rate class.[2] Optional RTP rate schedules will also continue to be available.

1) TOU Periods and Seasonal Definitions

SCE's existing TOU periods shall be modified to conform to the TOU periods adopted in D.18-07-006, as reflected in Appendix C of the Agreement. SCE's summer and winter season definitions for C&I customers shall not be modified from their current definitions (*i.e.,* summer: June through September; winter: October through May).

2) Customer Charges

Customer Charges shall be derived based on SCE's as-proposed RECC customer marginal cost method, but adjusted to recover a portion (*i.e.*, the first 50 kVA) of the FLT costs in the FRD Charge. Customer Charges shall be set at the full EPMC level for all customers in the

---

[2] Customers must have been served on a TOU rate for at least 24 months before they are eligible for default CPP. Additionally, customers with pending DA, CCA or CA enrollments are not subject to default CPP, as provided in D.18-07-006.

Medium and Large Power Rate Groups. Illustrative monthly Customer Charges are listed in Table C&I-1, below:

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

Rate Group	Customer Charge
Flat GS-2	$125.25
TOU-GS-2	$125.25
TOU-GS-3	$307.00
TOU-8-SEC	$459.50
TOU-8-PRI	$244.75
TOU-8-SUB	$1,624.75

When this Agreement is first implemented in 2019, these estimated Customer Charges shall be adjusted, as necessary, consistent with the then-current revenues allocated to each rate group in accordance with the RA Settlement Agreement.[4] Thereafter, these Customer Charges shall be adjusted on a Functional SAPC basis.

3) <u>Energy Charges</u>

Proposed Energy Charges based on SCE's 2019 estimated consolidated revenue requirement are set forth in Appendix B.[5] When this Agreement is first implemented in 2019, these estimated Energy Charges shall be adjusted, as necessary, consistent with the then-current revenues allocated to each rate group in accordance with the RA Settlement Agreement.[6] Thereafter, these estimated Energy Charges shall be adjusted consistent with Paragraph 4.B.7 of the RA Settlement Agreement when SCE's authorized revenue requirements change.

---

[3] Illustrative Customer Charges for the Standby TOU-8-Sec, -Pri, and -Sub rate classes are equal to the Customer Charges for the corresponding TOU-8-Sec, -Pri, and -Sub rate classes, and are shown in Appendix B.

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

[5] The estimated consolidated revenue requirement, as defined in Paragraph 4.B.1 of the RA Settlement Agreement, is $11,420 million.

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

a) Non-Generation-Related Energy Charges

Energy Charges that are designed to recover revenues associated with the following categories -- transmission (TOTCA), distribution,[7] public purpose programs, new system generation service, nuclear decommissioning, California Department of Water Resources bond charges, and the CPUC reimbursement fee -- shall be established on the basis of the specific functional authorized revenue requirements and the terms specified in the RA Settlement Agreement.

b) Generation-Related Energy Charges

Except where otherwise specified in this Agreement, generation-related Energy Charges shall be established based on the TOU marginal energy costs used in the 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 period.

a) TRD Charges

The base rate (*i.e.,* Option D) option for each rate class will continue to collect most generation capacity costs via TRD Charges. However, to reflect the impact of ramp and the need for flexible capacity year-round, generation capacity TRD charges shall apply both in the summer on-peak period (as they currently do) and also in the winter mid-peak period.[8] The amount of generation revenues recovered via TRD Charges is discussed for each rate class in the "Base and Optional Rates and Rate Design" section below. Additionally, as a first step to introducing time-differentiation into distribution rates, this Settlement Agreement establishes new distribution TRD Charges in both the summer on-peak and winter mid-peak periods. The amount of distribution revenues recovered via the new distribution TRD Charges is discussed

---

[7] The recovery of distribution revenues via Energy Charges varies based on the specific rate option, and is further discussed in the "Base and Optional Rates and Rate Design" section below.

[8] TRD charges do not apply on weekends or holidays in the winter mid-peak period.

for each rate class in the "Base and Optional Rates and Rate Design" section below. To mitigate bill impacts, different values for GCMCs and DDMCs than those used in the RA Settlement Agreement are used for the TOU-8 rate classes when establishing the TRD Charges for the base rate options.

Table C&I-2
Illustrative TRD Charges (Option D)[9]

	TOU-GS-2	TOU-GS-3	TOU-8-Sec	TOU-8-Pri	TOU-8-Sub
Summer On-Peak ($/kW)	26.81	27.11	29.79	28.73	23.57
Winter Mid-Peak ($/kW)	6.98	6.50	7.18	7.14	5.21

Table C&I-3
Estimated Backup and Supplemental TRD Charges for Standby (Based on Option D)[10]

	TOU-8-S-Sec	TOU-8-S-Pri	TOU-8-S-Sub
Backup Summer On-Peak ($/kW)	23.11	19.06	6.57
Backup Winter Mid-Peak $/kW	5.45	5.35	1.39
Supplemental Summer On-Peak $/kW	29.79	28.73	23.57
Supplemental Winter Mid-Peak $/kW	7.18	7.14	5.21

To offer customers a menu of rate options, this Settlement Agreement also makes available "Option E" rates (with eligibility restrictions for the TOU-8 rate classes, as discussed below), which include a much lower generation TRD charge compared to Option D and no distribution TRD Charge. The use of a generation TRD Charge in the Option E rates is a change from the existing Option A and R rate structures, which include no TRD Charges but include a higher FRD charge (see Table C&I-8.)

9 These TRD Charges combine both the generation and distribution TRD amounts; the individual components are provided in Appendix B.

10 These TRD Charges combine both the generation and distribution TRD amounts; the individual components are provided in Appendix B.

The establishment of the TRD Charge is an incremental step to address existing equity considerations between high- and low-load-factor customers. The Option E TRD Charge is set at 25 percent of the Standby backup demand charge for each rate class. As part of this Agreement, SCE agrees to study the appropriate level for TRD Charges within an Option E-type structure and report the results of its study in its 2021 GRC Phase 2 application.

Table C&I-4
Illustrative TRD Charges (Option E)

	TOU-GS-2	**TOU-GS-3**	**TOU-8-Sec**	**TOU-8-Pri**	**TOU-8-Sub**
Summer On-Peak ($/kW)	3.46	3.38	4.01	3.44	1.37
Winter Mid-Peak ($/kW)	0.74	0.64	0.82	0.91	0.32

When this Agreement is first implemented, the illustrative TRD Charges shall be adjusted, as necessary, consistent with the then-current revenues allocated to each rate group in accordance with the RA Settlement Agreement.[11] Thereafter, these TRD Charges shall be adjusted consistent with Paragraph 4.B.7 of the RA Settlement Agreement for each individual rate class when SCE's authorized generation and distribution revenues change.

b) **FRD Charges**

Both Options D and E (and the Standby rate options) include a non-coincident FRD Charge (also CRC Charges for Standby), which this Agreement establishes 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 classes. For distribution-related revenues, with the exception of the TOU-8-Sub rate class, all other rates for medium and large power rate classes utilize the FRD Charge to recover only Distribution Grid-related costs in the Option D rate designs. For TOU-8-Sub, Option D, the FRD Charge recovers Distribution Grid-related costs and non-peak (*i.e.,* summer mid- and off-peak and winter off- and SOP-

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

peak) distribution capacity costs. For the Option E rates, with the exception of TOU-8-Sub, 30 percent of distribution revenues are recovered via the FRD Charge. For TOU-8-Sub, Option E, only Distribution Grid-related costs are recovered via the FRD Charge.

Table C&I-5
Illustrative FRD Charges (Option D)

	TOU-GS-2	TOU-GS-3	TOU-8-Sec	TOU-8-Pri	TOU-8-Sub
FRD Charge ($/kW)	11.41	12.47	12.70	12.48	6.39

Table C&I-6
Illustrative CRC and FRD Charges for Standby (based on Option D)

	TOU-8-S-Sec	TOU-8-S-Pri	TOU-8-S-Sub
FRD Charge ($/kW)	12.70	12.48	6.39
CRC Charge ($/kW)	10.45	6.89	0.77

Table C&I-7
Illustrative FRD Charges (Option E)

	TOU-GS-2	TOU-GS-3	TOU-8-Sec	TOU-8-Pri	TOU-8-Sub
FRD Charge ($/kW)	8.19	8.86	9.05	8.83	5.30

To demonstrate the impact of incorporating the time-differentiation of distribution costs into rates as part of this Agreement, Table C&I-8 below provides a comparison of the amount of distribution revenue recovery included in Energy Charges, TRD Charges and FRD Charges for the existing C&I rates (*i.e.*, Options B and R) and the new proposed C&I rates (*i.e.*, Options D and E). All other things being equal, a rate design that recovers more costs via Energy and TRD Charges instead of FRD charges allows for greater time differentiation, as Energy Charges (in a TOU environment) and TRD Charges vary according to different cost periods of the day and year.

Table C&I-8
Comparison of Distribution Revenue Recovery for Existing Rates and Proposed Rates

	TOU-GS-2, Current B	TOU-GS-2, Proposed D
% in Energy	0%	13%
% in TRD	0%	35%
% in FRD	100%	53%

	TOU-GS-2, Current R	TOU-GS-2, Proposed E
% in Energy	33%	70%
% in TRD	0%	0%
% in FRD	67%	30%

	TOU-GS-3, Current B	TOU-GS-3, Proposed D
% in Energy	0%	12%
% in TRD	0%	33%
% in FRD	100%	55%

	TOU-GS-3, Current R	TOU-GS-3, Proposed E
% in Energy	50%	70%
% in TRD	0%	0%
% in FRD	50%	30%

	TOU-8-SEC, Current B	TOU-8-SEC, Proposed D
% in Energy	0%	12%
% in TRD	0%	33%
% in FRD	100%	55%

	TOU-8-SEC, Current R	TOU-8-SEC, Proposed E
% in Energy	17%	70%
% in TRD	0%	0%
% in FRD	83%	30%

	TOU-8-PRI, Current B	TOU-8-PRI, Proposed D
% in Energy	0%	12%
% in TRD	0%	32%
% in FRD	100%	56%

	TOU-8-PRI, Current R	TOU-8-PRI, Proposed E
% in Energy	28%	70%
% in TRD	0%	0%
% in FRD	72%	30%

	TOU-8-SUB, Current B	TOU-8-SUB, Proposed D
% in Energy	0%	0%
% in TRD	0%	46%
% in FRD	100%	54%

	TOU-8-SUB, Current R	TOU-8-SUB, Proposed E
% in Energy	48%	78%
% in TRD	0%	0%
% in FRD	52%	22%

5) **Voltage Discounts**

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 classes, as indicated in Appendix B. The TOU-8 and Standby rate classes have voltage-differentiated rates, as reflected in the applicable tariffs, with the exception of service provided at the 220 kV level or higher.

6) **Power Factor Adjustments**

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-04A. Power factor adjustments paid by certain customers shall be as proposed by SCE in its testimony, which is $0.54 $/kVAR for service at or above 50 kV and $0.60/kVAR for service at less than 50 kV.[12]

C. Base and Optional Rates and Rate Design (Non-Standby)

1) Option D Base Rate -- Eligibility Requirements and Rate Design

a) Option D Eligibility for TOU-GS-2 and TOU-GS-3

Existing eligibility requirements are maintained (*i.e.,* C&I customers with demands above 20 kW up to 500 kW with no other eligibility restrictions).

b) Option D Rate Design for TOU-GS-2 and TOU-GS-3

Current Base Rate Option B is replaced with a new Option D incorporating the following rate design:

- Updated TOU periods per D.18-07-006.
- A Customer Charge of $125.25/month (TOU-GS-2) and $307/month (TOU-GS-3).

---

[12] Exhibit SCE-04A, pp. 16-17.

- For distribution, a settled DDMC value, a summer on-peak TRD Charge that recovers summer on-, mid- and five percent of off-peak capacity costs; a winter mid-peak TRD charge that recovers all winter peak capacity costs; flat cent-per-kWh Energy Charges to recover 95 percent of summer off-peak capacity costs across all TOU periods; and the use of an FRD Charge to recover Grid-related costs.
- For generation, peak and capacity costs are allocated to TOU periods using LOLE; summer on-peak and winter capacity costs are recovered via the summer on-peak and winter mid-peak TRD Charges, while summer mid- and off-peak capacity costs are included in summer on- and mid-peak energy charges; and, generation energy costs are recovered via volumetric TOU Energy Charges.

c) <u>Option D Eligibility for TOU-8</u>

Existing eligibility requirements are maintained (*i.e.,* C&I customers with demands exceeding 500 kW but excluding certain large water pumping and agricultural customers).

d) <u>Option D Rate Design for TOU-8</u>

Current Base rate Option B is replaced with a new Option D incorporating the following rate design for *TOU-8-Sec* and *TOU-8-Pri*:

- Updated TOU periods per D.18-07-006.
- A Customer Charge as set forth in Appendix B hereto.
- For distribution, using a settled DDMC value, a summer on-peak FRD Charge that recovers summer on, mid- and five percent of off-peak capacity costs, a winter mid-peak TRD Charge that recovers all winter peak capacity costs, flat cent-per-kWh Energy Charges to recover 95 percent of summer off-peak capacity costs across all TOU periods, and the use of an FRD Charge to recover Grid-related costs.
- For generation, a settled GCMC value is used, with the balance of the rate design consistent with the generation rate design for Option D of the TOU-GS-2 and TOU-GS-3 rate classes, as described above.

Current Base rate Option B is replaced with a new Option D incorporating the following rate design for *TOU-8-Sub*:

- Updated TOU periods per D.18-07-006.
- A Customer Charge as set forth in Appendix B hereto.
- For distribution, using a settled DDMC value, a summer on-peak TRD Charge that recovers summer on-peak capacity costs, a winter mid-peak TRD charge that recovers all winter mid-peak capacity costs, and an FRD Charge that recovers Grid-related costs and summer mid- and off-peak and winter off- and SOP-peak capacity costs (no distribution costs are recovered via Energy Charges).
- For generation, a settled GCMC value is used, with the balance of the rate design consistent with the generation rate design for Option D of the TOU-GS-2 and TOU-GS-3 rate classes, as described above.

2) <u>Option E Optional Rate – Eligibility Requirements and Rate Design</u>

a) <u>Option E Eligibility for TOU-GS-2 and TOU-GS-3</u>

The current eligibility criteria (*i.e.*, C&I customers with demands above 20 kW up to 500 kW) is retained, except that the technology and system-size restrictions on current Option R participation are eliminated. Customers both with and without DERs are also eligible for Option E, and those receiving service on Option E are exempt from being required to take service on a Standby rate schedule.

b) <u>Option E Rate Design for TOU-GS-2 and TOU-GS-3</u>

Current Base Rate Options A and R are replaced with new Option E, with the following rate design:

- Updated TOU periods per D.18-07-006.
- A Customer Charge of $125.25/month (TOU-GS-2) and $307/month (TOU-GS-3).
- For distribution, recovery of 60 percent of revenues (excluding Customer Charge revenues) via TOU Energy Charges using PLRFs as proposed by the

Office of Ratepayer Advocates (ORA) in its opening testimony,[13] 30 percent via an FRD Charge, and 10 percent via flat Energy Charges.

- For generation, recovery of energy and capacity revenues is via a TRD Charge set at 25 percent of the Standby Backup Demand Charge with the balance of revenues recovered via TOU Energy Charges.

c) **Option E Eligibility for TOU-8**

Current Option A and R eligibility requirements for TOU-8 customers are modified for new Option E as follows:

- Option E eligibility is limited to customers with qualifying technologies, which include all technologies currently eligible for the existing Options A and R,[14] but expanded to also specifically include BTM paired storage and BTM stand-alone storage.
- For DERs (excluding standalone storage), an eligible customer's system must have a net renewable generating capacity equal to or greater than 15 percent of the customer's annual peak demand, as recorded over the previous 12 months.
- For standalone storage, an eligible customer's system must have a minimum discharge capacity equal to or greater than 20 percent of the customer's annual peak demand, as recorded over the previous 12 months.
- Eligibility for Option E is further limited to customers with annual peak demands not exceeding 5 MWs (an increase from the current 4 MW restriction under Option R).

---

[13] ORA Testimony on Southern California Edison Company's 2018 GRC Phase 2, Chapter 4, p. 4-22.

