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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Assess Peak Electricity Usage Patterns and Consider Appropriate Time Periods for Future Time-of-Use Rates and Energy Resource Contract Payments.	R.15-12-012 (Filed December 17, 2015)

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) REPLY COMMENTS TO SCOPING QUESTIONS FILED ON JUNE 27, 2016

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Dated: **July 19, 2016**

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I.

INTRODUCTION

Pursuant to the schedule adopted in the May 3, 2016 "Scoping Memo and Ruling of Assigned Commissioner and Assigned Administrative Law Judge" (Scoping Memo) and later revised in the May 25, 2016 Administrative Law Judge Ruling, Southern California Edison Company (SCE) provides its reply to opening comments filed by parties on June 27, 2016.[1] SCE agrees with parties that this Rulemaking should focus on developing broad guiding principles regarding the data requirements and the general methodology necessary to support a time-of-use (TOU) period adjustment proposal.[2]

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1 Due to the number and complexity of opening comments filed on June 27, 2016, SCE will not respond to all such comments. That should not be interpreted either as agreement or disagreement with specific comments made by other parties.

2 PG&E Comments at p. 2; ORA Comments at p. 7.

II.

RESPONSE TO COMMENTS

A. Parties Are in General Alignment on the Guiding Principles that Should Be Used to Establish TOU Periods

SCE notes that nearly all of the parties who submitted comments on the May 3, 2016 Scoping Memo agree that utility-specific marginal costs should be the primary basis of TOU period proposals,[3] and observes that the cost drivers for the three major IOUs, as presented in the IOUs' April 29, 2016 responses, are largely consistent.[4] While SCE appreciates the opportunity to discuss the nuanced differences in marginal cost methodologies that this proceeding has afforded, SCE agrees with SEIA that the "Commission should not [here] constrain the methodologies used to calculate or to allocate marginal costs,"[5] and should allow parties to continue to vet these issues in their individual ratesetting proceedings. While SCE will continue to assess TOU periods in its GRC Phase 2 proceedings, SCE does not agree with SEIA's recommendation to *necessarily* restrict the *definition* of TOU periods to IOU GRC Phase 2 proceedings. SCE notes that SEIA's recommendation, if interpreted to apply to SCE, does not comport with SCE's 2015 GRC Phase 2 Marginal Cost and Revenue Allocation Settlement Agreement, to which SEIA is a signatory, which obligates SCE to file, in a RDW application, TOU period analysis and a proposal, if warranted, for new default TOU periods.

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[3] PG&E Comments at p. 5; SDG&E Comments at p. 8; ORA Comments at p. 5; CLECA at p. 2; SEIA Comments at p. 6, etc.

[4] Consistent with this evidence, SDG&E recently proposed a summer (June through September, inclusive) on-peak period from 4-9 p.m. on weekdays (See A.15-04-012). Similarly, PG&E, in their recently filed 2017 GRC Phase 2 proceeding, proposed a shortening of its summer season from May-October to June-September, and an on-peak summer period from 5-10 p.m. on weekdays (See A.16-06-013). Lastly, SCE's Updated TOU Period Analysis, filed July 11, 2016, also demonstrates that the four summer months of June-September have the highest average Total Generation Marginal Cost, and that the five highest average total marginal cost hours are between 4-9p.m. on summer weekdays.

[5] SEIA Comments at p.11.

Parties also generally agreed that, while the primary goal of correctly defined TOU periods is to send accurate price signals that address the challenging system conditions identified by the CAISO in its TOU Analysis,[6] the final determination of TOU periods should also consider customers' ability to understand and respond to the new TOU periods. As the Green Power Institute (GPI) recognized, "the determination of appropriate TOU periods is as much an art as it is a science. The art is to balance considerations of simplicity and practicality with considerations of accuracy."[7] Parties identified potential adjustments that would simplify cost-based TOU periods and encourage customer acceptance, such as: maintaining the existing two-season definition,[8] using consistent period definitions across seasons such that the highest cost winter period aligns with the highest cost summer period,[9] or shortening the peak period by an hour based on customer preference data.[10] Parties also noted that optional rates, with features such as dynamic pricing and more complex TOU period definitions, remain the most effective way to incent significant load shift and to "address challenging system conditions in a more focused way."[11] SCE agrees with this two-pronged approach of developing customer acceptance-informed default TOU periods and offering optional rates with alternate, but also cost-based, TOU periods to customers who are able to adapt, but maintains that such proposals should be considered within the context of individual IOU rate-setting proceedings, and not here in this OIR.

