Exhibit: ____________
Witness: John D. Wilson
Date: January 11, 2021

STATE OF CALIFORNIA

BEFORE THE PUBLIC UTILITIES COMMISSION

Order Instituting Ratemaking to	**)**	
Establish Policies, Processes, and Rules	**)**	**Rulemaking 20-11-003**
to Ensure Reliable Electric Service in	**)**	
California in the Event of an Extreme	**)**	
Weather Event in 2021	**)**	

DIRECT TESTIMONY OF

JOHN D. WILSON

ON BEHALF OF

THE SMALL BUSINESS UTILITY ADVOCATE

Resource Insight, Inc.

JANUARY 11, 2021

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ATTACHMENTS

I. Identification & Qualifications

Q: Mr. Wilson, please state your name, occupation, and business address.

A: I am John D. Wilson. I am the research director of Resource Insight, Inc., 5 Water St., Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received a BA degree from Rice University in 1990, with majors in physics and history, and an MPP degree from the Harvard Kennedy School of Government with an emphasis in energy and environmental policy, and economic and analytic methods.

I was deputy director of regulatory policy at the Southern Alliance for Clean Energy for more than twelve years, where I was the senior staff member responsible for SACE's utility regulatory research and advocacy, as well as energy resource analysis. I engaged with southeastern utilities through regulatory proceedings, formal workgroups, informal consultations, and research-driven advocacy.

My work has considered, among other things, the cost-effectiveness of prospective new electric generation plants and transmission lines, retrospective review of generation-planning decisions, conservation program design, ratemaking and cost recovery for utility efficiency programs, allocation of costs of service between rate classes and jurisdictions, design of retail rates, and performance-based ratemaking for electric utilities.

My professional qualifications are further summarized in Exhibit RII-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified more than a dozen times before utility regulators in the Southeast U.S. and Nova Scotia, filed testimony in three CPUC proceedings, and appeared numerous additional times before various regulatory and legislative bodies.

II. Introduction

Q: On whose behalf are you testifying?

A: I am testifying on behalf of Small Business Utility Advocates (SBUA). SBUA's mission is to represent the utility concerns of the small business community. Promoting an electricity rate structure that facilitates the success of small commercial customers with cost effective utilities supplying clean and renewable energy is central to this mission.[1]

There are approximately 4.1 million small businesses in the state that comprise of 99.8% of all employer firms, provide 48.5% of private sector employment, account for over 214,569 net new jobs, and comprise approximately 42.1% of California's $165.6 billion in exports.[2]

Small businesses are not only vital to California's economic health and welfare but also constitute an important class of ratepayers for utility companies.

The ratepayer interests of small businesses often diverge from residential ratepayers and larger commercial customers on a variety of utility matters. It

[1] *See,* SBUA website at www.utilityadvocates.org.

[2] 2020 California Small Business Profile, U.S. Small Business Administration Office of Advocacy. *See* https://cdn.advocacy.sba.gov/wp-content/uploads/2020/06/04142955/2020-Small-Business-Economic-Profile-CA.pdf.

is vital to small businesses that rate allocation and rate treatment are fair to all energy consumers.

Q: What is the scope of your testimony?

A: I am testifying with respect to Issue 2(b), Critical Peak Pricing (CPP) and with respect to Time of Use (TOU) rate periods, which would fall under Issue 2(h), Other Opportunities to reduce peak demand and net peak demand hours in summer 2021.

Q: What issues do you address?

A: My testimony addresses limitations on the number of CPP events, increasing the impact of CPP programs and TOU rate design on demand reduction, and aligning CPP event and TOU peak periods to the system net peak.

Q: What do you recommend?

A: The Commission should:

- Eliminate minimum and maximum annual CPP event limits for all three utilities, and provide flexibility to adapt methods for triggering CPP events, without resulting in a substantial change in the expected number of annual CPP events;
- Authorize an appropriate increase in marketing, education and outreach (ME&O) budgets for CPP programs, set non-binding CPP program goals for demand reduction, and direct the IOUs to evaluate CPP program impacts in 2021 and 2022;
- Establish a statewide 5 PM – 10 PM peak period that applies to all TOU and CPP rates for all IOUs, and direct the IOUs to create the applicable rates on a revenue-neutral basis; and

- Direct all three IOUs to waive the minimum requirement for the Base Interruptible Program and enhance ME&O efforts to increase program enrollment.

I also offer several suggestions and general statements of support:

- The IOUs should consider implementation of behavioral demand response programs using increased ME&O budgets for CPP programs.
- The Commission should ensure that any authorized advertising budget for Flex Alerts is not duplicative of efforts that are better integrated with rate-based initiatives to reduce peak demand.
- Allowing CPP enrollment for customers on distributed energy resource tariffs could benefit small businesses and encourage adoption of solar and storage in a manner that reduces demand during emergency reliability events.
- The Commission, IOUs, and Community Choice Aggregators (CCAs) should take steps to provide small businesses with greater access to TOU and CPP rates in CCA service areas.
- The Commission should consider adjustment to net electric metering (NEM) rules to enhance delivery of energy to the grid during CPP events.

III. Modifications to Critical Peak Pricing (CPP) event procedures.

Q: Please summarize the proposals for changes to the IOU's CPP programs.

A: In Comments and Reply Comments on the Order Instituting Rulemaking, a number of parties discussed potential modifications to Critical Peak Pricing (CPP) programs, such as adjusting the range of CPP events that may be called or modifying the method and process for triggering CPP events. Reply comments from the IOUs indicate opposition to the proposed changes.

