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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

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

AMENDMENT OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) AND SETTLING PARTIES TO MARGINAL COST AND REVENUE ALLOCATION SETTLEMENT AGREEMENT

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Dated: **September 9, 2015**

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Pursuant to Rule 1.12 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] hereby submits an amendment to Appendix A of the Marginal Cost and Revenue Allocation Settlement Agreement (Settlement Agreement), which Settlement Agreement was attached to Settling Parties' August 14, 2014 Motion for Adoption of Marginal Cost and Revenue Allocation Settlement Agreement. At the request of the assigned Administrative Law Judge at the August 18, 2015 workshop, the document attached hereto, titled "Revised Appendix A," contains a new column (second front the left margin) showing "Current Treatment (*i.e.*, 2012 GRC Settled Position)." The revised Appendix A also includes non-substantive edits and clarifying edits to the settled outcomes. The attached Revised

[1] The Settling Parties are SCE; The Utility Reform Network (TURN); the Office of Ratepayer Advocates (ORA); California Farm Bureau Federation (CFBF); Agricultural Energy Consumers Association (AECA); Southern California Fluid Milk Handlers (SCFMH); Federal Executive Agencies (FEA); California Manufacturers & Technology Association (CMTA); California Large Energy Consumers Association (CLECA); Energy Producers and Users Coalition (EPUC); Energy Users Forum (EUF); California City-County Street Light Association (CAL-SLA); Solar Energy Industries Association (SEIA); and Direct Access Customer Coalition (DACC). Pursuant to Rule 1.8(d), SCE has been authorized to file this amendment on behalf of the Settling Parties.

Appendix A is intended to supplant the originally filed Appendix A to the Settlement Agreement in its entirety.

Respectfully submitted,

JANET S. COMBS
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And on behalf of the Settling Parties.

September 9, 2015

Revised Appendix A
Comparison Of Party Positions and Settlement

Marginal Costs

Issue	Current Treatment (*i.e.*, 2012 GRC Settled Position	SCE	ORA	TURN	CLECA/CMTA	CFBF	AECA	SEIA	EUF	EPUC	FEA	Others	2015 GRC Settled Position
Generation Capacity (Shown in $/kW-year without Resource Adequacy adder.)	$114	$122.85, based on deferral value of a Simple Cycle GE 7FA proxy with 10% Discount Rate, net of energy rents.	$72.79 with adjusted deferral capacity from year 2020 to 2021, sets discount rate at 7.9% and removes energy rents.	$67.91 to reflect a lower cost of a combustion turbine with a longer lifespan and lower utility return on equity and debt of 7.9%. Supports removal of energy rents.	$127.35/kW-year. Does not object to SCE's Marginal Generation Capacity Cost with some modification (e.g. adds insurance). CLECA supports including the reserve margin adjustment factor for revenue allocation purposes and opposes subtracting energy rents above a minimal level.	$210, based on the CEC's publicly vetted, mid-case CT cost estimate.	SCE's Capacity marginal cost should be discounted by 40.3% to $71.96 to account for deferred need to 2023 according to the CAISO forecast. Capacity values should differ among rate classes due to differences in projected growth rates that accelerate or delay the need for new capacity.	$160 based on higher capital costs. Supports using full annualized fixed costs of a LM6000 Combustion Turbine.	Supports SCE's proposed value of $122.85.	$199.48 to reflect the full annual deferral value of a LM6000 CT, opposes removal of energy rents. Include adjustments for A&G (0.77%) and Insurance.	$129.50, Generally agrees with SCE's proposal except rents should be included.		$108
Marginal Energy (¢/kWh)	Use SCE production cost model, but use $4.47/MMBtu gas price and model proposed by EPUC to spread costs to TOU periods. Summer On: 5.5¢ Mid: 4.2¢ Off: 2.9¢ Winter Mid: 4.6¢ Off: 3.5¢	5.33¢, utilizes 2015-2017 average natural gas price $4.64/MMBtu Does not incorporate TOU shaping of RPS.	Supports SCE's proposed marginal energy costs of 5.33¢	5.37¢, includes ancillary services and incorporates TOU shaping of RPS.	3.91 ¢ **average MEC** to reflect updated energy and gas forward prices. Opposes inclusion of RPS costs. If included, value capacity at CT cost. Attribute above-market costs equally to capacity and energy, which sets the average RPS adder at 0.36 c/kWh. If included, shape RPS adder by TOU based on output of incremental RPS projects, which differentiates the RPS adder by TOU period.	Opposes inclusion of SCE's proposed RPS adder as not reflecting SCE's current marginal costs for renewable power. If included, RPS adder should be corrected to reflect current market prices for California's tradable RECs.	Calculate the present value of the stream of MECs over the relevant planning horizon. For each additional kilowatt-hour of energy, at least 33% of that energy must come from a renewable resource, and not natural gas. The gas MEC does not reflect either the expected future fuel price or the risk premium added to long-term contracts.	Utilizes updated prices for 2015-2017 given drop in fossil fuel prices combined with hourly price profiles CAISO day-ahead market. Supports TOU shaping of RPS adder, combining energy and capacity factors.	Update to lower gas price and do not spread additional RPS-eligible energy costs across all TOU periods. No specific marginal energy cost was calculated.		Reduce Marginal Energy Cost by 20% and update prices for gas and wholesale electricity markets No comment on TOU shaping of RPS.		Summer On: 5.8¢ Mid:4.6¢ Off: 3.2¢ Winter Mid: 4.6¢ Off: 3.7¢ Updated 2015-2017 average price $3.60/MMBtu 0.6¢ RPS Adder
Customer MC Method	50/50 SCE NCO-RECC (adjusted to use TURN's RECC input values with the exception of taxes and A&G, and the NCO replacement factor is set at 3.1 percent.)	RECC	NCO	NCO	RECC (like SCE).	NCO, modified from ORA's proposal (includes SCE's customer growth forecast and replacement rates and excludes interval data management costs for IDR meters).	Growth-based marginal cost (assigns costs to class, differentiated growth area.). Overall costs discounted by 22% on average due to deferred need for replacements and added services. Installation costs should differ among rate classes due to differences in projected growth rates that accelerate or delay the need for new capacity.	No Comment	RECC		RECC	CAL-SLA: NCO DACC: RECC	50/50 TURN NCO-RECC