B. <u>Data and Analysis Need to be Sufficiently "Forward Looking"</u>

While all parties agree that TOU period definitions should be maintained for at least five years, or roughly two General Rate Case cycles, to minimize customer confusion, parties

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6 CAISO TOU Report and Analysis (CAISO TOU Analysis), dated and filed on January 22, 2016.
7 GPI Comments at p.4.
8 CLECA Comments at p.17; SEIA at p. 22; CFBF Comments at p.7.
9 CLECA Comments at p. 17.
10 PG&E Comments at p. 30.
11 SEIA Comments at p.13.

disagree on the time-frame on which supporting analyses should be based in setting the TOU periods. As CLECA observed in its January 15, 2016 Response to the Rulemaking Questions, "[i]f TOU periods are forward-looking, it ought to be possible to fix the TOU periods for some reasonable period of time ***without risking the provision of significantly incorrect price signals.***"[12] SCE agrees, and believes that SEIA's "mid-point" proposal to use forecast conditions in "the middle of the five year period"[13] is a short-sighted approach that will result in incorrect price signals in the latter years and could require a subsequent, too-soon update to the TOU periods.[14] While SEIA, in principle, agrees that changing TOU periods frequently is not ideal and will result in an "excessive expenditure of Commission and stakeholder resources, [and cause] customers [to] be in a constant state of uncertainty,"[15] its proposal to use a near-term forecast essentially guarantees that TOU periods will need to be reset.

As parties have observed, the initial resetting of the TOU periods will likely be significant, and it will be "as if the blocks of times customers have become familiar with were a deck of cards, which has been shuffled."[16] The conditions necessitating today's discussion, specifically, the impact on IOU load profiles of the increase in the renewables portfolio standard (RPS) from 20% in 2010 to 33% in 2020, will be intensified in the near future with the passage of Senate Bill (SB) 350 (50% RPS by 2030) and the continued growth of behind-the-meter (BTM) distributed generation. As such, it is prudent to ***set the TOU periods*** in a way that accounts for these imminent changes and allows the periods to remain stable for the foreseeable future.[17] As Siemens summarizes aptly, "rather than changing the TOU periods, prices can

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[12] CLECA's January 15, 2016 Response to Rulemaking Questions, at pp. 5-6, ***emphasis added***.

[13] SEIA Response at p.10.

[14] SCE notes that although SEIA advocates for a "forward looking mid-point," the analysis included in its Comments uses recorded 2015 data. SCE recommends that any conclusions using "backward-looking" data be disregarded.

[15] SEIA Response at p.31.

[16] CFBF Response at p.9.

[17] The need for durable TOU periods is further amplified when considering the scheduled 2019 default of residential customers to TOU rates and the need for a resilient education and outreach strategy.

change over time to reflect changes in underlying costs and in market prices for the applicable hours."[18] Indeed, because short-run load and natural gas forecasts, and in turn energy price forecasts, will continue to be used to help determine revenue allocation and rate designs in each IOU's GRC Phase 2 proceedings, the actual time-varying rates will reflect more near-term conditions, with prices shifting gradually as the changes described in this section materialize.

1. Changes to Marginal Generation Costs Patterns

In the March 17, 2016 Ruling Requiring Supplemental Information Filings (March 17 Ruling), the ALJ requested that the CAISO TOU Analysis, which included the forecasted "net load (L4, as identified in Table 1 of the Scoping Memo)"[19] expected in the year 2021 based on data collected prior to the passage of SB 350,[20] be "re-run" to include updated 2021 and 2024 RPS assumptions.[21] Although the CAISO has since indicated that the updated 2024 analysis will not be available in time for consideration in this OIR, SCE believes that it is critical that all data and analysis used to support TOU period changes include the impact of moving from 33% to 50% RPS requirements. SCE agrees with SEIA's observation that "the TOU periods selected should address those times of challenging system operating conditions, such as hours of potential over-generation or steep net load up-ramps,"[22,23] and believes that, because those conditions are expected to be exacerbated as more utility-scale renewable

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[18] Siemens Response at p.5.