With respect to the number of events,

- PG&E's Peak Day Pricing tariffs allow PG&E to call between nine and 15 events per year.[3] PG&E supports removing or reducing the minimum and removing or increasing the maximum number of events allowed to ensure availability for grid management rather than using them to meet tariff requirements or withholding them due to frequency limitations.[4] PG&E also expressed the concern that increasing the number of events could lead to bill volatility.[5]
- SCE's CPP tariffs indicate that it will call exactly 12 events per year.[6] SCE opposes changes to this standard because "it may lead to customers opting out of the program due to customer fatigue" or bill volatility.[7] SCE's Reply Comments did not explain why it prefers maintain an exact number of events per year, as the California Solar & Storage Association (CALSSA) critiqued.[8]
- SDG&E's CPP tariffs allow SDG&E to call up to 18 events per year with no minimum. SDG&E expresses concern that, "The varying number of potential events called in a year and the resulting

[3] PG&E, Pro Forma Schedule B-1, Sheet 8, AL 5861-E (June 26, 2020).

[4] PG&E, Initial Comments, p. 5.

[5] PG&E, Reply Comments, p. 3.

[6] SCE, Schedule TOU-GS-1 (March 1, 2019), Sheet 12.

[7] SCE, Reply Comments, pp. 4-5.

[8] CALSSA, Initial Comments, p. 2 ("SCE should consider modifying the tariff so that SCE has more flexibility to call the number of events that grid conditions warrant").

> fluctuation in pricing causes significant bill volatility for customers who participate in the CPP rate, particularly those who are unable to shift their energy usage outside of the event hours."[9]

I do not find any argument advanced by the utilities (or any other party) that explains why there is a need for a minimum or maximum number of events per year. Rather, it makes sense that the number of events in the average year not be too large, and that bill volatility should be moderate, and only increase when there are substantial benefits provided by CPP events.

Q: Is there any reason to limit the number of CPP events in the average year, but not in each individual year?

A: In addition to the points regarding customer participation made by the utilities, an increase in the average number of CPP events could affect rate design. If the same costs are recovered over many more events, this would result in lower CPP rates and a potentially less effective price signal to participants.

Q: What are the benefits associated with CPP rates?

A: SCE presented data in its comments regarding the impact of CPP rates on load. In its Reply Comments, SCE commented that its forecasts for 2020 load impacts are minimal, approximately 8 MW. All three IOUs enroll medium and large commercial customers in their CPP programs.[10]

Analysis by the Brattle Group suggests that customers participating in a time-varying rate with a high peak-to-off-peak ratio will reduce demand by

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[9] SDG&E, Initial Comments, p. 9.

[10] In the case of PG&E, default enrollment is temporarily suspended until the new TOU rate schedules become mandatory. PG&E Advice Letter 5785-E; SCE, Initial Comments, p. 7; SDG&E, Initial Comments, p. 11.

10% or more.[11] SCE's results suggests that its CPP response is thus driven by only around 80 MW of its load, a tiny fraction of its 23 GW system load. If just 5% of SCE's load participated effectively in its CPP program, the impacts could exceed 115 MW.

The Public Advocates Office ("Cal Advocates") argues against "marketing to increase enrollment" in the CPP reasoning, "Eligible non-residential customers are by default participating in the CPP program."[12] While I agree that there should not be "marketing to increase enrollment," to increase participation, the IOUs will need to improve ME&O activities likely involving budget increases. For example, SDG&E notes that "when large CPP customers are called directly by SDG&E's account executives," load shedding impacts increase.[13] Furthermore, SDG&E believes that many small and medium businesses "are unaware of or do not understand the CPP rate."

Thus, while there are substantial *potential* benefits of California's CPP rates, the actual benefits appear to have remained minimal due to a lack of effective ME&O activities.

Q: What other concerns have been expressed with respect to changes to CPP rates?

A: Both SCE and SDG&E are engaged in billing-system overhauls that make changes to rates more difficult, as discussed below. However, it is not clear that changes to the rules regarding the number of allowed events per year would significantly impact the billing system.

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[11] Faruqui, A. et al., "Arcturus 2.0: A meta-analysis of time-varying rates for electricity," *The Electricity Journal*, 30 (2017), p. 68. https://doi.org/10.1016/j.tej.2017.11.003

[12] Cal Advocates, Reply Comments, p. 5.

[13] SDG&E, Initial Comments, p. 11.

Cal Advocates asserts that program modifications, other than hours of program dispatch, "would involve considerable analysis of associated rate changes."[14] I disagree that changes to the rules regarding the number of allowed events per year necessarily involves analysis of associated rate changes, for two reasons.

First, the actual number of events varies from year to year for PG&E and SDG&E. As long as there is not an intent to increase or decrease the average use of these programs, there would be no immediate need to consider rate changes as a result of changing maximum and minimum number of events. In the event that CPP events are exceptionally frequent (for good cause), the Commission could direct the IOU to return the increased revenues to the participants.

Second, even if changes to the minimum and maximum number of events resulted in a long-term effect on the average number of events, rate design changes could be made at a later date. Already, the PG&E and SDG&E programs have a variable number of CPP events, so there is no exact revenue expectation for those two utilities' CPP programs.

Q: What do you recommend with respect to event limits?

A: I recommend that the Commission eliminate minimum and maximum annual CPP event limits for all three utilities, and instruct the utilities to implement practices that will result in no substantial change in the expected number of annual CPP events. The IOUs should also be given flexibility to adapt their methods for triggering CPP events, as recommended by PG&E.[15] The IOUs are clearly sensitive to adverse effects on customers, such as bill volatility, and

[14] Cal Advocates, Reply Comments, p. 4.

[15] PG&E, Initial Comments, p. 5.

the voluntary nature of these programs provides a clear path for customer feedback should CPP events be called too often.

In the event that any party offers evidence justifying minimum and maximum CPP event limits, then at a minimum SCE's program should be modified to provide a range (e.g., 8 to 16 events) – rather than an exact 12 CPP event per year requirement.

These changes should be implemented prior to June 2021. Since they do not represent billing or rate changes, but simply a change in the policy regarding the number of events, then there should be no technical obstacle to their implementation.