[14] Option A is currently available to customers who participate in PLS (eligible systems must account for at least 15 percent of the customer's annual peak demand, as recorded over the previous 12 months), cold ironing pollution mitigation programs or the charging of eligible ZEVs intended for the transport of people or goods. Option R is currently available to customers with annual peak demands not exceeding four megawatts (MW) who install, own or operate solar, wind, fuel cells or other eligible onsite Renewable Distributed Generation Technologies as defined by CSI or SGIP. Eligible systems must have a net renewable generating capacity equal to or greater than 15 percent of the customer's annual peak demand, as recorded over the previous 12 months.

- Customers receiving service on Option E are exempt from being required to take service on a Standby rate schedule.
- A 250 MW participation cap is imposed for customers with DER technologies, but the capacity of new customers who are utilizing technologies that would have made them eligible for Option A (*i.e.,* PLS, cold-ironing, eligible ZEVs) will not be counted against the cap.
    - For DERs, the qualifying capacity counted towards the 250 MW participation cap is based on the system's AC nameplate rating (which is consistent with the current Option R cap calculation).
    - For standalone storage, the qualifying capacity counted towards the cap is the discharge capacity of the storage system.
    - For paired storage systems, the qualifying capacity counted towards the cap is the larger of the system's AC nameplate solar capacity or the discharge capacity of the discharge storage system (but not both).
    - The 250 MW Option E DER participation cap is incremental to the existing Option R 400 MW cap.
    - SCE agrees to file information-only ALs to report on the progress towards the cap. The frequency of such ALs will be one for every 50 MW of allocated capacity (based on the date of the signed interconnection agreement for the DER) until 200 MW is reached, at which time SCE will file monthly ALs until the cap is reached. The monthly ALs will include additional data to help inform actual progress towards the cap, *e.g.,* such as how long systems have been allocated capacity under the 250 MW cap but have not yet received permission to operate (PTO).

d) **Option E Rate Design for TOU-8**

Current Rate Options A and R are replaced with new Option E for *TOU-8-Sec* and *TOU-8-Pri*. The rate design is identical to the rate design described above for TOU-GS-2 and TOU-GS-3 Option E, with the exception that settled DDMCs and GCMCs are additionally utilized (and the Customer Charges are as set forth in Appendix B).

Current Rate Options A and R are replaced with new Option E for *TOU-8-Sub*, with the following rate design:

- Updated TOU periods per D.18-07-006.
- A Customer Charge as set forth in Appendix B.
- For distribution, using a settled DDMC value with a Peak/Grid split based on the relative marginal cost revenue responsibility (MCRR), an FRD Charge is used to recover Grid-related costs (22 percent of the MCRR) with the remaining revenue (78 percent of the MCRR) recovered via TOU Energy Charges using PLRFs proposed by ORA in opening testimony.[15]
- For generation, using a settled GCMC value, recovery of energy and capacity revenues is via a TRD Charge set at 25 percent of the Standby Backup Demand Charge with the balance of revenues recovered via TOU Energy Charges.

3) Default CPP Rate Design

The proposed CPP rates reflect the changes to the CPP program adopted in D.18-07-006, as follows, which shall take effect upon implementation of this Agreement:

- CPP event periods shall coincide with the updated TOU peak periods (*i.e.*, weekdays from 4-9 p.m.);
- The revised CPP event charge of $0.80/kWh shall be phased in over two years – the event charge in the first year (2019) shall be $0.40/kWh and will increase to the full $0.80/kWh in the second year (2020);
- The CPP-Lite and Capacity Reservation Level (CRL) options are eliminated, and,
- Bill protection will be offered to customers for up to one year.

D. Standby Rate Design

1) Large Power

Standby customers with demands of more than 500 kW are classified into three rate classes, which are differentiated by the voltage at which service is provided. These rate groups are

[15] ORA Testimony on Southern California Edison Company's 2018 GRC Phase 2, Chapter 4, p. 4-22.

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 method for determining standby billing attributes (*i.e.*, Standby Demand and Supplemental Contract Capacity) used in SCE's Standby rate was fundamentally altered in SCE's last GRC Phase 2 (approved by D.16-03-030). This Settlement Agreement does not structurally change the Standby rate design, nor does it change the method for determining billing attributes. Instead, in this Settlement Agreement, the Parties agree that for TOU-8-S and TOU-8-RTP-S Standby customers, the rate designs will be aligned with the changes for the Option D rates described above. SCE will continue to apply the Algorithm adopted in the 2015 GRC Phase 2 to determine Standby Demand and Supplemental Contract Capacity.

a) <u>TOU-8-LG RES-BCT Service for Customers with Demands Greater than 500 kW</u>

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 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. Eligibility for Schedule TOU-8 Standby Option LG (which is a replacement for the existing TOU-8-S, Option A adopted in the 2015 GRC Phase 2 decision) will continue to be limited to customers taking service on Schedule RES-BCT (*i.e.*, the generating account only). This RES-BCT Option will be closed to new customers (in all rate groups eligible for this option) upon SCE reaching 125 MW of eligible installed capacity, representing SCE's designated share of the 250 MW statewide RES-BCT capacity cap.

(1) **TRD Charges**

TRD Charges for TOU-8 Standby, Option LG will apply only to Backup Service and shall be designed consistent with the TRD Charges for Option D for the corresponding TOU-8 rate classes.

(2) **Energy Charges**

All kWh usage for Standby Service, whether for Supplemental, Backup, or Maintenance Service, will be charged Supplemental Energy Charges that are determined consistent with the Energy Charges for the corresponding TOU-8 rate classes. The energy rates for Schedule TOU-8 Standby, Option LG, 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.

2) **Medium Power**

Standby customers whose demands are 500 kW or lower will be treated similarly to customers in the TOU-8-S rate classes, 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 class. For standard Standby service, the underlying Base service will be taken on Option D. RES-BCT customers (*i.e.*, the Generating Account) with demands of 500 kW or lower will continue to be allowed to take Standby service on an underlying Option E rate schedule (with Option E serving as the replacement for the existing Option A rates).

E. EV Rates

1) Schedule TOU-EV-4 / TOU-EV-8

Schedule TOU-EV-4 will be replaced by Schedule TOU-EV-8, as adopted in D.18-05-040. Schedules TOU-EV-4/TOU-EV-8 are separately metered rates applicable solely to the charging of EVs for customers with demands above 20 kW and up to 500 kW. With regard to distribution charges, SCE will grandfather a feature that limits distribution charges for existing TOU-EV-4 customers when they are transitioned to TOU-EV-8. Because the new EV rates feature a combination of distribution energy and demand charges, the demand comparison calculation and any resulting distribution "credit" will apply to both energy and demand charges.

2) Schedule TOU-EV-6 / TOU-EV-9

Schedule TOU-EV-6 will be replaced by Schedule TOU-EV-9, as adopted in D.18-05-040. Schedules TOU-EV-6/TOU-EV-9 are separately metered rates applicable solely to the charging of EVs for customers with demands exceeding 500 kW. With regard to distribution charges, SCE will grandfather a feature that limits distribution charges for existing TOU-EV-6 customers when they are transitioned to TOU-EV-9. Because the new EV rates feature a combination of distribution energy and demand charges, the demand comparison calculation and any resulting distribution "credit" will apply to both energy and demand charges.

F. Real Time Pricing (RTP) Rate Options (including TOU-8-RTP / TOU-8-RTP-S)

The RTP rate options shall be modified to reflect the changes adopted in D.18-07-006. Illustrative rates reflecting these changes and modifications to make the rates revenue neutral to the applicable rate classes are included in Appendix B. Further, Settling Parties agree that an RTP rate design based on wholesale energy prices from the CAISO markets can be explored by parties in SCE's 2021 GRC Phase 2 proceeding, assuming the new CSRP billing system is in place (when billing system implementation issues would not preclude this type of rate design).

G. 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 rate includes a nominal Customer Charge, Energy Charges, and generation TRD Charges, with no recovery of Distribution Design Demand charges in Energy or FRD Charges. The additional meter and service connection are installed in accordance with the Added Facilities provisions of SCE's Rule 2. This schedule shall be retained with adjustments to charges that are consistent with other schedules in the TOU-8 rate class.

H. 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.

I. Demand Response Credits (APS and BIP)

Rate structures and rate designs associated with SCE's demand response programs, *e.g.*, BIP and APS, shall follow the respective program budget schedules adopted in D.17-12-003. BIP credits will continue to be provided based on the difference between the customer's summer and winter average on- and mid-peak demand and firm service level, where the average on- and mid-peak demands, in each season, are calculated by dividing the kWh usage in the period by the number of hours in the period. Illustrative rates are included in Appendix B.

J. Storage-Specific Rates

No rates specifically applicable only to customers who install BTM energy storage systems are adopted as part of this Agreement. However, SCE shall file an RDW application no later than Q4 2019 that includes the consideration of storage-specific rates that incorporate the conversion of distribution costs from a monthly maximum demand charge to a daily peak demand charge. SCE is not obligated to propose or support such a design in its application, and may consider alternate rate structures. The targeted implementation of any rates adopted as part of this RDW application shall be late 2020, assuming CSRP is fully implemented, when billing system issues would not make implementation of this type of rate design structure difficult.

K. Implementing Future Revenue Changes in Rates

As described in the RA Settlement Agreement,[16] 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-D, TOU-GS-3-D, and Schedule TOU-8-Sec-D, 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 within each rate class. 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

---

[16] *See* Paragraph 4.B.7 of the RA Settlement Agreement.

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 within each rate class.

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, 2019.

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 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 2018 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. <u>Compromise of Disputed Claims</u>

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. <u>Non-Precedential</u>

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.

The Settling Parties expressly recognize that each Party may advocate a position that is inconsistent with this Agreement in Phase 2 of SCE's 2021 GRC, or earlier if invited to do so by the Commission in, for example, a relevant Rulemaking proceeding.

12. <u>Previous Communications</u>

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. Non-Waiver

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. Effect of Subject Headings

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

15. Governing Law

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. Number of Originals

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: August 3, 2018, SOUTHERN CALIFORNIA EDISON COMPANY

/s/ Ronald O. Nichols

By: Ronald O. Nichols
Title: President

Dated: August 3, 2018 FEDERAL EXECUTIVE AGENCIES

/s/ Rita M. Liotta

By: Rita M. Liotta
Title: Counsel

Dated: August 3, 2018

CALIFORNIA MANUFACTURERS & TECHNOLOGY ASSOCIATION

/s/ Ronald Liebert

By: Ronald Liebert
Title: Attorney

Dated: August 3, 2018

ENERGY USERS FORUM

/s/ Carolyn Kehrein

By: Carolyn Kehrein
Title: Consultant

Dated: August 3, 2018

CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION

/s/ Nora Sheriff

By: Nora Sheriff
Title: Counsel

Dated: August 3, 2018

SOLAR ENERGY INDUSTRIES ASSOCIATION

/s/ Sean Gallagher

By: Sean Gallagher
Title: Vice President of State Affairs

Dated: August 3, 2018

ENERGY PRODUCERS AND USERS COALITION

/s/ Katy Morsony

By: Katy Morsony
Title: Counsel

Dated: August 3, 2018

DIRECT ACCESS CUSTOMER COALITION

/s/ Dan Douglas

By: Dan Douglas
Title: Counsel

Dated: August 3, 2018

CALIFORNIA SOLAR AND STORAGE ASSOCIATION

/s/ Brad Heavner

By: Brad Heavner
Title: Policy Director

Appendix A

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

Issue	Current Treatment (*i.e.*, 2015 GRC Settled Position)	SCE	CLECA	EPUC	FEA	DACC	SEIA	CALSSA	2018 GRC Settled Position
Option D Eligibility for TOU-GS-2 and TOU-GS-3 (<500 kW) (Base Rate)	• C&I customers with demands of >20 kW to 500 kW, but otherwise no eligibility restrictions	• C&I customers with demands of >20 kW to 500 kW, but otherwise no eligibility restrictions	Not Addressed	Not Addressed	Not Addressed	Not Addressed	Not Addressed	Not Addressed	• Adopt SCE's uncontested proposal to maintain existing eligibility requirements
Option D Rate Design for TOU-GS-2 and TOU-GS-3 (<500 kW) (Base Rate)	• Offer Option B as the base rate; includes Customer Charge, TOU Energy Charges, TRD Charge and FRD Charge	• Propose to offer Option D as the replacement for Option B; continues to include Customer Charge, TOU Energy Charges, TRD Charges (new distribution TRD) and FRD Charge • Customer Charge: ~\$110/mo (TOU-GS-2) and ~\$266 (TOU-GS-3), adjusted to recover a portion (first 50 kVA) of the FLT costs in the grid distribution demand charge • Generation Energy: recovered via TOU Energy Charges • Generation Capacity: recovered via a combination of TOU Energy Charges and TRD Charges • Distribution Peak: recovered via a combination of TOU cent-per-kWh Energy Charges (50%) with balance recovered via new	Not Addressed	Not Addressed	Not Addressed	• SCE's proposed rate design changes are complex; Commission should show caution and restraint in approving major rate design changes	• Strongly supports the direction of SCE's proposed changes – more time-dependent allocation of distribution costs; concurs with SCE that allocation of coincident peak distribution costs to the TOU demand charges in Option D rates should be mitigated to reduce bill impacts / smoother transition but disagrees that coincident-peak-related distribution costs should be recovered via noncoincident demand charge • Proposes own Option D rates – most of the differences result from alternate functionalization of marginal distribution costs into coincident peak (recovered via mitigated on-peak and mid-peak demand charges), noncoincident peak (recovered via	Not Addressed	• Offer a modified Option D based on settled rate design that incorporates: ○ Updated TOU periods; ○ Customer Charge: ~\$125.25 (TOU-GS-2) and ~\$307 (TOU-GS-3) ○ For distribution, settled DDMC value; summer on-peak TRD Charge that recovers summer on, mid- and 5% of off-peak capacity cost; winter mid-peak TRD charge that recovers all winter peak capacity cost; flat cent-per-kWh Energy Charges to recover 95% of summer off-peak capacity costs; and use of FRD Charge to recover grid-related costs ○ For generation, use SCE's proposal

Issue	Current Treatment (*i.e.*, 2015 GRC Settled Position)	SCE	CLECA	EPUC	FEA	DACC	SEIA	CALSSA	2018 GRC Settled Position
		TRD Charges and FRD Charge • Distribution Grid: recovered via an FRD Charge					maximum noncoincident demand charge) and non-peak (flat energy rates); also uses ORA's PLRF proposal; rate design results in a significant reduction in noncoincident demand charge		
Option D Eligibility for TOU-8 (>500 kW) (Base Rate)	• C&I customers with demands >500 kW with the exception of certain large water pumping and agricultural customers, but otherwise no eligibility restrictions	• C&I customers with demands >500 kW with the exception of certain large water pumping and agricultural customers, but otherwise no eligibility restrictions	Support	Not Addressed	Not Addressed	Not Addressed	Not Addressed	Not Addressed	• Adopt SCE's uncontested proposal to maintain existing eligibility requirements
Option D Rate Design for TOU-8 (>500 kW) (Base Rate)	• Offer Option B as the base rate; includes Customer Charge, TOU Energy Charges, TRD Charge and FRD Charge	• Propose to offer Option D as the replacement for Option B; continues to include Customer Charge, TOU Energy Charges, TRD Charges (new distribution TRD) and FRD Charge • Customer Charge: establish at full marginal cost-based level adjusted to recover a portion (first 50 kVA) of the FLT costs in the grid distribution demand charge • Generation Energy: recovered via TOU Energy Charges • Generation Capacity: recovered via a	• Proposed recovering generation capacity costs in time-related demand charges with mitigation of bill impacts through some recovery in TOU energy charges. Opposed the portion of SCE's testimony that proposed to recover some of the coincident distribution capacity costs via distribution energy charges and some of the TOU energy smoothing SCE did for peak distribution (not cost-based) • Propose alternate Option D rates that differs from SCE's proposal in two ways:	• Opposes SCE's proposal to recover 50% of distribution peak capacity costs via energy charges – not cost-based and detrimental to high load factor customers • Propose alternate Option D rates that collect capacity cost via capacity (demand) charges	• Opposes SCE's proposal to recover 50% of distribution peak capacity costs via energy charges – not cost-based and detrimental to high load factor customers • Propose alternate Option D rates that collect capacity cost via capacity (demand) charges	• SCE's proposed rate design changes are complex; Commission should show caution and restraint in approving major rate design changes	• Strongly supports the direction of SCE's proposed changes – more time-dependent allocation of distribution costs; concurs with SCE that allocation of coincident peak distribution costs to the TOU demand charges in Option D rates should be mitigated to reduce bill impacts / smoother transition but disagrees that coincident-peak-related distribution costs should be recovered via noncoincident demand charge • Proposes own Option D rates for TOU-8-SEC and TOU-8-PRI –	Not Addressed	<u>TOU-8-SEC / TOU-8-PRI</u> • Offer a modified Option D based on settled rate design that incorporates: ○ Updated TOU periods; ○ Customer Charge: *See Appendix B* ○ For distribution, settled DDMC value; summer on-peak TRD Charge that recovers summer on, mid- and 5% of off-peak capacity cost; winter mid-peak TRD charge that recovers all winter peak capacity cost; flat cent-per-kWh Energy Charges to recover 95% of summer off-peak capacity costs; and use of FRD Charge to recover grid-related costs