[19] Net Load is defined as the forecasted hourly system load, less the forecasted electricity production from variable wind and solar resources.

[20] As described in pages 18-21 of the CAISO TOU Analysis, the net load was determined using demand data from the 2013 and 2014 Integrated Energy Policy Reports (IEPR) and load shape and supply data from the 2014 Long Term Procurement Plan (LTPP) proceeding.

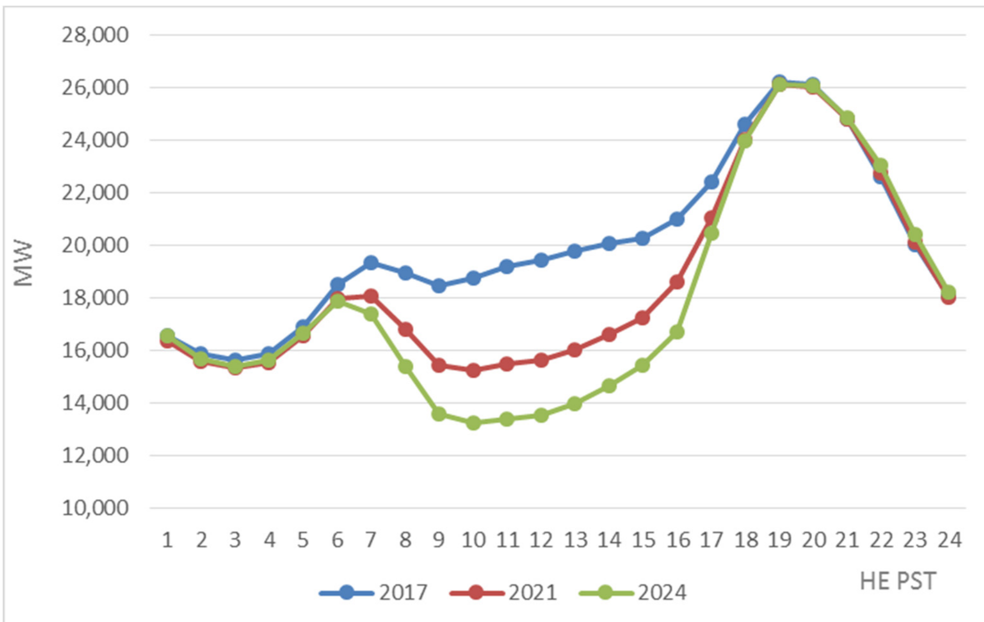
[21] March 17 Ruling at p. 2.

[22] SEIA Comments at p.6.

[23] SEIA generally identifies the steepest up-ramp hours as "the hours prior to the net load peak." SCE clarifies that the ramp often extends from the time of low, or lowest, demand to the hour of the net load peak. Including the entire ramp, but not the net peak, in the on-peak period does not address the challenge identified by the CAISO, as it discourages usage during the "duck belly," but encourages usage during the "duck head." Instead, the early hour of the ramp should be grouped together with the other hours in the "belly," thus increasing usage during those hours and decreasing the overall amplitude of the ramp.

generation is added to the grid,[24] it would be hasty to set TOU periods based on data that will quickly become outdated. As can be seen by comparing the 2017, 2021, and 2024 forecasted net loads and forecasted marginal energy costs, data and analysis can quickly become "stale" if it does not account for the impacts of significant policy changes on generation cost drivers.