IV. Increasing the impact of Critical Peak Pricing (CPP) program and TOU rate design on demand reduction.

Q: What do you recommend to increase participation in CPP and other demand response programs?

A: I recommend that the Commission authorize an appropriate increase in ME&O budgets for CPP programs, and potentially consider ME&O budget increases for other demand reduction programs. PG&E and SDG&E both indicate that additional effort to encourage participation in CPP programs could be useful.[16]

Oracle suggests that behavioral demand response (BDR) programs are a proven approach to reducing peak demand that can be deployed quickly.[17] SCE and TURN support consideration of BDR program spending.[18] Oracle points

[16] PG&E, Initial Comments, p. 6; SDG&E, Initial Comments, p. 10.

[17] Oracle, Initial Comments, pp. 2-5.

[18] SCE, Reply Comments, p. 6; TURN, Reply Comments, p. 8.

out that a BDR program can emphasize the economic benefits to CPP customers of reducing load. BDR program communications should be less costly than directly calling large customers, as SDG&E has done.[19] Similarly, BDR programs could encourage non-CPP customers to shift load among TOU periods. If the Commission increases ME&O budgets, the IOUs should consider implementation of such BDR programs.

Another ME&O approach to demand reduction is creation of a new paid advertising program around the Flex Alerts program. While requests for voluntary demand reduction should not be discounted entirely, the Commission should prefer to build on existing rate design incentives and incentive-based programs. I agree that since the Flex Alerts program is intended to benefit the entire CAISO grid, moving its planning and administration to CAISO could be a useful complement to utility-specific communications, especially BDR programs. I take no specific position on Flex Alerts at this time except to encourage the Commission to ensure that it is not duplicative of efforts that are better integrated with rate-based incentives to reduce peak demand.

I also recommend that the Commission set non-binding CPP program goals, such as achieving a 5% reduction in participant load per event. The IOUs should be required to evaluate CPP program impacts in 2021 and 2022 (following each summer period) and report back to the Commission. The CPP program evaluation should measure the impact on reducing energy costs in all events, estimate demand reduction, and estimate how much the CPP program helped reduce the risk of requiring emergency reliability action, if near-shortage conditions occur during either summer 2021 or summer 2022.

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[19] SDG&E, Initial Comments, p. 11.

V. Align CPP event and TOU peak periods to the system net peak.

Q: What are the current CPP event and TOU peak periods used by the IOUs?

A: Generally, as shown in Table 1, the IOUs' CPP and TOU rate periods are aligned with a 4 PM – 9 PM period. In the case of SCE, its 4 PM – 9 PM period is split into two rates, an On-Peak rate for summer weekdays, and a Mid-Peak rate for all other days. In the case of PG&E, its CPP rates (Peak Day Pricing and SmartRate™) begin an hour later and end an hour earlier. For some tariffs, customers are still on the legacy rate.

Table 1: CPP and Peak TOU Periods, Legacy and Effective[20]

		SCE	SDG&E	PG&E
Effective or Pending[21]	CPP	4 PM – 9 PM	4 PM – 9 PM	5 PM – 8 PM
	TOU Peak	4 PM – 9 PM[22]	4 PM – 9 PM	4 PM – 9 PM
Legacy or Retired	CPP	2 PM – 6 PM	2 PM – 6 PM	2 PM – 6 PM
	TOU Peak	12 PM – 6 PM	11 AM – 6 PM Summer Weekdays 5 PM – 8 PM Winter Weekdays	12 PM – 6 PM Summer Weekdays

Sources: CPUC, D.18-08-013; CPUC, D.18-07-006; SCE Schedule TOU-GS-1; SDG&E, AL 3667-E (December 29, 2020); SDG&E, Schedule TOU-A; PG&E, AL 5861-E; PG&E, Schedules A-1, B-1 and E-6.

[20] There are some variations between commercial and residential rate periods; for simplicity, commercial rates are presented.

[21] The implementation status of the CPP and TOU Peak periods varies. All three IOUs' TOU rate periods are subject to revision in ongoing Phase 2 General Rate Case proceedings. Updates to, or confirmations of CPP rate periods for SDG&E and PG&E are also pending resolution of Advice Letters.

[22] SCE's highest rate is termed On-Peak in the summer, and Mid-Peak in the winter.

Q: Why should the Commission consider expedited alignment of CPP and TOU periods?

A: Current CPP and TOU periods end at 9 PM, before the system net peak ends. The rotating outages initiated by CAISO on August 14 extended past 9 PM.[23] The Commission should be concerned that customers were experiencing outages at the very time the rates for many customers were dropping.

The 2020 reliability events could well recur. If they do, recent modeling supports the likelihood that they will continue to occur into the late evening. A SERVM modeling study of 2030 summer peak day dispatch identified loss-of-load exposure from 7 PM – 10 PM, even though the system met the planning reserve margin.[24]

Properly selected CPP event hours, in particular, would be a low-cost source of demand reduction during emergency reliability periods; properly selected TOU peak periods will also tend to shift some load out of the high-risk hours. These rate-design reforms should be prioritized before more costly measures, even if the total demand reduction that the utilities forecast is modest, and regardless of whether the IOUs can reliably adjust the load forecast to reflect customer response.

Q: What CPP and TOU peak periods would be optimal?

A: CPP and TOU peak periods should be aligned with the highest-cost hours, reflecting generation energy, generation capacity, and T&D costs. In particular, the IOUs determine marginal generation capacity costs (MGCC)

[23] CAISO, *Preliminary Root Cause Analysis, Mid-August 2020 Heat Storm* (October 6, 2020), p. 3.