Issue	Current Treatment (*i.e.*, 2015 GRC Settled Position)	SCE	CLECA	EPUC	FEA	DACC	SEIA	CALSSA	2018 GRC Settled Position
		combination of TOU Energy Charges and TRD Charges • Distribution Peak: recovered via a combination of TOU cent-per-kWh Energy Charges (50%), with balance recovered via new TRD Charges and FRD Charge • Distribution Grid: recovered via an FRD Charge	(1) use CLECA's uncapped revenue allocation and (2) recover all distribution capacity costs in demand charges – peak capacity costs are recovered via TRD Charges and grid capacity costs are recovered via an FRD Charge (no distribution revenue is recovered in energy charges).				most of the differences result from alternate functionalization of marginal distribution costs into coincident peak (recovered via mitigated on-peak and mid-peak demand charges), noncoincident peak (recovered via maximum noncoincident demand charge) and non-peak (flat energy rates); also uses ORA's PLRF proposal; rate design results in a significant reduction in noncoincident demand charge		○ For generation, use settled GCMC value with SCE's proposal <u>TOU-8-SUB</u> • Offer a modified Option D based on settled rate design that incorporates: ○ Updated TOU periods; ○ Customer Charge: *See Appendix B* ○ For distribution, settled DDMC value; summer on-peak TRD Charge that recovers summer on-peak capacity cost; winter mid-peak TRD charge that recovers all winter mid-peak capacity cost; FRD Charge that recovers grid-related costs and summer mid- and off-peak and winter off- and SOP-peak capacity costs; no distribution costs recovered via Energy Charges ○ For generation, use settled GCMC value with SCE's proposal
Option E Eligibility for TOU-GS-2 and TOU-GS-3 (<500 kW) (Base Rate)	• C&I customers with demands of >20 kW to 500 kW • Technology restrictions for customers on Option R, including a 400 MW participation cap (inclusive of all applicable rate classes)	• C&I customers with demands of >20 kW to 500 kW, but otherwise no eligibility restrictions	Not Addressed	Not Addressed	Not Addressed	• Supports SCE's new, more open Option E – offers opportunities for DA customers to better manage their loads and electric costs	• Supports SCE's proposal to allow Option E to be technology-agnostic and available to all customers	Not Addressed	• Adopt SCE's proposal that includes no eligibility restrictions • Exempt customers with DER technologies from Standby

Issue	Current Treatment (*i.e.*, 2015 GRC Settled Position)	SCE	CLECA	EPUC	FEA	DACC	SEIA	CALSSA	2018 GRC Settled Position
Option E Rate Design for TOU-GS-2 and TOU-GS-3 (<500 kW) (Base Rate)	• Offer Options A and R as optional rates that include a Customer Charge, TOU Energy Charges and an FRD Charge (but no TRD Charges)	• Propose to offer Option E as the replacement for Options A and R (maintain no TRD structure) • Customer Charge: ~$110/mo (TOU-GS-2) and ~$266/mo (TOU-GS-3), adjusted to recover a portion (first 50 kVA) of the FLT costs in the grid distribution demand charge • Generation Energy: recovered via TOU Energy Charges • Generation Capacity: recovered entirely via TOU cent-per-kWh Energy Charges • Distribution Peak: recovered entirely via cent-per-kWh Energy Charge • Distribution Grid: recovered via FRD Charge	Not Addressed	Not Addressed	Not Addressed	• Supports SCE's new, more open Option E – offers opportunities for DA customers to better manage their loads and electric costs	• Strongly supports the direction of SCE's proposed changes – more time-dependent allocation of distribution costs • Proposes own Option E rates – most of the differences result from alternate functionalization of marginal distribution costs into coincident peak (recovered via energy charges), noncoincident peak (recovered via maximum noncoincident demand charge) and non-peak (flat energy rates); also uses ORA's PLRF proposal; rate design results in a significant reduction in noncoincident demand charge; rate design results in a significant reduction in noncoincident demand charge	• Not a viable option for solar or solar + storage (due to structure and updated TOU periods) • Recommends that a smaller portion of costs be recovered via peak energy charges, creating a structure with a lower differential between peak and off-peak rates	• Offer a modified Option E based on settled rate design that incorporates: ○ Updated TOU periods; ○ Customer Charge: ~$125.25 (TOU-GS-2) and ~$307 (TOU-GS-3) ○ For distribution, recover 60% of revenues (excluding the customer charge revenues) via TOU Energy Charges using the PLRFs proposed by ORA in Opening Testimony, 30% via an FRD Charge and 10% via flat Energy Charges ○ For generation, incorporate a TRD Charge set at 25% of the Standby Backup Demand Charge with the balance of revenues recovered via TOU Energy Charges • SCE to study the appropriate level for the TRD Charge and include results as part of its 2021 GRC Phase 2 application
Option E Eligibility for TOU-8 (>500 kW) (Base Rate)	• Option A eligibility limited to PLS, cold-ironing and eligible ZEVs • Option R eligibility limited to customers w/ annual peak demands not exceeding 4 MW who install solar, wind, fuel cells or	• C&I customers with demands >500 kW with the exception of certain large water pumping and agricultural customers, but otherwise no eligibility restrictions	• Option E rates should not be open to all customers. Oppose SCE's proposal to give all customers the option, including low load factor customers.	• Opposes Option E rates due to likely revenue erosion from low load factor customers (who don't need to have an eligible technology to qualify)	• Opposes Option E rates due to likely revenue erosion from low load factor customers (who don't need to have an eligible technology to qualify)	• Supports SCE's new, more open Option E – offers opportunities for DA customers to better manage their loads and electric costs	• Supports SCE's proposal to allow Option E to be technology-agnostic and available to all customers	Not Addressed	• Eligibility limited to customers with qualifying technologies, which include technologies currently eligible for TOU-8, Options A and R and BTM paired storage (solar+storage) and standalone storage • 250 MW customer participation cap for customers w/ DER

Issue	Current Treatment (*i.e.*, 2015 GRC Settled Position)	SCE	CLECA	EPUC	FEA	DACC	SEIA	CALSSA	2018 GRC Settled Position
	other onsite DERs as defined by the CSI or SGIP; eligible systems must have a net renewable generating capacity ≥15% of the customer's annual peak demand as recorded over the previous 12 months • 400 MW participation cap on Option R (inclusive of all applicable rate classes)								technologies (i.e., cap not does apply to customers with PLS, cold ironing or eligible ZEVs, which are the existing technologies that qualify for TOU-8, Option A) ○ For DERs, capacity counted toward cap is based on the system's AC nameplate rating (consistent w/ value used to determine capacity counted toward current Option R cap) ○ For paired storage systems, count the larger of the AC solar capacity or the discharge capacity of the storage unit (but not both) ○ Cap is incremental to existing Option R cap ○ SCE to file information-only advice letters (ALs) to report on the progress toward the 250 MW cap; frequency will be every 50 MW of allocated capacity (based on signed interconnection agreement data and date) until 200 MW is reached, at which time SCE will file ALs monthly until the 250 MW cap is reached (the monthly filings will include addl data about projects still pending PTO)

Issue	Current Treatment (*i.e.*, 2015 GRC Settled Position)	SCE	CLECA	EPUC	FEA	DACC	SEIA	CALSSA	2018 GRC Settled Position
									• For DERs (excluding standalone storage), system must have a net renewable generating capacity equal to or greater than 15% of the customer's annual peak demand, as recorded over the previous 12 months ○ For BTM standalone storage, system must have a minimum discharge capacity equal to or greater than 20% of the customer's annual peak demand, as recorded over the previous 12 months • Limited to customers with annual peak demands not exceeding 5 MW • Exempt participating customers from Standby
Option E Rate Design for TOU-8 (>500 kW) (Base Rate)	• Offer Options A and R as optional rates that include a Customer Charge, TOU Energy Charges and an FRD Charge (but no TRD Charges)	• Propose to offer Option E as the replacement for Options A and R (maintain no TRD structure) • Customer Charge: establish at full marginal cost-based level adjusted to recover a portion (first 50 kVA) of the FLT costs in the grid distribution demand charge • Generation Energy: recovered via TOU Energy Charges • Generation Capacity: recovered entirely	• Oppose SCE's proposed recovery of capacity costs via energy charges, except to a limited extent to mitigate bill impacts for certain groups of customers – without demand charges, customers w/ low load factors can impose substantial fixed costs on the system and avoid paying fully for those capacity costs because their usage is low; best way to recover generation costs is via a mixture of coincident demand	• Opposes Option E rates due to likely revenue erosion from low load factor customers (who don't need to have an eligible technology to qualify)	• Opposes Option E rates due to likely revenue erosion from low load factor customers (who don't need to have an eligible technology to qualify)	• Supports SCE's new, more open Option E – offers opportunities for DA customers to better manage their loads and electric costs	• Strongly supports the direction of SCE's proposed changes – more time-dependent allocation of distribution costs • Proposes own Option E rates for TOU-8-SEC and TOU-8-PRI – most of the differences result from alternate functionalization of marginal distribution costs into coincident peak (recovered via energy charges), noncoincident peak (recovered via maximum noncoincident demand charge) and non-peak (flat energy rates); also	• Same as <500 kW	<u>TOU-8-SEC / TOU-8-PRI</u> • Offer a modified Option E based on settled rate design that incorporates: ○ Updated TOU periods; ○ Customer Charge: *See Appendix B* ○ For distribution, recover 60% of revenues (excluding the customer charge revenues) via TOU Energy Charges using the PLRFs proposed by ORA in Opening Testimony, 30% via an FRD Charge and 10% via flat Energy Charges ○ For generation, use a settled GCMC and incorporate a TRD

Issue	Current Treatment (*i.e.*, 2015 GRC Settled Position)	SCE	CLECA	EPUC	FEA	DACC	SEIA	CALSSA	2018 GRC Settled Position
		via TOU cent-per-kWh Energy Charges • Distribution Peak: recovered entirely via cent-per-kWh Energy Charge • Distribution Grid: recovered via FRD Charge	charges and TOU-varying energy rates				uses ORA's PLRF proposal; rate design results in a significant reduction in noncoincident demand charge		Charge set at 25% of the Standby Backup Demand Charge with the balance of revenues recovered via TOU Energy Charges <u>TOU-8-SUB</u> • Offer a modified Option E based on settled rate design that incorporates: ○ Updated TOU periods; ○ Customer Charge: *See Appendix B* ○ For distribution, use a settled DDMC value with a peak/grid split based on MCRR (78/22 peak/grid); Grid-related costs (22%) are recovered via an FRD charge and peak-related costs (78%) are recovered via TOU Energy Charges using the PLRFs proposed by ORA in Opening Testimony ○ For generation, use a settled GCMC and incorporate a TRD Charge set at 25% of the Standby Backup Demand Charge with the balance of revenues recovered via TOU Energy Charges • SCE to study the appropriate level for the TRD Charge and include results as part of its 2021 GRC Phase 2 application

Issue	Current Treatment (*i.e.*, 2015 GRC Settled Position)	SCE	CLECA	EPUC	FEA	DACC	SEIA	CALSSA	2018 GRC Settled Position
Storage-Specific Rates	N/A	Did Not Propose	Not Addressed	Not Addressed	Not Addressed	Not Addressed	• Proposes Option S rates for customers who install a certain amount of on-site, SGIP-eligible storage • Identical to Option E rates, except that maximum demand charge for distribution costs would be converted to a daily peak demand charge, applicable during SCE's on- and mid-peak periods and designed to recover the same class revenues as the existing monthly demand charge	Not Addressed	• SCE to file an RDW application in late 2019 that includes consideration of (but that does not obligate SCE to support) an Option S structure as proposed by SEIA (*i.e.*, use of daily demand charges) with a targeted implementation date of late 2020 (assuming the CSRP project is complete)
Real Time Pricing (RTP)	• Offer menus of hourly prices based on 9 day-types; pricing menu determined one day in advance based on temperature at the Los Angeles Civic Center; hourly RTP rates designed to recover the generation rev req	• Incorporate rate design updates proposed in 2016 RDW (7 day-type menus instead of 9) • Use updated LOLE study to determine seasonal hourly pricing profiles for energy and capacity; distribution charges updated based on Option D proposals described above	• Doesn't object to RTP changes proposed in 2016 RDW • Recommend that SCE develop the capability in its billing system to pass through wholesale process for retail sales and that it work with parties to develop such a pricing option for its 2021 GRC Phase 2 application	Not Addressed	Not Addressed	Not Addressed	Not Addressed	• Daytime energy charges on RTP rates are so low that investment in solar PV systems is event less viable than under Option E; solar + storage also not viable	• Incorporate the changes adopted in the 2016 RDW and use a class revenue-neutral rate design • Specify that rate design based on wholesale energy prices from the CAISO markets can be explored by parties in SCE's 2021 GRC Phase 2 when the CSRP system is in place
Standby Rates (Schedule S, TOU-8-S, TOU-8-RTP-S)	• New Standby algorithm adopted with the addition of a Phase-In and Confirmation Review process	• No structural changes proposed for Schedule S • For TOU-8-S and TOU-8-RTP-S, recover distribution grid costs via an FRD Charge and distribution peak costs via a TRD	Not Addressed	Not Addressed	• Propose alternate TOU-8-S rates that collect capacity cost via capacity (demand) charges	Not Addressed	Not Addressed	Not Addressed	• Adopt SCE's uncontested proposals for Schedule S • Incorporate the settled Option D rate design described above for TOU-8-S and TOU-8-RTP-S (in addition to the updated RTP design described above)

Issue	Current Treatment (*i.e.*, 2015 GRC Settled Position)	SCE	CLECA	EPUC	FEA	DACC	SEIA	CALSSA	2018 GRC Settled Position
		Charge (CRC will continue to be recovered via a $-per-month charge applied to Standby Demand), with supplemental and back-up TRD Charges set at their full EPMC levels and applied in both summer and winter • Continue to apply the Standby algorithm adopted in the 2015 GRC Phase 2 to determine the Standby Demand and Supplemental Contract Capacity							
Reliability Back-Up Service (TOU-8-RBU)	• Provide large customers w/ an additional service connection to be used solely for reliability or back-up purposes • Includes a small Customer Charge and no other distribution design demand charges (small since most distribution costs are billed as Added Facilities), TOU Energy Charges & a TRD Charge	• Same as Current Treatment but with updated Customer Charge, TOU Energy and TRD Charge to reflect marginal-cost based changes made to Option D (as described above)	Not Addressed	Not Addressed	Not Addressed	Not Addressed	Not Addressed	Not Addressed	• Adopt SCE's uncontested proposal
EV Rates (TOU-EV-4/TOU-EV-8 & TOU-EV-	• Adopted TOU-EV-4 as an optional EV rate for customers with demands below 200 kW	• Updated to reflect new TOU periods and the bifurcated distribution grid and peak rate structures, with the distribution	Not Addressed	Not Addressed	Not Addressed	Not Addressed	Not Addressed	Not Addressed	• Adopt SCE's uncontested proposal for the updates to the TOU-EV-4 and TOU-EV-8 rate designs (but will be replaced by TOU-EV-6 and TOU-