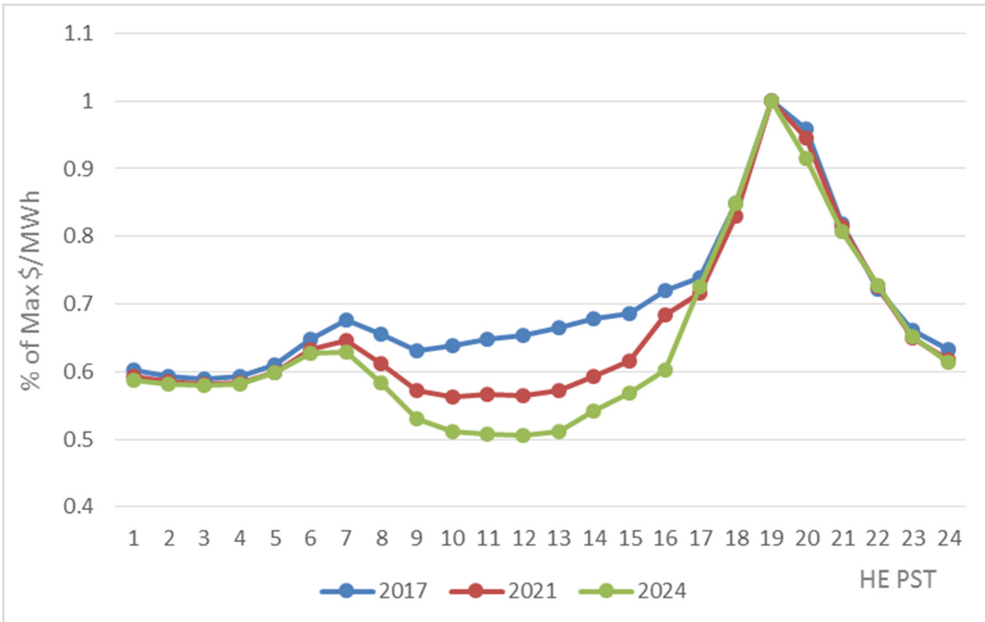
Figure II-1
Comparison of 2017, 2021, and 2024 Average Annual Weekday Net Load by Hour (MW)[25]



24 *See generally* "Beyond 33% Renewables: Grid Integration Policy for a Low-Carbon Future"—A CPUC Staff White Paper at pp. 6-18.

25 Graph illustrates the annual average of hourly CAISO level managed load (or gross load) and RPS resources of the three California IOUs. These hourly forecasts were used as inputs in SCE's PLEXOS model to develop SCE's forecast of marginal energy costs, as submitted on July 11, 2016. Results are shown in Pacific Standard Time (PST).

Figure II-2
Comparison of 2017, 2021, and 2024 Average Annual
Weekday Marginal Energy Costs by Hour – Normalized[26]



2. Changes to Marginal Distribution Cost[27] Patterns

In addition to the changes to the "net-load (L4)" and generation marginal cost curves described above, the shape of the metered (L2) and distribution substation and circuit load (L3), in aggregate known generally as the "managed (or gross) load," will also transform in the near future. As behind-the-meter photovoltaic (PV) installed capacity doubles over the next ten years,[28] the load served at the distribution substation and circuit levels will begin to exhibit the same hourly patterns seen in the system net load. Specifically, as can be seen in Figure II-3 and Figure II-4, the increased penetration of PV could result in the evolution of "mini duck-curves"

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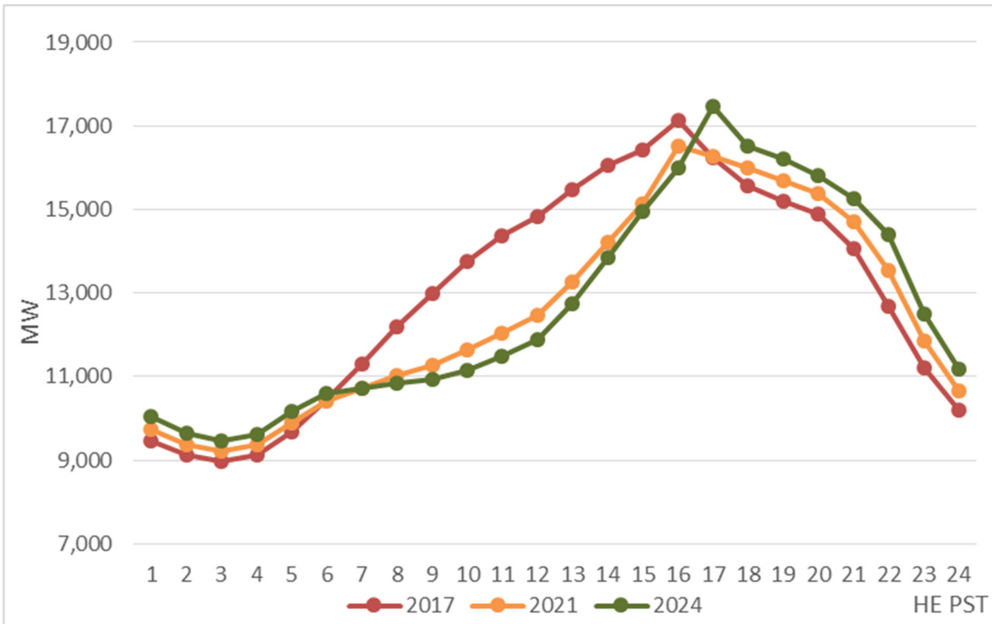
[26] As indicated in the footnote above, the South of Path (SP) 15 marginal energy costs were determined using SCE's PLEXOS model, and were submitted in SCE's July 11, 2016 Amendment to the April 29, 2016 Response. Results are shown in PST.