Issue	Current Treatment (*i.e.*, 2012 GRC Settled Position	SCE	ORA	TURN	CLECA/CMTA	CFBF	AECA	SEIA	EUF	EPUC	FEA	Others	2015 GRC Settled Position
Distribution Demand MC ($/kW-year)	Marginal Sub-transmission cost = $34 Marginal Distribution cost= $84	Marginal Sub-transmission cost = $37.58 Marginal Distribution cost = $89.29	Marginal Sub-transmission cost = $29.92 Marginal Distribution cost = $99.90	Marginal sub-transmission cost=$36.33 ($52.23 with RA scalar) Marginal Distribution cost=$130.63($185.77 with RA scalar)	Marginal sub-transmission cost= $28.22 Marginal Distribution cost= $71.94. Both based on traditional regression method with no adjustments to load.	Supports SCEs proposed marginal costs. Alternatively, if PUC adopts recorded vs. planned, CFBF recommends using historical data only, resulting in marginal sub-transmission cost = $35.11 Marginal distribution cost= $96.31	Overall costs discounted by 12.1% on average due to deferred need for substation capacity. Calculate difference in class-specific Substation Peak Growth Rates. Apply the division-based present value factor for each customer class to secondary, primary and new business marginal distribution capacity costs. Agricultural "effective demand factors" (EDFs) have been reduced by 16% to account for average residential usage when weighted by the number of agricultural customers per substation is 12.5% higher than without such weighting in EDF analysis.	SCE should be order to perform a time-differentiated distribution marginal cost study, including whether a portion of SCE's sub-transmission costs should be allocated on a TOU basis (similar to PG&E and SDG&E) by March 1, 2016.	Supports SCE's marginal distribution marginal costs.		Supports SCE's proposed distribution demand marginal cost.		Marginal Sub-transmission cost: $29.92 Marginal Distribution cost: $99.90 SCE to perform time-differentiated distribution marginal cost study by March 1, 2016.
TOU Periods and Critical Peak Pricing (CPP)	No change to TOU periods. Default CPP issue for small and medium commercial customers was addressed in a different settlement by a recommendation to defer indefinitely (a provision the Commission rejected).	Consider modifying TOU periods in 2018 rate case Default CPP in April 2017	No Comment on modification of TOU periods Supports proposed delay of CPP migration to April 2017 with additional ME&O and reporting requirements.	No Comment on modification of TOU periods	TOU periods should be revised no later than the 2015 rate design window based on forecast change in net load shapes.	Load shape forecasts for customers recently migrated to TOU rates may need to be adjusted to reflect a shift in usage away from on-peak period Supports SCE CPP proposal but requests further delay to January/February 2018 to avoid transition during harvest season.	No Comment on modification of TOU periods Supports proposed delay of CPP migration	No Comment on modification of TOU periods or CPP	SCE should revisit definition of TOU periods, which should also consider the Net Demand for each hour and intra-hours using CAISO definition of Net Demand.	No Comment on modification of TOU periods or CPP	No Comment on modification of TOU periods or CPP	N/A	SCE to propose TOU periods in SCE's 2016 RDW Defer CPP migration to 2018 to align with the redefinition of TOU periods.