Issue	Current Treatment (*i.e.*, 2015 GRC Settled Position)	SCE	CLECA	EPUC	FEA	DACC	SEIA	CALSSA	2018 GRC Settled Position
6/TOU-EV-9)	• Included distribution charge provision for customers with EV and non-EV accounts on the same premises (EV customer is not responsible for paying the FRD charges registered on the EV account if the non-EV account's monthly maximum demand is higher than the monthly maximum demand registered on the EV account's meter)	peak-capacity costs recovered via TOU Energy Charges • Grandfather existing distribution charge provision for customers that have an EV account located on the same premises as the non-EV host account so that the EV customer is not responsible for paying the FRD charges registered on the EV account if the non-EV account's monthly maximum demand is higher than the monthly maximum demand registered on the EV account's meter							EV-9, respectively, as adopted in D.18-05-040) • Adopt SCE's distribution charge grandfathering provision
GS-APS-E	• Offer an interruptible summer discount plan rate for commercial customers	• No structural changes proposed; credit levels based on program budget schedule adopted in D.17-12-003	Not Addressed	Not Addressed	Not Addressed	Not Addressed	Not Addressed	Not Addressed	• Adopt SCE's uncontested proposal
TOU-BIP	• Credits that are provided for non-firm service set at $108 per kW-year GCMC	• No structural changes proposed (using updated TOU periods) beyond those included in A.17-01-018; credit levels based on program budget schedule adopted in D.17-12-003	Not Addressed	Not Addressed	Not Addressed	Not Addressed	Not Addressed	Not Addressed	• Adopt SCE's uncontested proposal – continue to provide BIP credits based on the difference between the customer's average on- and mid-peak demand and firm service level, where the average on- and mid-peak demands are calculated by dividing the kWh usage in the period by the # of hours in the period

Appendix B

Illustrative Medium and Large Power Rate Group Rates

	January 2018 Rates			Proposed 2018 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
GS-2 (Non TOU Rate)									
Energy Charge - $/kWh									
Summer	0.02201	0.06029	0.08230	0.05711	0.05177	0.10888	159.5%	-14.1%	32.3%
Winter	0.02201	0.05113	0.07314	0.03870	0.05490	0.09360	75.8%	7.4%	28.0%
Customer Charge - $/month	231.17	0.00	231.17	125.25		125.25	-45.8%		-45.8%
Facilities Related Demand Charge - $/kW	15.78	0.00	15.78	11.41		11.41	-27.7%		-27.7%
Summer Time Related Demand Charge - $/kW	0.00	21.03	21.03	0.00	12.99	12.99		-38.2%	-38.2%
Single Phase Service - $/month	(14.88)	0.00	(14.88)	(6.80)	0.00	(6.80)	54.3%		54.3%
Voltage Discount, Facilities Related Demand - $/kW									
From 2 kV to 50 kV	(0.21)	0.00	(0.21)	(0.11)		(0.11)	47.6%		47.6%
From 51 kV to 219 kV	(6.44)	0.00	(6.44)	(4.26)		(4.26)	33.9%		33.9%
220 kV and above	(11.16)	0.00	(11.16)	(7.49)		(7.49)	32.9%		32.9%
Voltage Discount, Time-Related Demand - $/kW									
From 2 kV to 50 kV	0.00	(0.56)	(0.56)	0.00	(0.22)	(0.22)		60.7%	60.7%
From 51 kV to 219 kV	0.00	(1.55)	(1.55)	0.00	(0.60)	(0.60)		61.3%	61.3%
220 kV and above	0.00	(1.57)	(1.57)	0.00	(0.61)	(0.61)		61.1%	61.1%
Voltage Discount, Energy - $/kWh									
From 2 kV to 50 kV	0.00000	(0.00101)	(0.00101)	(0.00034)	(0.00091)	(0.00125)		9.9%	-23.8%
From 51 kV to 219 kV	0.00000	(0.00230)	(0.00230)	(0.00939)	(0.00202)	(0.01141)		12.2%	-396.1%
220 kV and above	0.00000	(0.00232)	(0.00232)	(0.02305)	(0.00204)	(0.02509)		12.1%	-981.5%
Bill Limiter (GS-1 to GS-2) - %	20.89%	79.11%	100.00%	20.89%	79.11%	100.00%	0.0%	0.0%	0.0%
California Climate Credit - $/kWh/Meter/Month	(0.00484)	0.00000	(0.00484)	(0.00458)	0.00000	(0.00458)	5.4%		5.4%
TOU-GS-2-D									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.02201	0.10146	0.12347	0.02876	0.07739	0.10615	30.7%	-23.7%	-14.0%
Mid-peak	0.02201	0.05845	0.08046	0.02876	0.06960	0.09836	30.7%	19.1%	22.2%
Off-Peak	0.02201	0.03546	0.05747	0.02876	0.04443	0.07319	30.7%	25.3%	27.4%
Winter Season									
Mid-peak	0.02201	0.05465	0.07666	0.02876	0.05836	0.08712	30.7%	6.8%	13.6%
Off-Peak	0.02201	0.04298	0.06499	0.02876	0.04899	0.07775	30.7%	14.0%	19.6%
Super-Off-Peak				0.02876	0.03140	0.06016			
Customer Charge - $/month	228.58	0.00	228.58	125.25		125.25	-45.2%		-45.2%
Facilities Related Demand Charge - $/kW	15.89	0.00	15.89	11.41		11.41	-28.2%		-28.2%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	0.00	19.89	19.89	9.56	17.25	26.81		-13.3%	34.8%
Mid-Peak	0.00	3.88	3.88	0.00	0.00	0.00		-100.0%	-100.0%
Winter Season									
Mid-Peak				3.45	3.53	6.98			
Single Phase Service - $/month	(12.15)	0.00	(12.15)	(6.80)	0.00	(6.80)	44.0%		44.0%
Voltage Discount, Facilities Related Demand - $/kW									
From 2 kV to 50 kV	(0.21)	0.00	(0.21)	(0.11)		(0.11)	47.6%		47.6%
From 51 kV to 219 kV	(6.98)	0.00	(6.98)	(4.26)		(4.26)	39.0%		39.0%
220 kV and above	(11.69)	0.00	(11.69)	(7.49)		(7.49)	35.9%		35.9%
Voltage Discount, Time-Related Demand - $/kW									
From 2 kV to 50 kV	0.00	(0.38)	(0.38)	(0.09)	(0.15)	(0.24)		60.5%	36.8%
From 51 kV to 219 kV	0.00	(1.06)	(1.06)	(2.35)	(0.41)	(2.76)		61.3%	-160.4%
220 kV and above	0.00	(1.07)	(1.07)	(5.76)	(0.41)	(6.17)		61.7%	-476.6%
Voltage Discount, Energy - $/kWh									
From 2 kV to 50 kV	0.00000	(0.00140)	(0.00140)	(0.00009)	(0.00080)	(0.00089)		42.9%	36.4%
From 51 kV to 219 kV	0.00000	(0.00311)	(0.00311)	(0.00255)	(0.00176)	(0.00431)		43.4%	-38.6%
220 kV and above	0.00000	(0.00314)	(0.00314)	(0.00627)	(0.00178)	(0.00805)		43.3%	-156.4%
TOU Rate Meter Charge - $/month									
TOU-RTEM	71.01	0.00	71.01	17.48	0.00	17.48	-75.4%		-75.4%
California Climate Credit - $/kWh/Meter/Month	(0.00484)	0.00000	(0.00484)	(0.00458)	0.00000	(0.00458)	5.4%		5.4%

	January 2018 Rates			Proposed 2018 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-GS-2-E									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.03532	0.35987	0.39519	0.15453	0.30942	0.46395	337.5%	-14.0%	17.4%
Mid-peak	0.03532	0.10070	0.13602	0.09023	0.06960	0.15983	155.5%	-30.9%	17.5%
Off-Peak	0.03532	0.03545	0.07077	0.06544	0.04443	0.10987	85.3%	25.3%	55.2%
Winter Season									
Mid-peak	0.03532	0.05464	0.08996	0.05090	0.09513	0.14603	44.1%	74.1%	62.3%
Off-Peak	0.03532	0.04297	0.07829	0.03256	0.04899	0.08155	-7.8%	14.0%	4.2%
				0.04203	0.03140	0.07343			
Customer Charge - $/month	228.58	0.00	228.58	125.25		125.25	-45.2%		-45.2%
Facilities Related Demand Charge - $/kW	12.00	0.00	12.00	8.19	0.00	8.19	-31.8%		-31.8%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak				0.00	3.46	3.46			
Mid-Peak				0.00	0.00	0.00			
Winter Season									
Mid-Peak				0.00	0.74	0.74			
Single Phase Service - $/month	(12.15)	0.00	(12.15)	(6.80)	0.00	(6.80)	44.0%		44.0%
Voltage Discount, Facilities Related Demand - $/kW									
From 2 kV to 50 kV	(0.14)	0.00	(0.14)	(0.06)	0.00	(0.06)	57.1%		57.1%
From 51 kV to 219 kV	(4.65)	0.00	(4.65)	(2.43)	0.00	(2.43)	47.7%		47.7%
220 kV and above	(7.80)	0.00	(7.80)	(4.27)	0.00	(4.27)	45.3%		45.3%
Voltage Discount, Time Related Demand - $/kW									
From 2 kV to 50 kV				0.00	(0.03)	(0.03)			
From 51 kV to 219 kV				0.00	(0.08)	(0.08)			
220 kV and above				0.00	(0.08)	(0.08)			
Voltage Discount, Energy - $/kWh									
From 2 kV to 50 kV	(0.00024)	(0.00189)	(0.00213)	(0.00052)	(0.00116)	(0.00168)	-116.7%	38.6%	21.1%
From 51 kV to 219 kV	(0.00795)	(0.00449)	(0.01244)	(0.01576)	(0.00275)	(0.01851)	-98.2%	38.8%	-48.8%
220 kV and above	(0.01332)	(0.00454)	(0.01786)	(0.03429)	(0.00277)	(0.03706)	-157.4%	39.0%	-107.5%
TOU Rate Meter Charge - $/month									
TOU-RTEM	71.01	0.00	71.01	17.48	0.00	17.48	-75.4%		-75.4%
California Climate Credit - $/kWh/Meter/Month	(0.00484)	0.00000	(0.00484)	(0.00458)	0.00000	(0.00458)	5.4%		5.4%

	January 2018 Rates			Proposed 2018 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-GS-2-D-CPP									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.02201	0.10146	0.12347	0.02876	0.07739	0.10615	30.7%	-23.7%	-14.0%
Mid-peak	0.02201	0.05845	0.08046	0.02876	0.06960	0.09836	30.7%	19.1%	22.2%
Off-Peak	0.02201	0.03546	0.05747	0.02876	0.04443	0.07319	30.7%	25.3%	27.4%
Winter Season									
Mid-peak	0.02201	0.05465	0.07666	0.02876	0.05836	0.08712	30.7%	6.8%	13.6%
Off-Peak	0.02201	0.04298	0.06499	0.02876	0.04899	0.07775	30.7%	14.0%	19.6%
Super-Off-Peak				0.02876	0.03140	0.06016			
Customer Charge - $/month	228.58	0.00	228.58	125.25		125.25	-45.2%		-45.2%
Single Phase Service - $/month	(12.15)	0.00	(12.15)	(6.80)		(6.80)	44.0%		44.0%
Facilities Related Demand Charge - $/kW	15.89	0.00	15.89	11.41	0.00	11.41	-28.2%		-28.2%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	0.00	19.89	19.89	9.56	17.25	26.81		-13.3%	34.8%
Mid-Peak	0.00	3.88	3.88	0.00	0.00	0.00		-100.0%	-100.0%
Winter Season									
Mid-Peak				3.45	3.53	6.98			
Voltage Discount, Facilities Related Demand - $/kW									
From 2 kV to 50 kV	(0.21)	0.00	(0.21)	(0.11)	0.00	(0.11)	47.6%		47.6%
Above 50 kV but below 220 kV	(6.98)	0.00	(6.98)	(4.26)	0.00	(4.26)	39.0%		39.0%
At 220 kV	(11.69)	0.00	(11.69)	(7.49)	0.00	(7.49)	35.9%		35.9%
Voltage Discount, Time-Related Demand - $/kW									
From 2 kV to 50 kV	0.00	(0.38)	(0.38)	(0.09)	(0.15)	(0.24)		60.5%	36.8%
Above 50 kV but below 220 kV	0.00	(1.06)	(1.06)	(2.35)	(0.41)	(2.76)		61.3%	-160.4%
At 220 kV	0.00	(1.07)	(1.07)	(5.76)	(0.41)	(6.17)		61.7%	-476.6%
Voltage Discount, Energy - $/kWh									
From 2 kV to 50 kV	0.00000	(0.00140)	(0.00140)	(0.00009)	(0.00080)	(0.00089)		42.9%	36.4%
Above 50 kV but below 220 kV	0.00000	(0.00311)	(0.00311)	(0.00255)	(0.00176)	(0.00431)		43.4%	-38.6%
At 220 kV	0.00000	(0.00314)	(0.00314)	(0.00627)	(0.00178)	(0.00805)		43.3%	-156.4%
TOU Rate Meter Charge - $/month									
TOU-RTEM	71.01	0.00	71.01	17.48	0.00	17.48	-75.4%		-75.4%
CPP Event Energy Charge - $/kWh	0.00000	0.68727	0.68727	0.00000	0.40000	0.40000		-41.8%	-41.8%
Summer CPP Non-Event Credit On-Peak Demand Credit - $/kW	0.00	(5.38)	(5.38)	0.00	(3.42)	(3.42)		36.4%	36.4%
California Climate Credit - $/kWh/Meter/Month	(0.00484)	0.00000	(0.00484)	(0.00458)	0.00000	(0.00458)	5.4%		5.4%

	January 2018 Rates			Proposed 2018 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-GS-2-RTP									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.02201	Variable*	Variable*	0.02876	Variable*	Variable*	30.7%		
Mid-peak				0.02876	Variable*	Variable*			
Off-Peak				0.02876	Variable*	Variable*			
Winter Season									
Mid-peak				0.02876	Variable*	Variable*			
Off-Peak				0.02876	Variable*	Variable*			
Super-Off-Peak				0.02876	Variable*	Variable*			
Customer Charge - $/month	228.58	0.00	228.58	125.25		125.25	-45.2%		-45.2%
Single Phase Service - $/month	(12.15)	0.00	(12.15)	(6.80)		(6.80)	44.0%		44.0%
Facilities Related Demand Charge - $/kW	15.89	0.00	15.89	11.41		11.41	-28.2%		-28.2%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak				9.56	0.00	9.56			
Mid-Peak				0.00	0.00	0.00			
Voltage Discount, Facilities Related Demand - $/kW									
From 2 kV to 50 kV	(0.21)	0.00	(0.21)	(0.11)		(0.11)	47.6%		47.6%
Above 50 kV but below 220 kV	(6.98)	0.00	(6.98)	(4.26)		(4.26)	39.0%		39.0%
At 220 kV	(11.69)	0.00	(11.69)	(7.49)		(7.49)	35.9%		35.9%
Voltage Discount, Time-Related Demand - $/kW									
From 2 kV to 50 kV				(0.09)		(0.09)			
Above 50 kV but below 220 kV				(2.35)		(2.35)			
At 220 kV				(5.76)		(5.76)			
Voltage Discount, Energy - $/kWh									
From 2 kV to 50 kV	0.00000	(0.00189)	(0.00189)	(0.00009)	(0.00116)	(0.00125)		38.6%	33.9%
Above 50 kV but below 220 kV	0.00000	(0.00449)	(0.00449)	(0.00255)	(0.00275)	(0.00530)		38.8%	-18.0%
At 220 kV	0.00000	(0.00454)	(0.00454)	(0.00627)	(0.00277)	(0.00904)		39.0%	-99.1%
TOU Rate Meter Charge - $/month									
TOU-RTEM	71.01	0.00	71.01	17.48		17.48	-75.4%		-75.4%
California Climate Credit - $/kWh/Meter/Month	(0.00484)	0.00000	(0.00484)	(0.00458)	0.00000	(0.00458)	5.4%		5.4%
GS-APS (Schedules: TOU-GS-2, TOU-GS-3, or TOU-8)									
Air Conditioning Cycling Credit - $/ton/summer season month									
30% Cycling	(1.40)	0.00	(1.40)	0.00	0.00	0.00	100.0%		100.0%
40% Cycling	(1.70)	0.00	(1.70)	0.00	0.00	0.00	100.0%		100.0%
50% Cycling	(2.47)	0.00	(2.47)	0.00	0.00	0.00	100.0%		100.0%
100% Cycling	(10.02)	0.00	(10.02)	0.00	0.00	0.00	100.0%		100.0%
GS-APS-E (Schedules: TOU-GS-2, TOU-GS-3, or TOU-8)									
Air Conditioning Cycling Credit - $/ton/summer season month									
30% Cycling	(0.79)	0.00	(0.79)	(0.78)	0.00	(0.78)	1.3%		1.3%
40% Cycling	0.00	0.00	0.00	0.00	0.00	0.00			
50% Cycling	(3.92)	0.00	(3.92)	(3.92)	0.00	(3.92)	0.0%		0.0%
100% Cycling	(11.21)	0.00	(11.21)	(11.19)	0.00	(11.19)	0.2%		0.2%