[27] Parties at the May 5, 2016 and June 8, 2016 workshops acknowledged that only a portion of marginal distribution costs are time-dependent.

[28] *See* the California Energy Demand 2015 Revised "Mid-Demand" Forecast for 2016-2026 estimates of residential PV installed capacity.

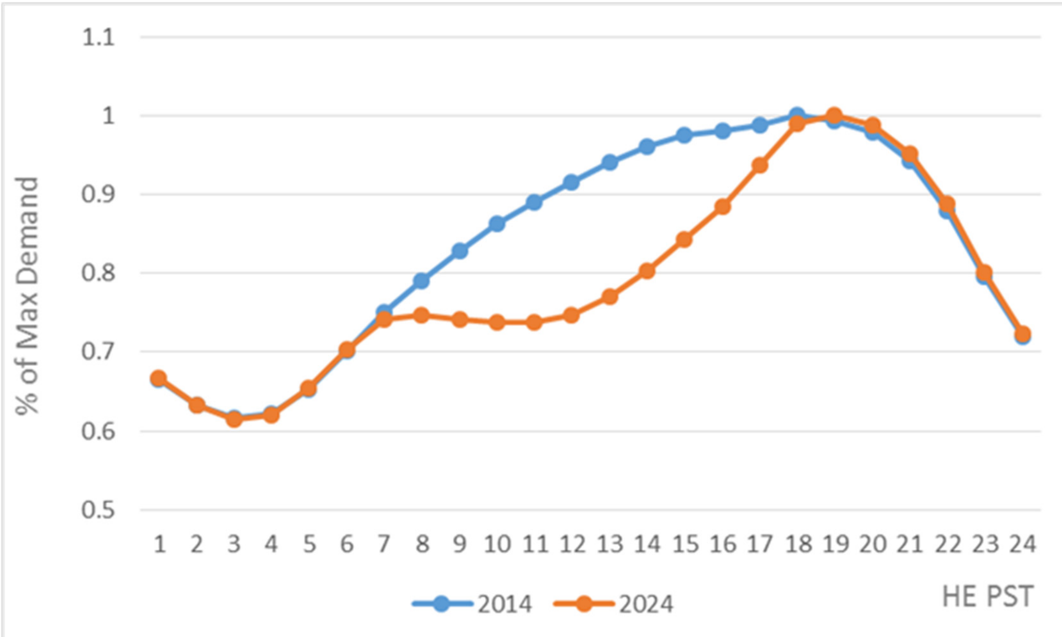
that tend to shift distribution circuit peaks from the mid-afternoon hours, when solar generation output is at its peak, to the evening hours, when solar generation output is low or non-existent.

Figure II-3
2017, 2021, and 2024 Annual SCE Managed (or Gross) Weekday Load By Hour (MW)[29]



[29] Graph illustrates the annual average of hourly CAISO level managed load (or gross load) for SCE. These hourly forecasts were used as inputs in SCE's PLEXOS model to develop SCE's forecast of marginal energy costs, as submitted on July 11, 2016.

Figure II-4
2014 vs. 2024 Average Weekday Circuit Load - Normalized[30]



C. Allowing for Grandfathered TOU Period Definitions is Not a Viable Solution

While many parties agree that "grandfathering" TOU periods is an unattractive option that creates a situation where "costs are shifted to other customers and distort cost-based rates,"[31] SEIA instead argues that "customers should be able to stay on rate schedules with grandfathered TOU periods in order to provide certainty for investments in technology that are intended to respond to TOU period price signals."[32] SEIA, in their justification for a ten-year[33] grandfathering period, claims that existing solar customers who interconnected under existing TOU periods require special treatment to ensure that their investments are protected.[34,35] As the

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30 2024 hourly circuit load was derived by netting expected DG penetration on each circuit in 2024 against circuit specific hourly load in 2014.