[24] E3, *SERVM Dispatch Data Study*, presented to IRP Modeling Advisory Group webinar (December 9, 2020), p. 51.

using loss-of-load expectation data in Phase 2 General Rate Cases (GRC). These data, in turn, are considered with marginal distribution capacity costs (MDCC) to determine the peak periods. From a capacity and reliability point of view, a 5 PM – 10 PM peak period is supported by evidence in all three IOU Phase 2 GRCs.[25]

In the PG&E Phase 2 GRC, PG&E's Time-of-Use Period Assessment and Analysis (Attachment RII-2) found that the highest Goodness of Separation (GOS) metric was for the 5 PM – 10 PM peak period, considering total marginal costs.[26] In that proceeding, SBUA's testimony (Attachment RII-3) includes a recommendation to shift peak hours to the 5 PM – 10 PM peak period.[27] Recognizing PG&E's concern about customer confusion, the SBUA testimony recommended that the Commission provide PG&E with discretion regarding when PG&E might move forward with the change. Considering the increased urgency indicated by the Commission in this proceeding to identify actions that would reduce peak and net peak loads, I now recommend that the Commission direct PG&E to act on this as quickly as possible.

In the SCE Phase 2 GRC, SCE's TOU Period Study (Attachment RII-4) includes a regression analysis on summer marginal costs. The regression analysis shows that costs are highest from 5 PM – 10 PM.[28] In the winter, when SCE uses a Mid-Peak rate, SCE's marginal costs show a smaller, earlier peak.

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[25] MGCCs and total marginal costs indicate very similar peak periods.

[26] The GOS for the 5 PM – 10 PM summer peak period is 80.9% compared to a GOS of 69.9% for 4 PM – 9 PM summer peak period (Table 11-5), an improvement of 11%. The corresponding improvement was 16.6% for marginal generation costs only (Table 11-2). Attachment RII-2 (PG&E Direct Testimony, A.19-11-019, Exhibit 2, Chapter 11, pp. 15-18).

[27] Attachment RII-3 (SBUA Direct Testimony, A.19-11-019, pp. 38-39).

[28] Attachment RII-4 (SCE Direct Testimony, A.20-10-012, Exhibit SCE-02, p. D-7).

SCE's TOU Period Study did not evaluate a 5 PM – 10 PM TOU peak period; the only alternatives SCE considered were 4 PM – 9 PM and 5 PM – 8 PM.

In the SDG&E Phase 2 GRC, SDG&E recommended continuing the TOU periods adopted in Decision 17-08-030, based on a record that is now at least four years out of date. Based on SDG&E's peak load and locational marginal prices, SBUA's testimony (Attachment RII-5) demonstrated that SDG&E's peak period should be shifted to 5 PM – 10 PM.[29]

Thus, evidence in all three IOUs' Phase 2 General Rate Cases demonstrates that maintaining existing CPP and TOU periods, as proposed by the IOUs, does not provide optimal price signals to customers to reduce power during potential emergency reliability periods.[30]

Q: Is it reasonable for the Commission to act outside the Phase 2 General Rate Cases to adjust CPP and TOU peak periods?

A: Yes. A Proposed Decision in this proceeding states an intent "to ensure we have taken all feasible short-term actions to avoid reliability events in the

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[29] Attachment RII-5 (SBUA Direct Testimony, A.19-03-002, pp. 17, 25). Mr. Chernick's LMP analysis also found that it would be reasonable to also have a winter peak period of 5 AM – 8 AM and potentially extending the summer peak period to 3 PM – 11 PM. For purposes of addressing statewide emergency reliability concerns, it does not appear to be necessary to adopt these longer TOU periods.

[30] The CPP periods are generally not discussed in the Phase 2 GRCs. As noted above, PG&E and SDG&E have filed advice letters regarding CPP rate periods, and would align them with TOU peak periods.

I am not recommending that peak TOU and CPP periods be uniform as a matter of general policy. The current evidence from the individual IOUs is supportive of uniform peak periods, especially given the near-term systemwide impacts of emergency reliability events. Similar uniformity in off-peak TOU periods for the IOUs is not relevant to emergency reliability events, nor is it likely to be warranted, as the time patterns of distribution (and perhaps generation) costs likely vary among the IOUs and justify differences in off-peak TOU periods.

coming summer."[31] While this is not yet final, if the Commission finalizes the direction to the IOUs to immediately pursue contracts for incremental capacity, it would indicate that the Commission is willing to advance actions that might otherwise entail more extensive review of evidence and alternatives.

With respect to measures to reduce demand to avoid future outages, adjusting CPP and TOU peak periods, along with enhanced ME&O activities, could significantly increase reliability. While achieving demand reduction will depend on the effectiveness of utility implementation, leaving these matters to the Phase 2 GRCs will defer the potential benefits of adjusted CPP and TOU peak periods to summer of 2022 at the earliest.

If the Commission is convinced that optimal alignment of CPP and TOU peak periods can have a significant influence on demand, and that it is feasible to implement these changes by summer 2021,[32] then it is both reasonable and urgent to take action in this proceeding.

Q: Do the utilities agree that it is urgent to change CPP and TOU peak periods to improve reliability and reduce costs?

A: No. The IOUs have expressed concern about the potential for customer confusion as well as the level of effort required to make changes. The IOUs have expressed a preference to maintain their current plans through approximately 2026, after conclusion of the next Phase 2 General Rate Case.

Changing CPP and TOU periods, and expediting already-planned changes, will indeed require significant effort. The utilities will need to update rates, file them for review, and implement them in their billing systems.

[31] Proposed Decision of ALJ Stevens (January 8, 2021), R.20-11-003, p. 9.

[32] Alternatively, that it is necessary to take action immediately in order to implement these changes by summer 2022.

Customer ME&O programs will need to be updated, potentially with extra effort to address customer confusion.

While the effort to change CPP and TOU periods should not be undertaken without justification, such efforts could be less impactful than the cost of otherwise-unnecessary investment in supply side resources or additional emergency reliability events. Maintaining the current TOU peak periods until 2026 or beyond in the interest of avoiding customer confusion leaves low-hanging fruit unutilized. Small businesses and other customers should not have to pay for additional expensive supply and demand resources because the utilities are charging customers off-peak power rates during the late evening hours, that represent much of the reliability risk.