	January 2018 Rates			Proposed 2018 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-EV-4									
Energy Charge - $/kWh									
Summer Season On-Peak	0.02201	0.26028	0.28229	0.15453	0.30942	0.46395	602.1%	18.9%	64.4%
Mid-Peak	0.02201	0.07397	0.09598	0.09023	0.06960	0.15983	310.0%	-5.9%	66.5%
Off-Peak	0.02201	0.03345	0.05546	0.06544	0.04443	0.10987	197.3%	32.8%	98.1%
Winter Season On-Peak	0.02201	0.07010	0.09211	0.05090	0.09513	0.14603	131.3%	35.7%	58.5%
Mid-Peak	0.02201	0.05531	0.07732	0.03256	0.04899	0.08155	47.9%	-11.4%	5.5%
Off-Peak	0.02201	0.03809	0.06010	0.04203	0.03140	0.07343	91.0%	-17.6%	22.2%
Customer Charge - $/meter/month	228.58	0.00	228.58	125.25		125.25	-45.2%		-45.2%
Facilities Related									
Demand Charge - $/kW	15.89	0.00	15.89	8.19		8.19	-48.5%		-48.5%
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	(0.21)	0.00	(0.21)	(0.06)	0.00	(0.06)	71.4%		71.4%
From 51 kV to 219 kV	(6.98)	0.00	(6.98)	(2.43)	0.00	(2.43)	65.2%		65.2%
220 kV and above	(11.69)	0.00	(11.69)	(4.27)	0.00	(4.27)	63.5%		63.5%
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	(0.00140)	(0.00140)	(0.00052)	(0.00116)	(0.00168)		17.1%	-20.0%
From 51 kV to 219 kV	0.00000	(0.00311)	(0.00311)	(0.01576)	(0.00275)	(0.01851)		11.6%	-495.2%
220 kV and above	0.00000	(0.00314)	(0.00314)	(0.03429)	(0.00277)	(0.03706)		11.8%	-1080.3%
Power Factor Adjustment - $/kVA									
Greater than 50 kV	0.47	0.00	0.47	0.54	0.00	0.54	14.9%		14.9%
50 kV or less	0.55	0.00	0.55	0.60	0.00	0.60	9.1%		9.1%
California Climate Credit - $/kWh/Meter/Month	(0.00484)	0.00000	(0.00484)	(0.00458)	0.00000	(0.00458)	5.4%		5.4%
TOU-GS-3-D									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.02114	0.10130	0.12244	0.02779	0.07327	0.10106	31.5%	-27.7%	-17.5%
Mid-peak	0.02114	0.05852	0.07966	0.02779	0.06590	0.09369	31.5%	12.6%	17.6%
Off-Peak	0.02114	0.03706	0.05820	0.02779	0.04259	0.07038	31.5%	14.9%	20.9%
Winter Season									
Mid-peak	0.02114	0.05355	0.07469	0.02779	0.05594	0.08373	31.5%	4.5%	12.1%
Off-Peak	0.02114	0.04264	0.06378	0.02779	0.04696	0.07475	31.5%	10.1%	17.2%
Super-Off-Peak				0.02779	0.03010	0.05789			
Customer Charge - $/month	462.59	0.00	462.59	307.00	0.00	307.00	-33.6%		-33.6%
Facilities Related									
Demand Charge - $/kW	18.29	0.00	18.29	12.47	0.00	12.47	-31.8%		-31.8%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	0.00	20.01	20.01	10.29	16.82	27.11		-15.9%	35.5%
Mid-Peak	0.00	3.94	3.94	0.00	0.00	0.00		-100.0%	-100.0%
Winter Season									
Mid-Peak	0.00	0.00	0.00	3.46	3.04	6.50			
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	(0.22)	0.00	(0.22)	(0.13)	0.00	(0.13)	40.9%		40.9%
From 51 kV to 219 kV	(7.31)	0.00	(7.31)	(4.93)	0.00	(4.93)	32.6%		32.6%
220 kV and above	(13.66)	0.00	(13.66)	(8.15)	0.00	(8.15)	40.3%		40.3%
Voltage Discount, Time-Related Demand - $/kW									
From 2 kV to 50 kV	0.00	(0.39)	(0.39)	(0.09)	(0.14)	(0.23)		64.1%	41.0%
From 51 kV to 219 kV	0.00	(1.07)	(1.07)	(2.46)	(0.39)	(2.85)		63.6%	-166.4%
220 kV and above	0.00	(1.08)	(1.08)	(5.92)	(0.39)	(6.31)		63.9%	-484.3%
Voltage Discount, Energy - $/kWh									
From 2 kV to 50 kV	0.00000	(0.00140)	(0.00140)	(0.00008)	(0.00079)	(0.00087)		43.6%	37.9%
From 51 kV to 219 kV	0.00000	(0.00309)	(0.00309)	(0.00229)	(0.00175)	(0.00404)		43.4%	-30.7%
220 kV and above	0.00000	(0.00312)	(0.00312)	(0.00554)	(0.00177)	(0.00731)		43.3%	-134.3%
Power Factor Adjustment - $/kVA									
Greater than 50 kV	0.47	0.00	0.47	0.54	0.00	0.54	14.9%		14.9%
50 kV or less	0.55	0.00	0.55	0.60	0.00	0.60	9.1%		9.1%

	January 2018 Rates			Proposed 2018 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-GS-3-E									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.04068	0.33215	0.37283	0.14962	0.27815	0.42777	267.8%	-16.3%	14.7%
Mid-peak	0.04068	0.09512	0.13580	0.09248	0.06590	0.15838	127.3%	-30.7%	16.6%
Off-Peak	0.04068	0.03706	0.07774	0.06133	0.04259	0.10392	50.8%	14.9%	33.7%
Winter Season									
Mid-peak	0.04068	0.05355	0.09423	0.04845	0.08442	0.13287	19.1%	57.6%	41.0%
Off-Peak	0.04068	0.04264	0.08332	0.03096	0.04696	0.07792	-23.9%	10.1%	-6.5%
Super-Off-Peak				0.03987	0.03010	0.06997			
Customer Charge - $/month	462.59	0.00	462.59	307.00	0.00	307.00	-33.6%		-33.6%
Facilities Related									
Demand Charge - $/kW	11.45	0.00	11.45	8.86	0.00	8.86	-22.6%		-22.6%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak				0.00	3.38	3.38			
Mid-Peak				0.00	0.00	0.00			
Winter Season									
Mid-Peak				0.00	0.64	0.64			
Off-Peak				0.00	0.00	0.00			
Voltage Discount, Facilities Related Demand - $/kW									
From 2 kV to 50 kV	(0.11)	0.00	(0.11)	(0.07)	0.00	(0.07)	36.4%		36.4%
From 51 kV to 219 kV	(3.65)	0.00	(3.65)	(2.75)	0.00	(2.75)	24.7%		24.7%
220 kV and above	(6.82)	0.00	(6.82)	(4.54)	0.00	(4.54)	33.4%		33.4%
Voltage Discount, Time Related Demand - $/kW									
From 2 kV to 50 kV				0.00	(0.03)	(0.03)			
From 51 kV to 219 kV				0.00	(0.08)	(0.08)			
220 kV and above				0.00	(0.08)	(0.08)			
Voltage Discount, Energy - $/kWh									
From 2 kV to 50 kV	(0.00031)	(0.00220)	(0.00251)	(0.00047)	(0.00108)	(0.00155)	-51.6%	50.9%	38.2%
From 51 kV to 219 kV	(0.01046)	(0.00530)	(0.01576)	(0.01468)	(0.00255)	(0.01723)	-40.3%	51.9%	-9.3%
220 kV and above	(0.01954)	(0.00535)	(0.02489)	(0.03059)	(0.00257)	(0.03316)	-56.6%	52.0%	-33.2%
Power Factor Adjustment - $/kVA									
Greater than 50 kV	0.47	0.00	0.47	0.54	0.00	0.54	14.9%		14.9%
50 kV or less	0.55	0.00	0.55	0.60	0.00	0.60	9.1%		9.1%

	January 2018 Rates			Proposed 2018 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-GS-3-D-CPP									
Critical Peak Pricing									
Time-of-Use Pricing Rate Energy Charge - $/kWh									
Summer Season									
On-Peak	0.02114	0.10130	0.12244	0.02779	0.07327	0.10106	31.5%	-27.7%	-17.5%
Mid-peak	0.02114	0.05852	0.07966	0.02779	0.06590	0.09369	31.5%	12.6%	17.6%
Off-Peak	0.02114	0.03706	0.05820	0.02779	0.04259	0.07038	31.5%	14.9%	20.9%
Winter Season									
Mid-peak	0.02114	0.05355	0.07469	0.02779	0.05594	0.08373	31.5%	4.5%	12.1%
Off-Peak	0.02114	0.04264	0.06378	0.02779	0.04696	0.07475	31.5%	10.1%	17.2%
Super-Off-Peak				0.02779	0.03010	0.05789			
Customer Charge - $/month	462.59	0.00	462.59	307.00	0.00	307.00	-33.6%		-33.6%
Facilities Related Demand Charge - $/kW	18.29	0.00	18.29	12.47	0.00	12.47	-31.8%		-31.8%
Time Related Demand Charge - $/kW									
Summer Season On-Peak	0.00	20.01	20.01	10.29	16.82	27.11		-15.9%	35.5%
Mid-Peak	0.00	3.94	3.94	0.00	0.00	0.00		-100.0%	-100.0%
Winter Season Mid-Peak	0.00	0.00	0.00	3.46	3.04	6.50			
Voltage Discount, Facilities Related Demand - $/kW									
From 2 kV to 50 kV	(0.22)	0.00	(0.22)	(0.13)	0.00	(0.13)	40.9%		40.9%
From 51 kV to 219 kV	(7.31)	0.00	(7.31)	(4.93)	0.00	(4.93)	32.6%		32.6%
220 kV and above	(13.66)	0.00	(13.66)	(8.15)	0.00	(8.15)	40.3%		40.3%
Voltage Discount, Time-Related Demand - $/kW									
From 2 kV to 50 kV	0.00	(0.39)	(0.39)	(0.09)	(0.14)	(0.23)		64.1%	41.0%
From 51 kV to 219 kV	0.00	(1.07)	(1.07)	(2.46)	(0.39)	(2.85)		63.6%	-166.4%
220 kV and above	0.00	(1.08)	(1.08)	(5.92)	(0.39)	(6.31)		63.9%	-484.3%
Voltage Discount, Energy - $/kWh									
From 2 kV to 50 kV	0.00000	(0.00140)	(0.00140)	(0.00008)	(0.00079)	(0.00087)		43.6%	37.9%
From 51 kV to 219 kV	0.00000	(0.00309)	(0.00309)	(0.00229)	(0.00175)	(0.00404)		43.4%	-30.7%
220 kV and above	0.00000	(0.00312)	(0.00312)	(0.00554)	(0.00177)	(0.00731)		43.3%	-134.3%
Power Factor Adjustment - $/kVA									
Greater than 50 kV	0.47	0.00	0.47	0.54	0.00	0.54	14.9%		14.9%
50 kV or less	0.55	0.00	0.55	0.60	0.00	0.60	9.1%		9.1%
CPP Event Energy Charge - $/kWh	0.00000	1.37453	1.37453	0.00000	0.40000	0.40000		-70.9%	-70.9%
Summer CPP Non-Event Credit									
On-Peak Demand Credit - $/kW	0.00	(11.44)	(11.44)	0.00	(3.77)	(3.77)		67.0%	67.0%
TOU-GS-3-RTP									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.02114	Variable*	Variable*	0.02779	Variable*	Variable*	31.5%		
Mid-peak				0.02779	Variable*	Variable*			
Off-Peak				0.02779	Variable*	Variable*			
Winter Season									
Mid-peak				0.02779	Variable*	Variable*			
Off-Peak				0.02779	Variable*	Variable*			
Super-Off-Peak				0.02779	Variable*	Variable*			
Customer Charge - $/month	462.59	0.00	462.59	307.00	0.00	307.00	-33.6%		-33.6%
Facilities Related									
Demand Charge - $/kW	18.29	0.00	18.29	12.47	0.00	12.47	-31.8%		-31.8%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak				10.29	0.00	10.29			
Mid-Peak				0.00	0.00	0.00			
Voltage Discount, Facilities Related Demand - $/kW									
From 2 kV to 50 kV	(0.22)	0.00	(0.22)	(0.13)	0.00	(0.13)	40.9%		40.9%
Above 50 kV but below 220 kV	(7.31)	0.00	(7.31)	(4.93)	0.00	(4.93)	32.6%		32.6%
At 220 kV	(13.66)	0.00	(13.66)	(8.15)	0.00	(8.15)	40.3%		40.3%
Voltage Discount, Time-Related Demand - $/kW									
From 2 kV to 50 kV				(0.09)	0.00	(0.09)			
From 51 kV to 219 kV				(2.46)	0.00	(2.46)			
220 kV and above				(5.92)	0.00	(5.92)			
Voltage Discount, Energy - $/kWh									
From 2 kV to 50 kV	0.00000	(0.00220)	(0.00220)	(0.00008)	(0.00108)	(0.00116)		50.9%	47.3%
From 51 kV to 219 kV	0.00000	(0.00530)	(0.00530)	(0.00229)	(0.00255)	(0.00484)		51.9%	8.7%
220 kV and above	0.00000	(0.00535)	(0.00535)	(0.00554)	(0.00257)	(0.00811)		52.0%	-51.6%
Power Factor Adjustment - $/kVA									
Greater than 50 kV	0.47	0.00	0.47	0.54	0.00	0.54	14.9%		14.9%
50 kV or less	0.55	0.00	0.55	0.60	0.00	0.60	9.1%		9.1%

	January 2018 Rates			Proposed 2018 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-EV-6 (Below 2kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.03911	0.41917	0.45828	0.13647	0.28444	0.42091			
Off-Peak	0.03911	0.05426	0.09337	0.08834	0.06163	0.14997			
SOff-Peak	0.03911	0.03336	0.07247	0.05616	0.03866	0.09482			
Winter Season									
On-Peak	0.03911	0.04939	0.08850	0.04491	0.08356	0.12847			
Off-Peak	0.03911	0.04538	0.08449	0.02943	0.04262	0.07205			
SOff-Peak	0.03911	0.03771	0.07682	0.03809	0.02731	0.06540			
Customer Charge - $/month	658.17	0.00	658.17	459.50		459.50			
Facilities Related Demand Charge - $/kW	11.81	0.00	11.81	9.05		9.05			
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak									
Off-Peak									
SOff-Peak									
Winter Season									
On-Peak									
Off-Peak									
SOff-Peak									
Power Factor Adjustment - $/kVA	0.55	0.00	0.55	0.60		0.60			
TOU-EV-6 (From 2 kV to 50 kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.03636	0.41434	0.45070	0.12574	0.27057	0.39631			
Off-Peak	0.03636	0.05280	0.08916	0.07437	0.05846	0.13283			
SOff-Peak	0.03636	0.03269	0.06905	0.04999	0.03701	0.08700			
Winter Season									
On-Peak	0.03636	0.04840	0.08476	0.04029	0.07921	0.11950			
Off-Peak	0.03636	0.04447	0.08083	0.02656	0.04082	0.06738			
SOff-Peak	0.03636	0.03696	0.07332	0.03500	0.02617	0.06117			
Customer Charge - $/month	314.30	0.00	314.30	244.75		244.75			
Facilities Related Demand Charge - $/kW	11.68	0.00	11.68	8.83		8.83			
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak									
Off-Peak									
SOff-Peak									
Winter Season									
On-Peak									
Off-Peak									
SOff-Peak									
Power Factor Adjustment - $/kVA	0.55	0.00	0.55	0.60		0.60			