31 UCAN Comments at p. 12. *See also* CLECA Comments at pp. 21, PG&E Comments at p.26, SDG&E Comments at p.18.

32 SEIA Comments at p.28.

33 SEIA's proposal actually represents a grandfathering period that exceeds ten years, as it would require the IOU to "phase-in" the new on-peak period by shifting it by one hour per year.

34 SEIA Comments at pp.32-33.

Commission observed in D.15-07-001, rates and rate structures change periodically; however, allowing for grandfathering because those customers "reli[ed] on existing rates and rate structures [is] unreasonable" and perpetuates cost-subsidies and inefficiencies.[36,37] Instead, as suggested in SCE's initial Comments, optional rates with tempered TOU rate differentials or alternate, but also cost-based, TOU periods can be made available for customers who have already made technological investments. Such solutions would provide accurate price signals and prevent cost-shifts between customers, but also ensure that existing solar customers do not experience an abrupt change as they transition to more cost-based TOU periods.

SCE agrees that investments in technologies such as energy efficiency, storage, and solar PV are integral to the development of a clean, cost-effective, and reliable system. However, as alluded to in SCE's response in Section II.B, the way to ensure that ***future*** customer investments in technology do not become quickly outdated is to set the TOU periods on a sufficiently forward-looking basis (*i.e.,* in a way that captures the upcoming known and tangible system changes) so that customers make informed decisions based on predictable TOU periods, ***not*** to set TOU periods based on inefficacious analysis and subsequently rely on complex grandfathering arrangements when that analysis is updated. For this reason, SCE agrees with CLECA's recommendation that "utilities and other entities involved in developments such as solar installations be required to inform customers when they are making investment decisions about the next time TOU periods would be evaluated and potentially (although not assuredly)

Continued from the previous page

35 SCE also notes that SEIA's proposal to grandfather certain TOU periods for one set of customers based on a certain type of investment represents disparate treatment. Many of SCE's customers have spent many millions of dollars on various energy efficiency and/or demand response investments whose value proposition has changed over the years as a result of various TOU rate differential changes. Trying to maintain an equal value proposition over time through a system of rate grandfathering based on out-dated costs would be a logistical nightmare.

36 D.15-07-001 at pp.154-155.

37 In D.15-07-001, the Commission further clarifies that although they allow Net Energy Metering (NEM) customers connecting before July 1, 2017 to maintain their existing NEM structure for 20 years, the underlying tariff and structure is subject to change and may impact the payback period.

changed."[38] Such communication is especially critical today, as customers who take service under the NEM Successor Tariff will be required to take service on a TOU rate whose cost basis is changing. As CAL-SEIA notes, "customers deciding on investments in onsite energy solutions face a great deal of uncertainty…[and should] be cognizant of the fact that rates can and do change."[39]

As observed by GPI, allowing customers to remain on grandfathered TOU periods will encourage "consumers to continue to operate with out-of-date price signals, [and will] virtually ensure suboptimal behavior."[40] Indeed, if one of the purposes of TOU periods is to address the challenging system conditions presented by CAISO in their report, requiring the utilities to offer an option that discourages usage in the early afternoon hours and encourages usage in the early evening hours is certainly contrary to that goal and will exacerbate the conditions the CAISO has sought to address. Such a solution would also diverge from the basic rate design cost-causation principle that SEIA, itself, cites on its website that the "recovery of costs should be related to the reason that the costs were incurred in the first place,"[41] because the timing of the on-peak rates would not be aligned with the timing of the highest costs to serve. Furthermore, maintaining various sets of grandfathered TOU periods, as SEIA recommends,[42] will lead to customer confusion and be an extremely expensive proposition.