Q: What do you recommend?

A: Given the emergency need to increase system reliability, the Commission should establish a statewide 5 PM – 10 PM peak period that applies to all TOU and CPP rates for all IOUs.[33]

I recommend that IOUs create the applicable peak period rates on a revenue neutral basis, applying the class or rate-specific revenue requirement

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[33] In the case of SCE, only the summer On-Peak period should be updated to 5 PM – 10 PM for emergency reliability purposes, based on the evidence of smaller winter marginal costs. Since the emergency reliability concerns are primarily in the summer months, it would also be reasonable to update only the summer TOU peak periods for PG&E and SDG&E. Nonetheless, uniform year-round TOU peak periods would be easier for customers to adopt and, as discussed above, evidence in the PG&E and SDG&E GRCs supports the same TOU peak periods in the winter months.

consistent with the current rate design, but adjusting the period rates to recover the same period-specific revenue requirement.[34]

Q: What are the potential obstacles to immediately changing CPP and peak TOU hours?

A: Two of the IOUs are implementing customer service information technology projects that may constrain immediate changes. SDG&E explains that due to implementation of its new Customer Information System, it has imposed a freeze and stabilization period that precludes it from committing to any structural rate changes before early 2022.[35] SCE states that its "[Customer Service Re-Platform (CSRP)] is expected to be implemented in Q2 2021 with project stabilization by Q4 2021."[36] SDG&E states that it is already in its stabilization period, while SCE does not indicate whether changes can be implemented before or during Q2 2021.[37]

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[34] Recognizing the concern about customer confusion, the SBUA testimony in PG&E's GRC recommended that the Commission allow PG&E discretion regarding the timing of moving forward with the pending change in time periods. Considering the increased urgency indicated by the Commission in this proceeding to identify actions that would reduce peak and net peak loads, I now recommend that the Commission direct PG&E to act on this as quickly as possible.

In the process, it may be efficient for the IOUs to optimize the timing of other periods (e.g., non-summer and weekend periods, super-off-peak periods), so long as that does not delay implementation of better timing for hours with high reliability risk.

[35] SDG&E, Reply Comments, p. 11-12.

[36] SCE, Initial Comments, p. 5.

[37] SCE has stated states that it "currently takes SCE approximately five weeks to conduct the necessary testing and system updates in order to implement a rate change." SCE, A.19-06-002, Exhibit SCE-6 (November 8, 2019), p. 3, lines 11-12. This suggests that a decision issued in February could be implemented in 2021.

Notwithstanding these objections, the Commission should push the IOUs to find some way to implement changes to TOU and CPP periods, given the potential importance of keeping customers' lights on next summer. Even if it turns out that some IOUs are paralyzed in their ability to implement rate design changes, it would still be useful to optimize the CPP and TOU peak periods for the other utility or utilities.

Q: What response to you have to other concerns have been raised regarding CPP peak periods?

A: TURN stated,

> The incremental value of CPP should be considered in light of changes to the timing of the peak TOU period for large customers, to ascertain whether the CPP will result in less actual demand response and significant "free ridership" from commercial customers whose load already decreases after close of business at 5 PM.[38]

With respect to the concern about "free ridership," customers who avoid contribution to high-risk periods are not free riders and should not be charged to costs they do not impose. That is equally true for customers who naturally do not contribute much to load in those periods (such as many schools) and customer who activity curtail or shift load out of the critical hours. As long as the TOU and CPP rate designs are reasonably cost-based, TURN's concern with free ridership is misplaced.

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[38] TURN, Reply Comments, p. 9.

VI. Further opportunities to engage small business customers.

Q: What other proposals would more effectively engage small business customers in reducing load during emergency reliability events?

A: I reviewed the proposals offered in comments on the OIR. In addition to Oracle's BDR program proposal, discussed above, four of these are likely to engage small business customers. First, CALSSA and the Joint DR Parties suggest allowing CPP enrollment for customers on certain SCE and PG&E distributed energy resource tariffs.[39] This could benefit small businesses and encourage adoption of solar and storage in a manner that reduces demand during emergency reliability periods.[40]

Second, SDG&E suggests waiving the 100 kW minimum requirement for the Base Interruptible Program, opening it to all non-residential customers.[41] SBUA supports this proposal as there may be small businesses that would benefit from participation and the opportunity to economically respond to

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[39] CALSSA, Initial Comments, p. 2; Joint DR Parties, Initial Comments, pp. 6-7.

[40] Senate Bill 1339 (Stern, 2018) directs the Commission to facilitate commercialization of microgrids. In D.20-06-017, the Commission recognized that the NEM tariff limit on storage charging was a barrier to maximizing the use of energy storage systems for resiliency during announced PSPS events. The Commission directed the utilities to modernize the NEM tariff and allow utilities to "allow energy storage systems to import from – but not export to – the grid upon receiving advanced notification by the utility of an upcoming PSPS event." (D. 20-06-017, pp. 38-39.) Energy storage systems interconnected with NEM resources remain blocked from exporting to the grid, and may not import from the grid in order to prepare for a potential emergency reliability event. These limitations restrict the commercialization of microgrids by limiting their effectiveness in meeting resiliency needs. While revising the NEM tariff is beyond the scope of this proceeding, the Commission may wish to indicate its interest in providing more flexibility related to microgrids interconnected with NEM resources, which could be considered in the NEM successor tariff proceeding (A. 20-08-020).

[41] SDG&E, Initial Comments, p. 29.

reliability events. I recommend that the Commission direct all three IOUs to waive the minimum requirement for the Base Interruptible Program and enhance their ME&O efforts to increase program enrollment.[42]

Third, as Utility Consumers' Action Network (UCAN), Silicon Valley Clean Energy Authority, and CalCCA have discussed, the CCAs perceive operational barriers to CCAs that wish to take full advantage of real-time pricing and CPP/TOU rates. CCAs describe marginal costs that differ from those of the IOUs face obstacles, and feasibility issues with the time-varying collection of PCIA charges.[43] I support any steps that can result in small business customers of CCAs having access to more effective rate options.