	January 2018 Rates			Proposed 2018 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-EV-6 (Above 50 kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.02338	0.37427	0.39765	0.07075	0.26955	0.34030			
Off-Peak	0.02338	0.05133	0.07471	0.03797	0.05540	0.09337			
SOff-Peak	0.02338	0.03260	0.05598	0.02278	0.03639	0.05917			
Winter Season									
On-Peak	0.02338	0.04828	0.07166	0.02175	0.08340	0.10515			
Off-Peak	0.02338	0.04435	0.06773	0.01739	0.04034	0.05773			
SOff-Peak	0.02338	0.03686	0.06024	0.01803	0.02580	0.04383			
Customer Charge - $/month	2,110.04	0.00	2,110.04	1624.75		1624.75			
Facilities Related Demand Charge - $/kW	4.79	0.00	4.79	5.30		5.30			
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak									
Off-Peak									
SOff-Peak									
Winter Season									
On-Peak									
Off-Peak									
SOff-Peak									
Power Factor Adjustment - $/kVA	0.47	0.00	0.47	0.54		0.54			
Voltage Discount, 220 kV and above (Demand - $/kW)									
Facilities Related	0.00	0.00	0.00	(0.83)		(0.83)			
Time-Related (Summer)	0.00	0.00	0.00						
Voltage Discount, 220 kV and above (Energy - $/kWh)									
Energy	(0.00678)	(0.00064)	(0.00742)	(0.00544)	(0.00055)	(0.00599)			
TOU-8-D (Below 2kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.02012	0.08246	0.10258	0.02695	0.06853	0.09548	33.9%	-16.9%	-6.9%
Mid-peak	0.02012	0.05554	0.07566	0.02695	0.06163	0.08858	33.9%	11.0%	17.1%
Off-Peak	0.02012	0.03715	0.05727	0.02695	0.03866	0.06561	33.9%	4.1%	14.6%
Winter Season									
Mid-peak	0.02012	0.05369	0.07381	0.02695	0.05078	0.07773	33.9%	-5.4%	5.3%
Off-Peak	0.02012	0.04274	0.06286	0.02695	0.04262	0.06957	33.9%	-0.3%	10.7%
Super-Off-Peak				0.02695	0.02731	0.05426			
Customer Charge - $/month	658.17	0.00	658.17	459.50	0.00	459.50	-30.2%		-30.2%
Facilities Related									
Demand Charge - $/kW	19.02	0.00	19.02	12.70	0.00	12.70	-33.2%		-33.2%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	0.00	21.73	21.73	9.85	19.94	29.79		-8.2%	37.1%
Mid-Peak	0.00	4.17	4.17	0.00	0.00	0.00		-100.0%	-100.0%
Winter Season									
Mid-Peak	0.00	0.00	0.00	3.30	3.88	7.18			
Off-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.55	0.00	0.55	0.60	0.00	0.60	9.1%		9.1%

	January 2018 Rates			Proposed 2018 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-8-E (Below 2kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.02613	0.31805	0.34418	0.13647	0.28444	0.42091	422.3%	-10.6%	22.3%
Mid-peak	0.02613	0.08961	0.11574	0.08834	0.06163	0.14997	238.1%	-31.2%	29.6%
Off-Peak	0.02613	0.03715	0.06328	0.05616	0.03866	0.09482	114.9%	4.1%	49.8%
Winter Season									
Mid-peak	0.02613	0.05369	0.07982	0.04491	0.08356	0.12847	71.9%	55.6%	60.9%
Off-Peak	0.02613	0.04274	0.06887	0.02943	0.04262	0.07205	12.6%	-0.3%	4.6%
Super-Off-Peak				0.03809	0.02731	0.06540			
Customer Charge - $/month	658.17	0.00	658.17	459.50	0.00	459.50	-30.2%		-30.2%
Facilities Related									
Demand Charge - $/kW	16.64	0.00	16.64	9.05	0.00	9.05	-45.6%		-45.6%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak				0.00	4.01	4.01			
Mid-Peak				0.00	0.00	0.00			
Winter Season									
Mid-Peak				0.00	0.82	0.82			
Off-Peak				0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.55	0.00	0.55	0.60	0.00	0.60	9.1%		9.1%
TOU-8-D (From 2 kV to 50 kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.01899	0.08123	0.10022	0.02463	0.06502	0.08965	29.7%	-20.0%	-10.5%
Mid-peak	0.01899	0.05433	0.07332	0.02463	0.05846	0.08309	29.7%	7.6%	13.3%
Off-Peak	0.01899	0.03635	0.05534	0.02463	0.03701	0.06164	29.7%	1.8%	11.4%
Winter Season									
Mid-peak	0.01899	0.05260	0.07159	0.02463	0.04865	0.07328	29.7%	-7.5%	2.4%
Off-Peak	0.01899	0.04187	0.06086	0.02463	0.04082	0.06545	29.7%	-2.5%	7.5%
Super-Off-Peak				0.02463	0.02617	0.05080			
Customer Charge - $/month	314.30	0.00	314.30	244.75	0.00	244.75	-22.1%		-22.1%
Facilities Related									
Demand Charge - $/kW	18.79	0.00	18.79	12.48	0.00	12.48	-33.6%		-33.6%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	0.00	21.79	21.79	9.36	19.37	28.73		-11.1%	31.8%
Mid-Peak	0.00	4.11	4.11	0.00	0.00	0.00		-100.0%	-100.0%
Winter Season									
Mid-Peak	0.00	0.00	0.00	3.06	4.08	7.14			
Off-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.55	0.00	0.55	0.60	0.00	0.60	9.1%		9.1%
TOU-8-E (From 2 kV to 50 kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.02793	0.31544	0.34337	0.12574	0.27057	0.39631	350.2%	-14.2%	15.4%
Mid-peak	0.02793	0.08662	0.11455	0.07437	0.05846	0.13283	166.3%	-32.5%	16.0%
Off-Peak	0.02793	0.03635	0.06428	0.04999	0.03701	0.08700	79.0%	1.8%	35.3%
Winter Season									
Mid-peak	0.02793	0.05260	0.08053	0.04029	0.07921	0.11950	44.3%	50.6%	48.4%
Off-Peak	0.02793	0.04187	0.06980	0.02656	0.04082	0.06738	-4.9%	-2.5%	-3.5%
Super-Off-Peak				0.03500	0.02617	0.06117			
Customer Charge - $/month	314.30	0.00	314.30	244.75	0.00	244.75	-22.1%		-22.1%
Facilities Related									
Demand Charge - $/kW	14.92	0.00	14.92	8.83	0.00	8.83	-40.8%		-40.8%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak				0.00	3.44	3.44			
Mid-Peak				0.00	0.00	0.00			
Winter Season									
Mid-Peak				0.00	0.91	0.91			
Off-Peak				0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.55	0.00	0.55	0.60	0.00	0.60	9.1%		9.1%

	January 2018 Rates			Proposed 2018 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-8-D (Above 50 kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.01660	0.07748	0.09408	0.01731	0.06146	0.07877	4.3%	-20.7%	-16.3%
Mid-peak	0.01660	0.05271	0.06931	0.01731	0.05540	0.07271	4.3%	5.1%	4.9%
Off-Peak	0.01660	0.03562	0.05222	0.01731	0.03639	0.05370	4.3%	2.2%	2.8%
Winter Season									
Mid-peak	0.01660	0.05148	0.06808	0.01731	0.04787	0.06518	4.3%	-7.0%	-4.3%
Off-Peak	0.01660	0.04116	0.05776	0.01731	0.04034	0.05765	4.3%	-2.0%	-0.2%
Super-Off-Peak				0.01731	0.02580	0.04311			
Customer Charge - $/month	2,110.04	0.00	2,110.04	1,624.75	0.00	1,624.75	-23.0%		-23.0%
Facilities Related									
Demand Charge - $/kW	8.18	0.00	8.18	6.39	0.00	6.39	-21.9%		-21.9%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	0.00	21.48	21.48	4.60	18.97	23.57		-11.7%	9.7%
Mid-Peak	0.00	3.96	3.96	0.00	0.00	0.00		-100.0%	-100.0%
Winter Season									
Mid-Peak	0.00	0.00	0.00	0.52	4.69	5.21			
Off-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.47	0.00	0.47	0.54	0.00	0.54	14.9%		14.9%
Voltage Discount, 220 kV and above									
Facilities Related Demand - $/kW	(3.39)	0.00	(3.39)	(1.92)	0.00	(1.92)	43.4%		43.4%
Time-Related Demand - $/kW									
	0.00	(0.13)	(0.13)	(1.92)	(0.10)	(2.02)		23.1%	-1453.8%
Energy - $/kWh	0.00000	(0.00047)	(0.00047)	0.00000	(0.00039)	(0.00039)		17.0%	17.0%
TOU-8-E (Above 50 kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.01994	0.30144	0.32138	0.07075	0.26955	0.34030	254.8%	-10.6%	5.9%
Mid-peak	0.01994	0.08113	0.10107	0.03797	0.05540	0.09337	90.4%	-31.7%	-7.6%
Off-Peak	0.01994	0.03562	0.05556	0.02278	0.03639	0.05917	14.2%	2.2%	6.5%
Winter Season									
Mid-peak	0.01994	0.05148	0.07142	0.02175	0.08340	0.10515	9.1%	62.0%	47.2%
Off-Peak	0.01994	0.04116	0.06110	0.01739	0.04034	0.05773	-12.8%	-2.0%	-5.5%
Super-Off-Peak				0.01803	0.02580	0.04383			
Customer Charge - $/month	2,110.04	0.00	2,110.04	1624.75	0.00	1624.75	-23.0%		-23.0%
Facilities Related									
Demand Charge - $/kW	6.55	0.00	6.55	5.30	0.00	5.30	-19.1%		-19.1%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak				0.00	1.37	1.37			
Mid-Peak				0.00	0.00	0.00			
Winter Season									
Mid-Peak				0.00	0.32	0.32			
Off-Peak				0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.47	0.00	0.47	0.54	0.00	0.54	14.9%		14.9%
Voltage Discount, 220 kV and above									
Facilities Related Demand - $/kW	(1.76)	0.00	(1.76)	(0.83)	0.00	(0.83)	52.8%		52.8%
Time-Related Demand - $/kW									
	0.00	0.00	0.00	0.00	(0.01)	(0.01)			
Energy - $/kWh	0.00000	(0.00064)	(0.00064)	(0.00544)	(0.00055)	(0.00599)		14.1%	-835.9%

	January 2018 Rates			Proposed 2018 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-8-RBU (Below 2kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.02012	0.08246	0.10258	0.02218	0.06853	0.09071	10.2%	-16.9%	-11.6%
Mid-peak	0.02012	0.05554	0.07566	0.02218	0.06163	0.08381	10.2%	11.0%	10.8%
Off-Peak	0.02012	0.03715	0.05727	0.02218	0.03866	0.06084	10.2%	4.1%	6.2%
Winter Season									
Mid-peak	0.02012	0.05369	0.07381	0.02218	0.05078	0.07296	10.2%	-5.4%	-1.2%
Off-Peak	0.02012	0.04274	0.06286	0.02218	0.04262	0.06480	10.2%	-0.3%	3.1%
Super-Off-Peak				0.02218	0.02731	0.04949			
Customer Charge - $/month	174.61	0.00	174.61	139.79	0.00	139.79	-19.9%		-19.9%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	0.00	21.73	21.73	0.00	19.94	19.94		-8.2%	-8.2%
Mid-Peak	0.00	4.17	4.17	0.00	0.00	0.00		-100.0%	-100.0%
Winter Season									
Mid-Peak	0.00	0.00	0.00	0.00	3.88	3.88			
Off-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.55	0.00	0.55	0.60	0.00	0.60	9.1%		9.1%
TOU-8-RBU (From 2 kV to 50 kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.01899	0.08123	0.10022	0.02049	0.06502	0.08551	7.9%	-20.0%	-14.7%
Mid-peak	0.01899	0.05433	0.07332	0.02049	0.05846	0.07895	7.9%	7.6%	7.7%
Off-Peak	0.01899	0.03635	0.05534	0.02049	0.03701	0.05750	7.9%	1.8%	3.9%
Winter Season									
Mid-peak	0.01899	0.05260	0.07159	0.02049	0.04865	0.06914	7.9%	-7.5%	-3.4%
Off-Peak	0.01899	0.04187	0.06086	0.02049	0.04082	0.06131	7.9%	-2.5%	0.7%
Super-Off-Peak				0.02049	0.02617	0.04666			
Customer Charge - $/month	314.30	0.00	314.30	244.75	0.00	244.75	-22.1%		-22.1%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	0.00	21.79	21.79	0.00	19.37	19.37		-11.1%	-11.1%
Mid-Peak	0.00	4.11	4.11	0.00	0.00	0.00		-100.0%	-100.0%
Winter Season									
Mid-Peak	0.00	0.00	0.00	0.00	4.08	4.08			
Off-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.55	0.00	0.55	0.60	0.00	0.60	9.1%		9.1%

	January 2018 Rates			Proposed 2018 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-8-RBU (Above 50 kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.01660	0.07748	0.09408	0.01731	0.06146	0.07877	4.3%	-20.7%	-16.3%
Mid-peak	0.01660	0.05271	0.06931	0.01731	0.05540	0.07271	4.3%	5.1%	4.9%
Off-Peak	0.01660	0.03562	0.05222	0.01731	0.03639	0.05370	4.3%	2.2%	2.8%
Winter Season									
Mid-peak	0.01660	0.05148	0.06808	0.01731	0.04787	0.06518	4.3%	-7.0%	-4.3%
Off-Peak	0.01660	0.04116	0.05776	0.01731	0.04034	0.05765	4.3%	-2.0%	-0.2%
Super-Off-Peak				0.01731	0.02580	0.04311			
Customer Charge - $/month	2,110.04	0.00	2,110.04	1,624.75	0.00	1,624.75	-23.0%		-23.0%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	0.00	21.48	21.48	0.00	18.97	18.97		-11.7%	-11.7%
Mid-Peak	0.00	3.96	3.96	0.00	0.00	0.00		-100.0%	-100.0%
Winter Season									
Mid-Peak	0.00	0.00	0.00	0.00	4.69	4.69			
Off-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.47	0.00	0.47	0.54	0.00	0.54	14.9%		14.9%
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									
	0.00	(0.13)	(0.13)	0.00	(0.10)	(0.10)		23.1%	23.1%
Energy - $/kWh	0.00000	(0.00047)	(0.00047)	0.00000	(0.00039)	(0.00039)		17.0%	17.0%
TOU-8-D-CPP (Below 2kV)									
Critical Peak Pricing									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.02012	0.08246	0.10258	0.02695	0.06853	0.09548	33.9%	-16.9%	-6.9%
Mid-peak	0.02012	0.05554	0.07566	0.02695	0.06163	0.08858	33.9%	11.0%	17.1%
Off-Peak	0.02012	0.03715	0.05727	0.02695	0.03866	0.06561	33.9%	4.1%	14.6%
Winter Season									
Mid-peak	0.02012	0.05369	0.07381	0.02695	0.05078	0.07773	33.9%	-5.4%	5.3%
Off-Peak	0.02012	0.04274	0.06286	0.02695	0.04262	0.06957	33.9%	-0.3%	10.7%
Super-Off-Peak				0.02695	0.02731	0.05426			
Customer Charge - $/month	658.17	0.00	658.17	459.50	0.00	459.50	-30.2%		-30.2%
Facilities Related									
Demand Charge - $/kW	19.02	0.00	19.02	12.70	0.00	12.70	-33.2%		-33.2%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	0.00	21.73	21.73	9.85	19.94	29.79		-8.2%	37.1%
Mid-Peak	0.00	4.17	4.17	0.00	0.00	0.00		-100.0%	-100.0%
Off-Peak	0.00	0.00	0.00						
Winter Season									
Mid-Peak	0.00	0.00	0.00	3.30	3.88	7.18			
Off-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.55	0.00	0.55	0.60	0.00	0.60	9.1%		9.1%
CPP Event Energy Charge - $/kWh	0.00000	1.37453	1.37453	0.00000	0.40000	0.40000		-70.9%	-70.9%
Summer CPP Non-Event Credit									
On-Peak Demand Credit - $/kW	0.00	(11.93)	(11.93)	0.00	(4.11)	(4.11)		65.5%	65.5%