D. <u>It is Inappropriate to Include Transmission Costs in TOU period determination</u>

In addition to the generation and distribution marginal costs identified by the Scoping Memo, SEIA asserts that, because transmission system peak usage coincides with system loads,

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38 CLECA Comments at p.20.
39 CAL-SEIA Comments at p.4.
40 GPI Comments at p.7.
41 http://www.seia.org/research-resources/rate-design-guiding-principles-solar-distributed-generation-0
42 SEIA Comments at p.33.

its marginal costs[43] should similarly be considered in TOU period analyses.[44] While it may be true that transmission system peak usage coincides with system demand peaks, most transmission investments today are not directly related to peak load growth, but are primarily used to support renewable integration[45] and contingency-driven system reliability needs.[46] As described in the 2015-16 ISO Transmission Plan, the majority of the proposed projects support general power flow on the transmission system and are intended to address issues such as: over generation, congestion, frequency stabilization, and the seasonal power flow during on-peak and low load spring times. Indeed, the Federal Energy Regulatory Commission's (FERC) use of the "12 (monthly) Coincident Peak (CP)" methodology,[47] which assigns the appropriate load weight to each calendar month, to allocate transmission costs among classes of customers demonstrates its recognition that transmission costs ***are generally incurred to serve year-round needs.***[48] For these reasons, and because transmission is FERC-jurisdictional and not CPUC-jurisdictional, SEIA's proposal to include transmission marginal costs in TOU-period analyses should be rejected.[49]

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43 SCE also notes that the FERC, which governs all transmission-related activity, does not utilize a marginal cost methodology in its ratemaking proceedings. As such, there is no adopted definition, much less quantification, of "transmission marginal costs."

44 SEIA Comments at pp.17-18.

45 Although SEIA appropriately excludes the costs associated with transmission expansions designed to access RPS resources, its analysis assumes that all remaining transmission "marginal" costs are associated with load and demand growth.

46 2015-2016 CAISO Transmission Plan: http://www.caiso.com/Documents/Board-Approved2015-2016TransmissionPlan.pdf.

47 Transmission revenues are allocated to each rate group based on the sum of their monthly coincident loads at the time of the monthly system peaks as compared to the sum of the monthly system peak loads

48 Also of note is the fact that of the latest three years of 12-CPs analyzed (2012-14), 15 of 36 months, or 42%, occurred during the hours of 6-7 p.m. Higher influx of distributed generation will tend to push these peaks even later in the day.

49 Furthermore, as discussed in Footnote 14, SEIA's use of 2015 data to support its marginal costs and hourly allocations should be disregarded, as it fails to account for significant upcoming changes to gross load shapes.

E. The Commission Should Disregard SEIA's Proposal to Consider May and October as Summer Months

Although the Scoping Memo states that this proceeding is not intended to set the TOU periods or seasons,[50] SEIA nevertheless includes its proposal and evidence that May and October be included in the summer season.[51] SEIA justifies the use of a longer, six-month summer season (May through October) based on historical weather analysis and the expected "longer and hotter summers" resulting from climate change.[52] However, as SEIA itself acknowledges, TOU periods and seasons should be set based on patterns in marginal costs,[53] not on weather.

While SCE agrees with SEIA's assessment that "May and October are now much like June in terms of the frequency of very hot days," SCE disagrees that those hot May and October days "cause peak electric demand."[54] As described in SCE's GRC Phase 2 Testimony,[55] SCE has historically used a "Top 100 Hours" study[56] to determine each rate groups' contribution during the hours of peak electric demand, and allocates marginal generation capacity costs accordingly. As can be seen in Table II-1 below, which examines the same 30 year historical period included in SEIA's analysis,[57] some isolated hot days in May and October does not necessarily translate to an increased frequency of system peak hours in those months,[58] and certainly does not justify the inclusion of May and October in the summer season.

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[50] *See generally* Scoping Memo at p.8.

[51] SEIA Comments at p.25.

[52] SEIA Comments at p.24. Notably, the California Energy Commission report cited by SEIA (p.7 at http://www.energy.ca.gov/2012publications/CEC-500-2012-007/CEC-500-2012-007.pdf) looks at very long term impacts of climate change (e.g. year 2100). SCE continues to recommend using 2024 as a more reasonably distant forward looking horizon of system conditions.

[53] SEIA Comments at p.6.

[54] SEIA Comments at p.25.

[55] *See generally,* A.14-06-014 Volume 03.

[56] SCE uses a "top 100" hours study to soften the impact of any specific peak hour on such an important cost allocator.

[57] SEIA Comments at p.25.