Revenue Allocation

Issue	2012 GRC Settled Position	SCE	ORA	TURN	CLECA/ CMTA	CFBF	AECA	DACC	EUF	CAL-SLA	2015 GRC Settled Position
Revenue Allocation Cap	Distribution cap of +4% of revenues; Generation cap of +1.5% of revenues. Bundled ag rate groups treated as single class for capping with a compromise allocation approximately midway between SCE's proposal of two separate classes (one capped, one uncapped) and TURN's proposal of a single class. Ag rates for subclasses determined in Ag Rate Design Settlement. All Standby classes set at 11% bundled increase because of anomalies in capping process. Rate floor of 6% less than system average adopted (applies to GS-1 and to streetlights excluding facilities charges).	SCE did not propose capping.	Supports use of caps (% not specified).	Recommends caps of ≤ 5%, use of rate floors, and any customer class receiving >8% less than the system average (uncapped) should be capped at < 8% system average or two thirds of the uncapped decrease. Entire AG&P class should be treated as single class for capping and should be capped at cost-base allocation as a whole.	Supports capping concept in theory. However, CLECA/CMTA proposed allocation is uncapped.	Supports capping. However, CFBF does not include a specific capping proposal. If capping is implemented, it should be separate for TOU-PA-2 and TOU-PA-3 customer groups.	Cap AG&P rates at 5% decrease to recognize need to keep rates stable while correcting previous agricultural cost overestimation.	Any capping for generation rev req. allocation should occur in generation rates.	Supports capping. However, caps cannot disproportionately disadvantage one group of customers, be unequitable to DA/CCAs, or unfairly advantage a select set of customers.	Supports concept of caps.	±3% distribution revenues, ±2% generation revenues
Distribution Revenues	Non-allocated revenues will be assigned directly to the rate groups responsible for incurring the costs.	Allocate by marginal cost based distribution allocator factor after removing non-allocated revenues.	Allocate by distribution allocation factor derived by EPMC.	Allocate Non-CARE PPP based on each rate group's percentage share of system revenues for bundled-service and DA customers, with generation revenues for DA customers imputed. Allocate 37% of AMI costs using EPMC w/ imputed DA. P&B associated with Public Purpose Programs 76.3% distribution and 23% generation.	Supports SCE proposal to allocate costs of programs that cannot be functionalized into standard categories (CSI, SGIP, EE, EPIC, DR, AMI, Nuclear Decommissioning, and CARE).		Ag should bear little or none of the costs incurred by SCE in support of Rule 20. Residential and commercial customers should bear most of the costs associated with these conversions and at minimum these expenses should be captured within the customer class inducing them.	No Comment	Opposes SCE's proposal to allocate revenue shortfall caused by PTR across all customers' distribution rates because PTR is not available to DA/CCA customers. - Reduce incentive levels for Summer Discount Plan (SDP) options to avoid unfair subsidy in distribution rates by bundled service DA and CCA customers.	Supports EPMC for rev allocation method for distribution revenues	Non-allocated revenues will be assigned directly to the rate groups responsible for incurring the costs.
Generation Revenues	Allocate to rate groups based on the generation functional allocators.	Allocate to rate groups based on the generation functional allocators Interruptible rate program credits proposed at capacity value of $85 kW-year.	Allocate by generation allocation factor derived by EPMC.		Allocate by generation allocation factor. Recommends **$115.14**/kW-year for BIP incentives. Apply caps to incentives if credit exceeds value of capacity reflected in demand charges.					Supports EPMC for rev allocation method for generation revenues.	Allocate to rate groups based on the generation functional allocators.