	January 2018 Rates			Proposed 2018 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-8-D-CPP (From 2 kV to 50 kV)									
Critical Peak Pricing									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.01899	0.08123	0.10022	0.02463	0.06502	0.08965	29.7%	-20.0%	-10.5%
Mid-peak	0.01899	0.05433	0.07332	0.02463	0.05846	0.08309	29.7%	7.6%	13.3%
Off-Peak	0.01899	0.03635	0.05534	0.02463	0.03701	0.06164	29.7%	1.8%	11.4%
Winter Season									
Mid-peak	0.01899	0.05260	0.07159	0.02463	0.04865	0.07328	29.7%	-7.5%	2.4%
Off-Peak	0.01899	0.04187	0.06086	0.02463	0.04082	0.06545	29.7%	-2.5%	7.5%
Super-Off-Peak				0.02463	0.02617	0.05080			
Customer Charge - $/month	314.30	0.00	314.30	244.75	0.00	244.75	-22.1%		-22.1%
Facilities Related									
Demand Charge - $/kW	18.79	0.00	18.79	12.48	0.00	12.48	-33.6%		-33.6%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	0.00	21.79	21.79	9.36	19.37	28.73		-11.1%	31.8%
Mid-Peak	0.00	4.11	4.11	0.00	0.00	0.00		-100.0%	-100.0%
Off-Peak	0.00	0.00	0.00						
Winter Season									
Mid-Peak	0.00	0.00	0.00	3.06	4.08	7.14			
Off-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.55	0.00	0.55	0.60	0.00	0.60	9.1%		9.1%
CPP Event Energy Charge - $/kWh	0.00000	1.34519	1.34519	0.00000	0.40000	0.40000		-70.3%	-70.3%
Summer CPP Non-Event Credit									
On-Peak Demand Credit - $/kW	0.00	(11.82)	(11.82)	0.00	(4.26)	(4.26)		64.0%	64.0%
TOU-8-D-CPP (Above 50 kV)									
Critical Peak Pricing									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.01660	0.07748	0.09408	0.01731	0.06146	0.07877	4.3%	-20.7%	-16.3%
Mid-peak	0.01660	0.05271	0.06931	0.01731	0.05540	0.07271	4.3%	5.1%	4.9%
Off-Peak	0.01660	0.03562	0.05222	0.01731	0.03639	0.05370	4.3%	2.2%	2.8%
Winter Season									
Mid-peak	0.01660	0.05148	0.06808	0.01731	0.04787	0.06518	4.3%	-7.0%	-4.3%
Off-Peak	0.01660	0.04116	0.05776	0.01731	0.04034	0.05765	4.3%	-2.0%	-0.2%
Super-Off-Peak				0.01731	0.02580	0.04311			
Customer Charge - $/month	2,110.04	0.00	2,110.04	1,624.75	0.00	1,624.75	-23.0%		-23.0%
Facilities Related									
Demand Charge - $/kW	8.18	0.00	8.18	6.39	0.00	6.39	-21.9%		-21.9%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	0.00	21.48	21.48	4.60	18.97	23.57		-11.7%	9.7%
Mid-Peak	0.00	3.96	3.96	0.00	0.00	0.00		-100.0%	-100.0%
Off-Peak	0.00	0.00	0.00						
Winter Season									
Mid-Peak	0.00	0.00	0.00	0.52	4.69	5.21			
Off-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.47	0.00	0.47	0.54	0.00	0.54	14.9%		14.9%
CPP Event Energy Charge - $/kWh	0.00000	1.29359	1.29359	0.00000	0.40000	0.40000		-69.1%	-69.1%
Summer CPP Non-Event Credit									
On-Peak Demand Credit - $/kW	0.00	(11.58)	(11.58)	0.00	(4.22)	(4.22)		63.6%	63.6%
Voltage Discount, 220 kV and above									
Facilities Related Demand - $/kW	(3.39)	0.00	(3.39)	(1.92)	0.00	(1.92)	43.4%		43.4%
Time-Related Demand - $/kW									
	0.00	(0.13)	(0.13)	(1.92)	(0.10)	(2.02)		23.1%	-1453.8%
Energy - $/kWh	0.00000	(0.00047)	(0.00047)	0.00000	(0.00039)	(0.00039)		17.0%	17.0%

	January 2018 Rates			Proposed 2018 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-8-RTP (Below 2kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.02012	Variable*	Variable*	0.02695	Variable*	Variable*	33.9%		
Mid-peak				0.02695	Variable*	Variable*			
Off-Peak				0.02695	Variable*	Variable*			
Winter Season									
Mid-peak				0.02695	Variable*	Variable*			
Off-Peak				0.02695	Variable*	Variable*			
Super-Off-Peak				0.02695	Variable*	Variable*			
Customer Charge - $/month	658.17	0.00	658.17	459.50	0.00	459.50	-30.2%		-30.2%
Facilities Related									
Demand Charge - $/kW	19.02	0.00	19.02	12.70	0.00	12.70	-33.2%		-33.2%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak				9.85	0.00	9.85			
Mid-Peak				0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.55	0.00	0.55	0.60	0.00	0.60	9.1%		9.1%
TOU-8-RTP (From 2 kV to 50 kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.01899	Variable*	Variable*	0.02463	Variable*	Variable*	29.7%		
Mid-peak				0.02463	Variable*	Variable*			
Off-Peak				0.02463	Variable*	Variable*			
Winter Season									
Mid-peak				0.02463	Variable*	Variable*			
Off-Peak				0.02463	Variable*	Variable*			
Super-Off-Peak				0.02463	Variable*	Variable*			
Customer Charge - $/month	314.30	0.00	314.30	244.75	0.00	244.75	-22.1%		-22.1%
Facilities Related									
Demand Charge - $/kW	18.79	0.00	18.79	12.48	0.00	12.48	-33.6%		-33.6%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak				9.36	0.00	9.36			
Mid-Peak				0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.55	0.00	0.55	0.60	0.00	0.60	9.1%		9.1%
TOU-8-RTP (Above 50 kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.01660	Variable*	Variable*	0.01731	Variable*	Variable*	4.3%		
Mid-peak				0.01731	Variable*	Variable*			
Off-Peak				0.01731	Variable*	Variable*			
Winter Season									
Mid-peak				0.01731	Variable*	Variable*			
Off-Peak				0.01731	Variable*	Variable*			
Super-Off-Peak				0.01731	Variable*	Variable*			
Customer Charge - $/month	2,110.04	0.00	2,110.04	1,624.75	0.00	1,624.75	-23.0%		-23.0%
Facilities Related									
Demand Charge - $/kW	8.18	0.00	8.18	6.39	0.00	6.39	-21.9%		-21.9%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak				4.60	0.00	4.60			
Mid-Peak				0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.47	0.00	0.47	0.54	0.00	0.54	14.9%		14.9%
Voltage Discount, 220 kV and above									
Facilities Related Demand - $/kW	(3.39)	0.00	(3.39)	(1.92)	0.00	(1.92)	43.4%		43.4%
Time-Related Demand - $/kW				(1.92)	0.00	(1.92)			
Energy - $/kWh	0.00000	(0.00064)	(0.00064)	0.00000	(0.00055)	(0.00055)		14.1%	14.1%

	January 2018 Rates			Proposed 2018 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-BIP Rate - $/kW (Applicable: Average kW demand)									
A (15-min notfication)									
BIP Rate Credit ($/KW)									
Below 2 kV - Summer Average On Peak	(22.54)	0.00	(22.54)	(21.76)		(21.76)	3.5%		3.5%
Summer Average Mid - Peak	(7.07)	0.00	(7.07)	(1.70)		(1.70)	76.0%		76.0%
Summer Average Off - Peak				0.00		0.00			
Winter Average Mid - Peak	(1.46)	0.00	(1.46)	(9.14)		(9.14)	-526.0%		-526.0%
Excess Energy Charge - $/kWh	14.80456	0.00000	14.80456	12.48488		12.48488	-15.7%		-15.7%
From 2 kV to 50 kV - Summer Average On Peak	(21.82)	0.00	(21.82)	(21.76)		(21.76)	0.3%		0.3%
Summer Average Mid - Peak	(6.57)	0.00	(6.57)	(1.42)		(1.42)	78.4%		78.4%
Summer Average Off - Peak				0.00		0.00			
Winter Average Mid - Peak	(1.36)	0.00	(1.36)	(8.55)		(8.55)	-528.7%		-528.7%
Excess Energy Charge - $/kWh	14.49402	0.00000	14.49402	12.24444		12.24444	-15.5%		-15.5%
above 50 kV - Summer Average On Peak	(19.35)	0.00	(19.35)	(14.87)		(14.87)	23.2%		23.2%
Summer Average Mid - Peak	(5.57)	0.00	(5.57)	(0.72)		(0.72)	87.1%		87.1%
Summer Average Off - Peak				0.00		0.00			
Winter Average Mid - Peak	(1.17)	0.00	(1.17)	(5.38)		(5.38)	-359.8%		-359.8%
Excess Energy Charge - $/kWh	13.94961	0.00000	13.94961	11.82401		11.82401	-15.2%		-15.2%
B (30-min notification)									
BIP Rate Credit ($/KW)									
Below 2 kV - Summer Average On Peak	(21.23)	0.00	(21.23)	(19.62)		(19.62)	7.6%		7.6%
Summer Average Mid - Peak	(6.66)	0.00	(6.66)	(1.53)		(1.53)	77.0%		77.0%
Summer Average Off - Peak				0.00		0.00			
Winter Average Mid - Peak	(1.38)	0.00	(1.38)	(8.24)		(8.24)	-497.1%		-497.1%
Excess Energy Charge - $/kWh	13.89417	0.00000	13.89417	11.26027		11.26027	-19.0%		-19.0%
From 2 kV to 50 kV - Summer Average On Peak	(20.51)	0.00	(20.51)	(19.28)		(19.28)	6.0%		6.0%
Summer Average Mid - Peak	(6.18)	0.00	(6.18)	(1.25)		(1.25)	79.8%		79.8%
Summer Average Off - Peak				0.00		0.00			
Winter Average Mid - Peak	(1.28)	0.00	(1.28)	(7.56)		(7.56)	-490.6%		-490.6%
Excess Energy Charge - $/kWh	13.60306	0.00000	13.60306	11.01982		11.01982	-19.0%		-19.0%
above 50 kV - Summer Average On Peak	(18.14)	0.00	(18.14)	(12.81)		(12.81)	29.4%		29.4%
Summer Average Mid - Peak	(5.21)	0.00	(5.21)	(0.61)		(0.61)	88.3%		88.3%
Summer Average Off - Peak				0.00		0.00			
Winter Average Mid - Peak	(1.09)	0.00	(1.09)	(4.62)		(4.62)	-323.9%		-323.9%
Excess Energy Charge - $/kWh	13.09274	0.00000	13.09274	10.59939		10.59939	-19.0%		-19.0%
TOU-8-S-D (Below 2kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.01994	0.08253	0.10247	0.02777	0.06853	0.09630	39.3%	-17.0%	-6.0%
Mid-peak	0.01994	0.05558	0.07552	0.02777	0.06163	0.08940	39.3%	10.9%	18.4%
Off-Peak	0.01994	0.03718	0.05712	0.02777	0.03866	0.06643	39.3%	4.0%	16.3%
Winter Season									
Mid-peak	0.01994	0.05373	0.07367	0.02777	0.05078	0.07855	39.3%	-5.5%	6.6%
Off-Peak	0.01994	0.04278	0.06272	0.02777	0.04262	0.07039	39.3%	-0.4%	12.2%
Super-Off-Peak				0.02777	0.02731	0.05508			
Customer Charge - $/month	658.18	0.00	658.18	459.50	0.00	459.50	-30.2%		-30.2%
Facilities Related Demand									
Demand Charge (Excess FRD) - $/kW	19.02	0.00	19.02	12.70	0.00	12.70	-33.2%		-33.2%
Standby (CRC) - $/kW	9.80	0.00	9.80	10.45	0.00	10.45	6.6%		6.6%
Time Related Demand Charge - $/kW									
Backup demand - Summer Season									
On-Peak	0.00	17.00	17.00	7.09	16.02	23.11		-5.8%	35.9%
Mid-Peak	0.00	2.88	2.88	0.00	0.00	0.00		-100.0%	-100.0%
Winter Season									
Mid-Peak				2.19	3.26	5.45			
Supplemental demand - Summer Season									
On-Peak	0.00	21.74	21.74	9.85	19.94	29.79		-8.3%	37.0%
Mid-Peak	0.00	4.17	4.17	0.00	0.00	0.00		-100.0%	-100.0%
Winter Season									
Mid-Peak				3.30	3.88	7.18			
Power Factor Adjustment - $/kVA	0.55	0.00	0.55	0.60	0.00	0.60	9.1%		9.1%

	January 2018 Rates			Proposed 2018 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-8-S-LG (Below 2kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.01994	0.31805	0.33799	0.04960	0.33871	0.38831	148.7%	6.5%	14.9%
Mid-peak	0.01994	0.08961	0.10955	0.04960	0.06163	0.11123	148.7%	-31.2%	1.5%
Off-Peak	0.01994	0.03715	0.05709	0.04960	0.03866	0.08826	148.7%	4.1%	54.6%
Winter Season									
Mid-peak	0.01994	0.05369	0.07363	0.04960	0.09228	0.14188	148.7%	71.9%	92.7%
Off-Peak	0.01994	0.04274	0.06268	0.04960	0.04262	0.09222	148.7%	-0.3%	47.1%
Super-Off-Peak				0.04960	0.02731	0.07691			
Customer Charge - $/month	658.18	0.00	658.18	459.50	0.00	459.50	-30.2%		-30.2%
Facilities Related Demand									
Demand Charge (Excess FRD) - $/kW	19.02	0.00	19.02	9.05	0.00	9.05	-52.4%		-52.4%
Standby (CRC) - $/kW	9.80	0.00	9.80	10.45	0.00	10.45	6.6%		6.6%
Time Related Demand Charge - $/kW									
Backup demand - Summer Season									
On-Peak	0.00	17.00	17.00	7.09	16.02	23.11		-5.8%	35.9%
Mid-Peak	0.00	2.88	2.88	0.00	0.00	0.00		-100.0%	-100.0%
Winter Season								-100.0%	-100.0%
Mid-Peak				0.00	3.26	3.26			
Supplemental demand - Summer Season									
On-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season									
Mid-Peak				0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.55	0.00	0.55	0.60	0.00	0.60	9.1%		9.1%
TOU-8-S-D (From 2 kV to 50 kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.01918	0.08098	0.10016	0.02817	0.06502	0.09319	46.9%	-19.7%	-7.0%
Mid-peak	0.01918	0.05416	0.07334	0.02817	0.05846	0.08663	46.9%	7.9%	18.1%
Off-Peak	0.01918	0.03625	0.05543	0.02817	0.03701	0.06518	46.9%	2.1%	17.6%
Winter Season									
Mid-peak	0.01918	0.05244	0.07162	0.02817	0.04865	0.07682	46.9%	-7.2%	7.3%
Off-Peak	0.01918	0.04173	0.06091	0.02817	0.04082	0.06899	46.9%	-2.2%	13.3%
Super-Off-Peak				0.02817	0.02617	0.05434			
Customer Charge - $/month	314.58	0.00	314.58	244.75	0.00	244.75	-22.2%		-22.2%
Facilities Related Demand									
Demand Charge (Excess FRD) - $/kW	18.80	0.00	18.80	12.48	0.00	12.48	-33.6%		-33.6%
Standby (CRC) - $/kW	8.67	0.00	8.67	6.89	0.00	6.89	-20.5%		-20.5%
Time Related Demand Charge - $/kW									
Backup demand - Summer Season									
On-Peak	0.00	14.15	14.15	5.29	13.77	19.06		-2.7%	34.7%
Mid-Peak	0.00	2.61	2.61	0.00	0.00	0.00		-100.0%	-100.0%
Winter Season									
Mid-Peak				1.73	3.62	5.35			
Supplemental demand - Summer Season									
On-Peak	0.00	21.72	21.72	9.36	19.37	28.73		-10.8%	32.3%
Mid-Peak	0.00	4.10	4.10	0.00	0.00	0.00		-100.0%	-100.0%
Winter Season									
Mid-Peak				3.06	4.08	7.14			
Power Factor Adjustment - $/kVA	0.55	0.00	0.55	0.60	0.00	0.60	9.1%		9.1%