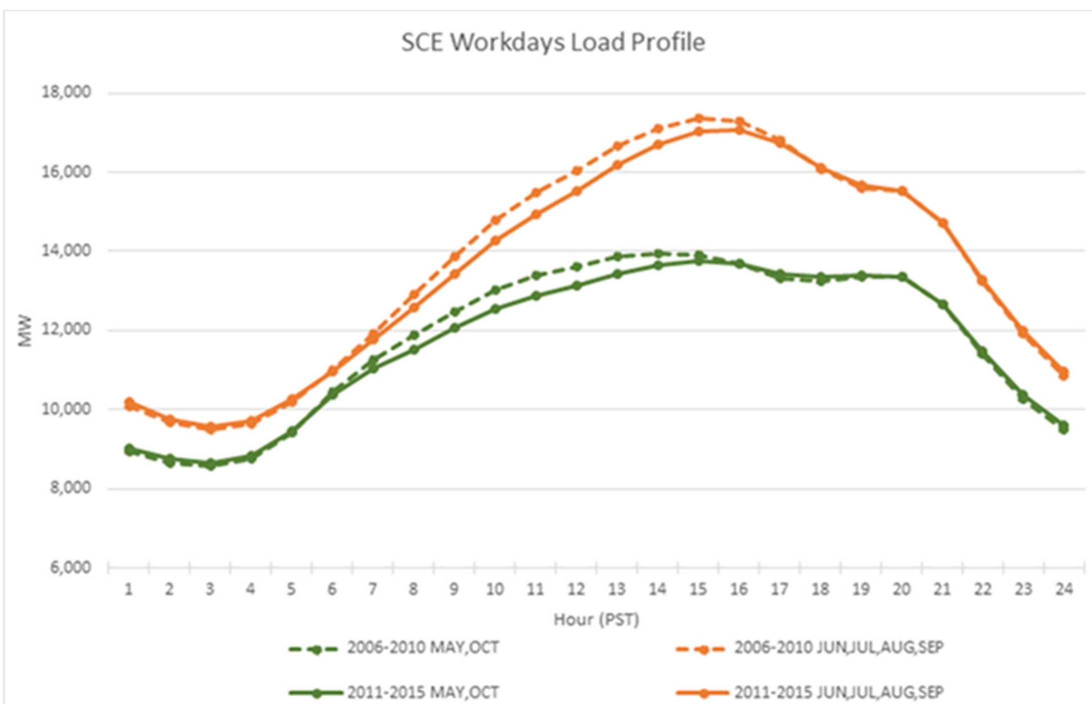
[58] While SEIA's Figure 8 shows that the percentage of extremely hot days in May and June were nearly the same during the 2001-2005 and 2011-2015 periods, the number of top 100 load hours in June has generally been consistently higher than in May. Likewise, the number of high load days in October is also relatively low.

Table II-1
Distribution of 1986-2015 Annual Top 100 Hours

Year	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total
1986-1990	13	0	35	158	175	103	16	500
1991-1995	0	0	38	39	252	130	41	500
1996-2000	0	5	8	115	272	98	2	500
2001-2005	0	3	6	189	196	102	4	500
2006-2010	0	3	39	153	180	120	5	500
2011-2015	0	5	10	65	234	173	13	500
Total	**13**	**16**	**136**	**719**	**1,309**	**726**	**81**	**3,000**

Finally, SCE observes that the load profiles for May and October are quite distinct from the load profiles for June through September, both in terms of magnitude of maximum demand and shape.

Figure II-5
SCE Weekdays Historic Load Profiles, May and Oct. vs. June-Sept. (MW)



Historical and forecasted load show that most peak hours have and will continue to occur between June through September, and not in May and October. In addition, the load profile in May and October is significantly different from the profile observed between June and

September. As a result, SCE believes that SEIA's recommendation to adopt a longer, six-month summer season should be rejected, and that the existing four-month summer season should be maintained.

III.

CONCLUSION

SCE believes that this process has provided valuable information to further the refinement of the TOU updating process and has demonstrated a remarkable degree of analytical consistency and outcome, both across the various IOUs and with the CAISO. All available evidence supports the use of sufficiently forward looking net load analyses and their subsequent impact on cost as the basis upon which to determine TOU periods. SCE's filed material also demonstrated a fair degree of TOU period stability under a variety of input assumptions and looks forward to presenting an even more robust analysis as part of its September 1, 2016 RDW filing, where its full TOU period proposal will be made.

Respectfully submitted,

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