Issue	2012 GRC Settled Position	SCE	ORA	TURN	CLECA/ CMTA	CFBF	AECA	DACC	EUF	CAL-SLA	2015 GRC Settled Position
Demand Response Programs	Capped distribution revenue allocators, applied to DR revenue requirement, shall be modified such that 50 percent of DR revenue requirement will be allocated by each rate group's proportional share of system revenues, with generation revenues for DA/CCA customers imputed as bundled customers and the remaining 50 percent will be allocated by uncapped distribution revenue allocators.	Propose to assign PTR and Interruptible credits to be recovered from all rate groups in distribution rates. SCE would refine 98/2 split once it has additional experience with the program design changes implemented for PTR.		DR (including DR Capacity Contracts and DR Purchase Agreement Admin) should be allocated on the basis of the EPMC Generation with Imputed DA allocator Recommends allocating CSI and SGIP programs allocated on the basis of the CARE allocation factor (equal cents per kWh without CARE and streetlights). Ref: (p. 46)	Allocate costs for interruptible programs to all rate groups whether bundled, DA, or CCA. Allocate 2% of PTR revenue shortfall to non-residential customers and 98% to residential class.				Opposes SCE's proposal to allocate revenue shortfall caused by PTR across all customers' distribution rates.		Collared distribution revenue allocators, applied to DR revenue requirement, shall be modified such that 50 percent of DR revenue requirement will be allocated by each rate group's proportional share of system revenues, with generation revenues for DA/CCA customers imputed as bundled customers and the remaining 50 percent will be allocated by uncollared distribution revenue allocators.
Nuclear Decommissioning	Allocate decommissioning revenue to all rate groups, based on energy consumption reflecting total retail sales, recovered as a cents per kilowatt-hour charge designated in SCE's tariffs as the NDC.	NDC revenue requirement allocated to all retail customers to rate groups on an equal cents/kWh basis. Retain current allocation for PPP, assigning these revenues to rate groups on a system average percentage.			Accepts SCE's proposal to allocate on equal-cents-per kWh basis per prior CPUC precedent.						Allocate decommissioning revenue to all rate groups, based on energy consumption reflecting total retail sales, recovered as a cents per kilowatt-hour charge designated in SCE's tariffs as the NDC.
Public Purpose Program (PPP)	Allocate based on each rate group's percentage share of system revenues for bundled-service and DA customers, with generation revenues imputed for DA. CARE allocated to rate groups on an equal cents per kWh basis including DA sales, but excluding the kWh usage of CARE and Street Light customers.	Assign revenues to rate groups on a System Average Percent with generation revenues imputed for DA.		Allocate Non-CARE PPP based on each rate group's percentage share of system revenues for bundled-service and DA customers, with generation revenues for DA customers imputed.	Assign revenues based on SAPC allocation. Allocate CARE costs on an equal- cents- per- kWh basis, per the statute.						Allocate based on each rate group's percentage share of system revenues for bundled-service and DA customers, with generation revenues imputed for DA CARE allocated to rate groups on an equal cents per kWh basis including DA sales, but excluding the kWh usage of CARE and Street Light customers.
Non-Coincident Peak (NCP) Demand	N/A	SCE proposed Non-Coincident Peak (NCP) Demand value of 0.56kW and 0.36kW based on 2010-2012 average.				Proposes RA balancing account to track actual average rate impacts from Phase 2 compared to the allocation-based increase adopted by Commission and return under/over collections in subsequent GRC Non-coincident peak demand value of 0.52 kW per MWh for AG&P less than 200kW and 0.33 kW per MWh for	Agricultural demand reduced 16% to include aggregation potential with tariff redesign.				Adopt CFBF adjustment to Non-coincident peak demand value, with NCP values of 0.52 kW per MWh for AG&P less than 200 kW and 0.33 kW per MWh for AG&P greater than or equal to 200 kW (compared to SCE's recommended values of 0.56 kW per MWh and 0.36 kW per MWh, respectively).

Issue	2012 GRC Settled Position	SCE	ORA	TURN	CLECA/ CMTA	CFBF	AECA	DACC	EUF	CAL-SLA	2015 GRC Settled Position
						AG&P greater than or equal to 200 kW (based on 7-year averages spanning 2007-2013).					
Other							Propose RA balancing account to track year-to-year actual agricultural revenues against forecasted. Due to non-linearities in revenue collection from agricultural customers, net revenue differences do not balance to zero as water conditions change.				