Resolving the operational barriers to full deployment of CPP and TOU rates by CCAs may require actions that extend beyond June 2021. The Commission should direct the IOUs to undertake those actions as soon as possible. So far, no party has identified any objection to addressing those barriers. Deferral of action to a future decision would be against the interests of identifying low-cost measures to promote reliability.

Fourth, CALSSA suggests allowing customers with storage systems to receive credits at the CPP rate for exports delivered to the grid during CPP events, and the Joint DR Parties suggest allowing CPP export compensation for SCE and SDG&E customers.[44] Considering that these issues are closely related to the NEM successor proceeding (R.20-08-020), the Commission could either adopt them on a temporary basis, for the summers of 2021 and

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[42] SCE's minimum monthly demand requirement is 200 kW.

[43] UCAN, Initial Comments, p. 2; Silicon Valley Clean Energy Authority, Reply Comments on Proposed Decision, R.17-06-026 (March 23, 2020); CalCCA, Reply Comments, p. 4.

[44] Joint DR Parties, Initial Comments, p. 6.

2022, or expedite their resolution in the NEM successor proceeding. A CPP-NEM rate that applies to behind-the-meter renewable and storage resources could be attractive to small business participation.

Changes to CPP and NEM rates may be difficult to approve and implement by June 2021, but the potential low per-kW cost of these proposals merits expedited action. Changes implemented in 2021 are likely to have an even higher uptake and benefit in 2022.

Q: Does this conclude your testimony?

A: Yes.

Attachment RII-1
Qualifications of John D. Wilson

Exhibit JDW-1

JOHN D. WILSON

Resource Insight, Inc.
5 Water Street
Arlington, Massachusetts 02476

SUMMARY OF PROFESSIONAL EXPERIENCE

2019–Present **Research Director, Resource Insight, Inc.** Provides research, technical assistance, and expert testimony on electric- and gas-utility planning, economics, and regulation. Reviews electric-utility rate design. Designs and evaluates conservation programs for electric utilities, including conservation cost recovery mechanisms and performance incentives. Evaluates performance of renewable resources and designs performance evaluation systems for procurement. Designs and assesses resource planning and procurement strategies for regulated and competitive markets.

2007-19 **Deputy Director for Regulatory Policy, Southern Alliance for Clean Energy.** Managed regulatory policy, including supervision of experts in areas of energy efficiency, renewable energy, and market data. Provided expert witness testimony on topics of resource planning, renewable energy, energy efficiency to utility regulators. Directed litigation activities, including support of expert witnesses in the areas of rate design, resource planning, renewable energy, energy efficiency, and resource procurement. Conducted supporting research and policy development. Represented SACE on numerous legislative, utility, and private committees across a wide range of climate and energy related topics.

2001–06 **Executive Director, Galveston-Houston Association for Smog Prevention.** Directed advocacy and regulatory policy related to air pollution reduction, including ozone, air toxics, and other related pollutants in the industrial, utility, and transportation sectors. Served on the Regional Air Quality Planning Committee, Transportation Policy Technical Advisory Committee, and Steering Committee of the TCEQ Interim Science Committee.

2000–01 **Senior Associate, The Goodman Corporation.** Provided transportation and urban planning consultant services to cities and business districts across Texas.

1997–99 **Senior Legislative Analyst and Technology Projects Coordinator, Office of Program Policy Analysis and Government Accountability, Florida Legislature.** Author or team member for reports on water supply policy, environmental permitting, community development corporations, school district financial management and other issues – most recommendations implemented by the 1998 and 1999 Florida Legislatures. Edited statewide government accountability newsletter and coordinated online and internal technical projects.

1997 **Environmental Management Consultant, Florida State University.** Project staff for Florida Assessment of Coastal Trends.

1992-96 **Research Associate, Center for Global Studies, Houston Advanced Research Center.** Coordinated and led research for projects assessing environmental and resource issues in the Rio Grande / Rio Bravo river basin and across the Greater Houston region. Coordinated task force and edited book on climate change in Texas.

EDUCATION

BA, Physics (with honors) and history, Rice University, 1990.

MPP, John F. Kennedy School of Government, Harvard University, 1992. Concentration areas: Environment, negotiation, economic and analytic methods.

PUBLICATIONS

"Urban Areas," with Judith Clarkson and Wolfgang Roeseler, in Gerald R. North, Jurgen Schmandt and Judith Clarkson, *The Impact of Global Warming on Texas: A Report of the Task Force on Climate Change in Texas*, 1995.

"Quality of Life and Comparative Risk in Houston," with Janet E. Kohlhase and Sabrina Strawn, *Urban Ecosystems*, Vol. 3, Issue 2, July 1999.

"Seeking Consistency in Performance Incentives for Utility Energy Efficiency Programs," with Tom Franks and J. Richard Hornby, *2010 American Council for an Energy-Efficient Economy Summer Study on Energy Efficiency in Buildings*, August 2010.

"Monopsony Behavior in the Power Generation Market," with Mike O'Boyle and Ron Lehr, *Electricity Journal*, August-September 2020.

REPORTS

"Policy Options: Responding to Climate Change in Texas," Houston Advanced Research Center, US EPA and Texas Water Commission, October 1993.

Houston Environmental Foresight Science Panel, *Houston Environment 1995*, Houston Advanced Research Center, 1996.

Houston Environmental Foresight Committee, *Seeking Environmental Improvement*, Houston Advanced Research Center, January 1996.

Florida Coastal Management Program, *Florida Assessment of Coastal Trends*, June 1997.

Office of Program Policy Analysis and Government Accountability, *Best Financial Management Practices for Florida School Districts*, Report No. 97-08, October 1997.