	January 2018 Rates			Proposed 2018 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-8-S-LG (From 2 kV to 50 kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.01918	0.31544	0.33462	0.04708	0.31500	0.36208	145.5%	-0.1%	8.2%
Mid-peak	0.01918	0.08662	0.10580	0.04708	0.05846	0.10554	145.5%	-32.5%	-0.2%
Off-Peak	0.01918	0.03635	0.05553	0.04708	0.03701	0.08409	145.5%	1.8%	51.4%
Winter Season									
Mid-peak	0.01918	0.05260	0.07178	0.04708	0.08793	0.13501	145.5%	67.2%	88.1%
Off-Peak	0.01918	0.04187	0.06105	0.04708	0.04082	0.08790	145.5%	-2.5%	44.0%
Super-Off-Peak				0.04708	0.02617	0.07325			
Customer Charge - $/month	314.58	0.00	314.58	244.75	0.00	244.75	-22.2%		-22.2%
Facilities Related Demand									
Demand Charge (Excess FRD) - $/kW	18.80	0.00	18.80	8.83	0.00	8.83	-53.0%		-53.0%
Standby (CRC) - $/kW	8.67	0.00	8.67	6.89	0.00	6.89	-20.5%		-20.5%
Time Related Demand Charge - $/kW									
Backup demand - Summer Season									
On-Peak	0.00	14.15	14.15	5.29	13.77	19.06		-2.7%	34.7%
Mid-Peak	0.00	2.61	2.61	0.00	0.00	0.00		-100.0%	-100.0%
Winter Season									
Mid-Peak				0.00	3.62	3.62			
Supplemental demand - Summer Season									
On-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season									
Mid-Peak				0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.55	0.00	0.55	0.60	0.00	0.60	9.1%		9.1%
TOU-8-S-D (Above 50 kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.01623	0.07729	0.09352	0.01680	0.06146	0.07826	3.5%	-20.5%	-16.3%
Mid-peak	0.01623	0.05257	0.06880	0.01680	0.05540	0.07220	3.5%	5.4%	4.9%
Off-Peak	0.01623	0.03553	0.05176	0.01680	0.03639	0.05319	3.5%	2.4%	2.8%
Winter Season									
Mid-peak	0.01623	0.05136	0.06759	0.01680	0.04787	0.06467	3.5%	-6.8%	-4.3%
Off-Peak	0.01623	0.04105	0.05728	0.01680	0.04034	0.05714	3.5%	-1.7%	-0.2%
Super-Off-Peak				0.01680	0.02580	0.04260			
Customer Charge - $/month	2,112.27	0.00	2,112.27	1,624.75	0.00	1,624.75	-23.1%		-23.1%
Facilities Related Demand									
Demand Charge (Excess FRD) - $/kW	8.19	0.00	8.19	6.39	0.00	6.39	-22.0%		-22.0%
Standby (CRC) - $/kW	0.98	0.00	0.98	0.77	0.00	0.77	-21.4%		-21.4%
Time Related Demand Charge - $/kW									
Backup demand - Summer Season									
On-Peak	0.00	10.20	10.20	1.10	5.47	6.57		-46.4%	-35.6%
Mid-Peak	0.00	1.48	1.48	0.00	0.00	0.00		-100.0%	-100.0%
Winter Season									
Mid-Peak				0.11	1.28	1.39			
Supplemental demand - Summer Season									
On-Peak	0.00	21.42	21.42	4.60	18.97	23.57		-11.4%	10.0%
Mid-Peak	0.00	3.95	3.95	0.00	0.00	0.00		-100.0%	-100.0%
Winter Season									
Mid-Peak				0.52	4.69	5.21			
Power Factor Adjustment - $/kVA	0.47	0.00	0.47	0.54	0.00	0.54	14.9%		14.9%
Voltage Discount, 220 kV and above									
Facilities Related Demand (Excess FRD) - $k/W	(3.40)	0.00	(3.40)	(1.92)	0.00	(1.92)	43.5%		43.5%
Time-Related Demand - $/kW									
Supplemental Summer on & Winter Mid	0.00	(0.13)	(0.13)	(1.92)	(0.10)	(2.02)		23.1%	-1453.8%
Backup Summer on & Winter Mid				(0.41)	(0.03)	(0.44)			
Energy - $/kWh	0.00000	(0.00047)	(0.00047)	0.00000	(0.00039)	(0.00039)		17.0%	17.0%
Standby (CRC) - $/kW	(0.44)	0.00	(0.44)	(0.27)	0.00	(0.27)	38.6%		38.6%

	January 2018 Rates			Proposed 2018 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-8-S-LG (Above 50 kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.01623	0.30144	0.31767	0.03502	0.28572	0.32074	115.8%	-5.2%	1.0%
Mid-peak	0.01623	0.08113	0.09736	0.03502	0.05540	0.09042	115.8%	-31.7%	-7.1%
Off-Peak	0.01623	0.03562	0.05185	0.01944	0.03639	0.05583	19.8%	2.2%	7.7%
Winter Season									
Mid-peak	0.01623	0.05148	0.06771	0.03502	0.08600	0.12102	115.8%	67.1%	78.7%
Off-Peak	0.01623	0.04116	0.05739	0.01944	0.04034	0.05978	19.8%	-2.0%	4.2%
Super-Off-Peak				0.01752	0.02580	0.04332			
Customer Charge - $/month	2,112.27	0.00	2,112.27	1,624.75	0.00	1,624.75	-23.1%		-23.1%
Facilities Related Demand									
Demand Charge (Excess FRD) - $/kW	8.19	0.00	8.19	5.30	0.00	5.30	-35.3%		-35.3%
Standby (CRC) - $/kW	0.98	0.00	0.98	0.77	0.00	0.77	-21.4%		-21.4%
Time Related Demand Charge - $/kW									
Backup demand - Summer Season									
On-Peak	0.00	10.20	10.20	1.10	5.47	6.57		-46.4%	-35.6%
Mid-Peak	0.00	1.48	1.48	0.00	0.00	0.00		-100.0%	-100.0%
Winter Season									
Mid-Peak				0.11	1.28	1.39			
Supplemental demand - Summer Season									
On-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season									
Mid-Peak				0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.47	0.00	0.47	0.54	0.00	0.54	0.14894		0.14894
Voltage Discount, 220 kV and above									
Facilities Related Demand (Excess FRD) - $k/W	(3.40)	0.00	(3.40)	(0.83)	0.00	(0.83)	75.6%		75.6%
Time-Related Demand - $/kW									
Supplemental Summer on & Winter Mid	0.00	0.00	0.00	0.00	0.00	0.00			
Backup Summer on & Winter Mid				(1.10)	(0.03)	(1.13)			
Energy - $/kWh	0.00000	(0.00064)	(0.00064)	(0.00544)	(0.00056)	(0.00600)		12.5%	-837.5%
Standby (CRC) - $/kW	(0.44)	0.00	(0.44)	(0.27)	0.00	(0.27)	38.6%		38.6%

	January 2018 Rates			Proposed 2018 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
Schedule-S-D (Less than 500 kW)									
Energy Charge - $/kWh/Meter/Month - see (OAT)									
Customer Charge - $/Meter/Month - see (OAT)									
Standby (CRC) - $kW									
TOU-GS-2 (Rate D)	9.80	0.00	9.80	10.45	0.00	10.45	6.6%		6.6%
Voltage Discount, Capacity Reservation Demand - $/kW									
From 2 kV to 50 kV	(0.11)	0.00	(0.11)	(0.11)	0.00	(0.11)	0.0%		0.0%
51 kV to 219 kV	(3.77)	0.00	(3.77)	(4.10)	0.00	(4.10)	-8.8%		-8.8%
220 kV and Above	(6.32)	0.00	(6.32)	(7.21)	0.00	(7.21)	-14.1%		-14.1%
TOU-GS-2 (Rate E)				7.51	0.00	7.51			
Voltage Discount, Capacity Reservation Demand - $/kW									
From 2 kV to 50 kV				(0.06)	0.00	(0.06)			
51 kV to 219 kV				(2.43)	0.00	(2.43)			
220 kV and Above				(4.27)	0.00	(4.27)			
TOU-GS-3 (Rate D)	9.80	0.00	9.80	10.45	0.00	10.45	6.6%		6.6%
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%		-20.0%
51 kV to 219 kV	(3.38)	0.00	(3.38)	(4.36)	0.00	(4.36)	-29.0%		-29.0%
220 kV and Above	(6.32)	0.00	(6.32)	(7.21)	0.00	(7.21)	-14.1%		-14.1%
TOU-GS-3 (Rate E)				7.78	0.00	7.78			
Voltage Discount, Capacity Reservation Demand - $/kW									
From 2 kV to 50 kV				(0.07)	0.00	(0.07)			
51 kV to 219 kV				(2.75)	0.00	(2.75)			
220 kV and Above				(4.54)	0.00	(4.54)			
GS-2	9.80	0.00	9.80	10.45	0.00	10.45	6.6%		6.6%
Voltage Discount, Capacity Reservation Demand - $/kW									
From 2 kV to 50 kV	(0.11)	0.00	(0.11)	(0.11)	0.00	(0.11)	0.0%		0.0%
51 kV to 219 kV	(3.77)	0.00	(3.77)	(4.10)	0.00	(4.10)	-8.8%		-8.8%
220 kV and Above	(6.32)	0.00	(6.32)	(7.21)	0.00	(7.21)	-14.1%		-14.1%
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									
TOU-8-S-RTP (Below 2kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.01994	Variable*	Variable*	0.02777	Variable*	Variable*	39.3%		
Mid-peak				0.02777	Variable*	Variable*			
Off-Peak				0.02777	Variable*	Variable*			
Winter Season									
Mid-peak				0.02777	Variable*	Variable*			
Off-Peak				0.02777	Variable*	Variable*			
Super-Off-Peak				0.02777	Variable*	Variable*			
Customer Charge - $/month	658.18	0.00	658.18	459.50	0.00	459.50	-30.2%		-30.2%
Facilities Related Demand Charge - $/kW									
Demand Charge (Excess FRD) - $/kW	19.02	0.00	19.02	12.70	0.00	12.70	-33.2%		-33.2%
Standby (CRC) - $/kW	9.80	0.00	9.80	10.45	0.00	10.45	6.6%		6.6%
Time Related Demand Charge - $/kW									
Backup demand									
Summer Season									
On-Peak				7.09	0.00	7.09			
Mid-Peak				0.00	0.00	0.00			
Supplemental demand Summer Season									
On-Peak				9.85	0.00	9.85			
Mid-Peak				0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.55	0.00	0.55	0.60	0.00	0.60	9.1%		9.1%

	January 2018 Rates			Proposed 2018 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-8-S-RTP (From 2 kV to 50 kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.01918	Variable*	Variable*	0.02817	Variable*	Variable*	46.9%		
Mid-peak				0.02817	Variable*	Variable*			
Off-Peak				0.02817	Variable*	Variable*			
Winter Season									
Mid-peak				0.02817	Variable*	Variable*			
Off-Peak				0.02817	Variable*	Variable*			
Super-Off-Peak				0.02817	Variable*	Variable*			
Customer Charge - $/month	658.18	0.00	658.18	244.75	0.00	244.75	-62.8%		-62.8%
Facilities Related Demand Charge - $/kW									
Demand Charge (Excess FRD) - $/kW	18.80	0.00	18.80	12.48	0.00	12.48	-33.6%		-33.6%
Standby (CRC) - $/kW	8.67	0.00	8.67	6.89	0.00	6.89			
Time Related Demand Charge - $/kW									
Backup demand									
Summer Season									
On-Peak				5.29	0.00	5.29			
Mid-Peak				0.00	0.00	0.00			
Supplemental demand Summer Season									
On-Peak				9.36	0.00	9.36			
Mid-Peak				0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.55	0.00	0.55	0.60	0.00	0.60	9.1%		9.1%
TOU-8-S-RTP (Above 50 kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.01623	Variable*	Variable*	0.01680	Variable*	Variable*	3.5%		
Mid-peak				0.01680	Variable*	Variable*			
Off-Peak				0.01680	Variable*	Variable*			
Winter Season									
Mid-peak				0.01680	Variable*	Variable*			
Off-Peak				0.01680	Variable*	Variable*			
Super-Off-Peak				0.01680	Variable*	Variable*			
Customer Charge - $/month	2,112.27	0.00	2,112.27	1,624.75	0.00	1,624.75	-23.1%		-23.1%
Facilities Related Demand Charge - $/kW									
Demand Charge (Excess FRD) - $/kW	8.19	0.00	8.19	6.39	0.00	6.39	-22.0%		-22.0%
Standby (CRC) - $/kW	0.98	0.00	0.98	0.77	0.00	0.77	-21.4%		-21.4%
Time Related Demand Charge - $/kW									
Backup demand									
Summer Season									
On-Peak				1.10	0.00	1.10			
Mid-Peak				0.00	0.00	0.00			
Supplemental demand Summer Season									
On-Peak				4.60	0.00	4.60			
Mid-Peak				0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.47	0.00	0.47	0.54	0.00	0.54	14.9%		14.9%
Voltage Discount, 220 kV and above									
Facilities Related Demand (Excess FRD) - $k/W	(3.40)	0.00	(3.40)	(1.92)	0.00	(1.92)	43.5%		43.5%
Time-Related Demand - $/kW									
Supplemental Summer on & Winter Mid				(1.92)	0.00	(1.92)			
Backup Summer on & Winter Mid				(0.41)	0.00	(0.41)			
Energy - $/kWh	0.00000	(0.00064)	(0.00064)	0.00000	(0.00056)	(0.00056)		12.5%	12.5%
Standby (CRC) - $/kW	(0.44)	0.00	(0.44)	(0.27)	0.00	(0.27)	38.6%		38.6%

	January 2018 Rates			Proposed 2018 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
Optional CPP Rider < 200 kW									
CPP Event Energy Charge - $/kWh									
TOU-GS-2	0.00000	1.37453	1.37453	0.00000	0.40000	0.40000		-70.9%	-70.9%
Summer Non-Event Demand Credit - $/kW									
TOU-GS-2 (On-Peak Dmand)	0.00	(10.75)	(10.75)	0.00	(3.42)	(3.42)		68.2%	68.2%
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	0.40000	0.40000		-70.9%	-70.9%
Summer On Peak Demand Credit - $/kW	0.00	(11.44)	(11.44)	0.00000	(3.77)	(3.77)		67.0%	67.0%
TOU-8-SEC									
2 p.m. to 6 p.m CPP Event Energy Charge - $/kWh	0.00000	1.37453	1.37453	0.00000	0.40000	0.40000		-70.9%	-70.9%
Summer On Peak Demand Credit - $/kW	0.00	(11.93)	(11.93)	0.00000	(4.11)	(4.11)		65.5%	65.5%
TOU-8-PRI									
2 p.m. to 6 p.m CPP Event Energy Charge - $/kWh	0.00000	1.34519	1.34519	0.00000	0.40000	0.40000		-70.3%	-70.3%
Summer On Peak Demand Credit - $/kW	0.00	(11.82)	(11.82)	0.00000	(4.26)	(4.26)		64.0%	64.0%
TOU-8-SUB									
2 p.m. to 6 p.m CPP Event Energy Charge - $/kWh	0.00000	1.29359	1.29359	0.00000	0.40000	0.40000		-69.1%	-69.1%
Summer On Peak Demand Credit - $/kW	0.00	(11.58)	(11.58)	0.00000	(4.22)	(4.22)		63.6%	63.6%

Appendix C

Updated TOU Periods

	Updated TOU Periods (D.18-07-006)
SUMMER	
On-Peak	4pm-9pm (weekdays)
Mid-Peak	4pm-9pm (weekends)
Off-Peak	All except 4pm-9pm (all days)
Super-Off-Peak	n/a
WINTER	
On-Peak	n/a
Mid-Peak	4pm-9pm (all days)
Off-Peak	9pm-8am (all days)
Super-Off-Peak	8am-4pm (all days)