Office of Program Policy Analysis and Government Accountability, *Review of the Community Development Corporation Support and Assistance Program*, Report No. 97-45, February 1998.

Office of Program Policy Analysis and Government Accountability, *Review of the Expedited Permitting Process Coordinated by the Governor's Office of Tourism, Trade, and Economic Development,* Report No. 98-17, October 1998.

Office of Program Policy Analysis and Government Accountability, *Florida Water Policy: Discouraging Competing Applications for Water Permits; Encouraging Cost-Effective Water Development,* Report No. 99-06, August 1999.

"Smoke in the Water: Air Pollution Hidden in the Water Vapor from Cooling Towers – Agencies Fail to Enforce Against Polluters," Galveston Houston Association for Smog Prevention, February 2004.

"Reducing Air Pollution from Houston-Area School Buses," Galveston Houston Association for Smog Prevention, March 2004.

"Who's Counting: The Systematic Underreporting of Toxic Air Emissions," Environmental Integrity Project and Galveston Houston Association for Smog Prevention, June 2004.

"Mercury in Galveston and Houston Fish: Contamination by Neurotoxin Places Children at Risk," Galveston Houston Association for Smog Prevention, October 2004.

"Exceeding the Limit: Industry Violations of New Rule Almost Slid Under State's Radar," Galveston Houston Association for Smog Prevention, January 2006.

"Whiners Matter! Citizen Complaints Lead to Improved Regional Air Quality Control," Galveston Houston Association for Smog Prevention, June 2006.

"Bringing Clean Energy to the Southeastern United States: Achieving the Federal Renewable Energy Standard," Southern Alliance for Clean Energy, February 2008.

"Cornerstones: Building a Secure Foundation for North Carolina's Energy Future," Southern Alliance for Clean Energy, May 2008.

"Yes We Can: Southern Solutions for a National Renewable Energy Standard," Southern Alliance for Clean Energy, February 2009.

"Green in the Grid: Renewable Electricity Opportunities in the Southeast United States," with Dennis Creech, Eliot Metzger, and Samantha Putt Del Pino, World Resources Institute Issue Briefs, April 2009.

"Local Clean Power," with Dennis Creech, Eliot Metzger, and Samantha Putt Del Pino, World Resources Institute Issue Briefs, April 2009.

"Energy Efficiency Program Impacts and Policies in the Southeast," Southern Alliance for Clean Energy, May 2009.

"Recommendations for Feed-In-Tariff Program Implementation In The Southeast Region To Accelerate Renewable Energy Development," Southern Alliance for Clean Energy, March 2011.

"Renewable Energy Standard Offer: A Tennessee Valley Authority Case Study," Southern Alliance for Clean Energy, November 2012.

"Increased Levels of Renewable Energy Will Be Compatible with Reliable Electric Service in the Southeast," Southern Alliance for Clean Energy, November 2014.

"Cleaner Energy for Southern Company: Finding a Low Cost Path to Clean Power Plan Compliance," Southern Alliance for Clean Energy, July 2015.

"Analysis of Solar Capacity Equivalent Values for Duke Energy Carolinas and Duke Energy Progress Systems," prepared for and filed by Southern Alliance for Clean Energy, Natural Resources Defense Council, and Sierra Club in North Carolina NCUC Docket No. E-100, Sub 147, February 17, 2017.

"Seasonal Electric Demand in the Southeastern United States," Southern Alliance for Clean Energy, March 2017.

"Analysis of Solar Capacity Equivalent Values for the South Carolina Electric and Gas System," Southern Alliance for Clean Energy, March 2017.

"Solar in the Southeast, 2017 Annual Report," with Bryan Jacob, Southern Alliance for Clean Energy, February 2018.

"Energy Efficiency in the Southeast, 2018 Annual Report," with Forest Bradley-Wright, Southern Alliance for Clean Energy, December 2018.

"Solar in the Southeast, 2018 Annual Report," with Bryan Jacob, Southern Alliance for Clean Energy, April 2018.

"Tracking Decarbonization in the Southeast, 2019 Generation and CO_2 Emissions Report," with Heather Pohnan and Maggie Shober, Southern Alliance for Clean Energy, August 2019.

"Seasonal Electric Demand in the Southeastern United States," with Maggie Shober, Southern Alliance for Clean Energy, April 2020.

"Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement," with Mike O'Boyle, Ron Lehr, and Mark Detsky, Energy Innovation Policy & Technology LLC and Southern Alliance for Clean Energy, April 2020.

PRESENTATIONS

"Clean Energy Solutions for Western North Carolina," presentation to Progress Energy Carolinas WNC Community Energy Advisory Council, February 7, 2008.

"Energy Efficiency: Regulating Cost-Effectiveness," Florida Public Service Commission undocketed workshop, April 25, 2008.

"Utility-Scale Renewable Energy," presentation on behalf of Southern Alliance for Clean Energy to the Board of the Tennessee Valley Authority, March 5, 2008.

"An Advocates Perspective on the Duke Save-a-Watt Approach," ACEEE 5th National Conference on Energy Efficiency as a Resource, September 2009.

“Building the Energy Efficiency Resource for the TVA Region,” presentation on behalf of Southern Alliance for Clean Energy to the Tennessee Valley Authority Integrated Resource Planning Stakeholder Review Group, December 10, 2009.

“Florida Energy Policy Discussion,” testimony before Energy & Utilities Policy Committee, Florida House of Representatives, January 2010.

“The Changing Face of Energy Supply in Florida (and the Southeast),” 37th Annual PURC Conference, February 2010.

“Bringing Energy Efficiency to Southerners,” Environmental and Energy Study Institute panel on “Energy Efficiency in the South,” April 10, 2010.

“Energy Efficiency: The Southeast Considers its Options,” NAESCO Southeast Regional Workshop, September 2010.

“Energy Efficiency Delivers Growth and Savings for Florida,” testimony before Energy & Utilities Subcommittee, Florida House of Representatives, February 2011.

“Rates vs. Energy Efficiency,” 2013 ACEEE National Conference on Energy Efficiency as a Resource, September 2013.

“TVA IRP Update,” TenneSEIA Annual Meeting, November 19, 2014.

“Views on TVA EE Modeling Approach,” presentation with Natalie Mims to Tennessee Valley Authority’s Evaluating Energy Efficiency in Utility Resource Planning Meeting, February 10, 2015.

“The Clean Power Plan Can Be Implemented While Maintaining Reliable Electric Service in the Southeast,” FERC Eastern Region Technical Conference on EPA’s Clean Power Plan Proposed Rule, March 11, 2015.

“Renewable Energy & Reliability,” 5th Annual Southeast Clean Power Summit, EUCI, March 2016.

“Challenges to a Southeast Carbon Market,” 5th Annual Southeast Clean Power Summit, EUCI, March 2016.

“Solar Capacity Value: Preview of Analysis to Date,” Florida Alliance for Accelerating Solar and Storage Technology Readiness (FAASSTeR) meeting, Orlando, FL, November 2017.

“Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement,” Southeast Energy and Environmental Leadership Forum, Nicholas Institute for Environmental Policy Solutions, August 2020.

EXPERT TESTIMONY

2008 **South Carolina PSC** Docket No. 2007-358-E, surrebuttal testimony on behalf of Environmental Defense, the South Carolina Coastal Conservation League, Southern Alliance for Clean Energy and the Southern Environmental Law Center. Cost recovery mechanism for energy efficiency, including shareholder incentive and lost revenue adjustment mechanism.

2009 **North Carolina NCUC** Docket No. E-7, Sub 831, direct testimony on behalf of Environmental Defense Fund, Natural Resources Defense Council, Southern Alliance for Clean Energy, and Southern Environmental Law Center. Cost recovery mechanism for energy efficiency, including shareholder incentive and lost revenue adjustment mechanism.

Florida PSC Docket Nos. 080407-EG through 080413-EG, direct testimony on behalf of Southern Alliance for Clean Energy and the Natural Resources Defense Council. Energy efficiency potential and utility program goals.

South Carolina PSC Docket No. 2009-226-E, direct testimony in general rate case on behalf of Environmental Defense, the Natural Resources Defense Council, the South Carolina Coastal Conservation League, Southern Alliance for Clean Energy and the Southern Environmental Law Center. Cost recovery mechanism for energy efficiency, including shareholder incentive and lost revenue adjustment mechanism.

2010 **North Carolina NCUC** Docket No. E-100, Sub 124, direct testimony on behalf of Environmental Defense Fund, the Sierra Club, Southern Alliance for Clean Energy, and Southern Environmental Law Center. Adequacy of consideration of energy efficiency in Duke Energy Carolinas and Progress Energy Carolinas' 2009 integrated resource plans.

Georgia PSC Docket No. 31081, direct testimony on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of energy efficiency in Georgia Power's 2010 integrated resource plan, including cost effectiveness, rate and bill impacts, and lost revenues.

Georgia PSC Docket No. 31082, direct testimony on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of energy efficiency in Georgia Power's 2010 demand side management plan, including program revisions, planning process, stakeholder engagement, and shareholder incentive mechanism.

2011 **South Carolina PSC** Docket No. 2011-09-E, allowable ex parte briefing on behalf of Southern Alliance for Clean Energy, South Carolina Coastal Conservation League, and Upstate Forever. Adequacy of South Carolina Electric & Gas's 2011 integrated resource plan, including resource mix, sensitivity analysis, alternative supply and demand side options, and load growth scenarios.

South Carolina PSC Docket Nos. 2011-08-E and 2011-10-E, allowable ex parte briefing on behalf of Southern Alliance for Clean Energy, South Carolina Coastal Conservation League, and Upstate Forever. Adequacy of Progress Energy Carolinas and Duke Energy Carolinas' 2011 integrated resource plans, including resource mix, sensitivity analysis, alternative supply and demand side options, cost escalation, uncertainty of nuclear and economic impact modeling.

2013 **Georgia PSC** Docket No. 36498, direct testimony on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of energy efficiency in Georgia Power's 2013 integrated resource plan, including cost effectiveness, rate and bill impacts, and lost revenues, economics of fuel switching and renewable resources.

South Carolina PSC Docket No. 2013-392-E, direct testimony with Hamilton Davis in Duke Energy Carolinas need certification case on behalf of the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. Need for capacity, adequacy of energy efficiency and renewable energy alternatives, and use of solar power as an energy resource.

2014 **South Carolina PSC** Docket No. 2014-246-E, direct testimony generic proceeding on behalf of the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. Methods for calculating dependable capacity credit for renewable resources and application to determination of avoided cost.

2015 **Florida PSC** Docket No. 150196-EI, direct testimony in Florida Power & Light need certification case on behalf of Southern Alliance for Clean Energy. Appropriate reserve margin and system reliability need.

2016 **Georgia PSC** Docket No. 40161, direct testimony on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of renewable energy in Georgia Power's 2016 integrated resource plan, including portfolio diversity, operational and implementation risk, analysis of project-specific costs and benefits (including location and technology considerations), and methods for calculating dependable capacity credit for renewable resources.

2019 **Georgia PSC** Docket Nos. 42310 and 42311, direct testimony with Bryan A. Jacob in Georgia Power's 2019 integrated resource plan and demand side management plan on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of renewable energy in IRP, retirement of uneconomic plants, and use of all-source procurement process. Shareholder incentive mechanism for both renewable energy and DSM plan.

2020 **Nova Scotia UARB** Matter No. M09519, direct testimony with Paul Chernick in Nova Scotia Power's application for approval of the Smart Grid Nova Scotia Project on behalf of the Nova Scotia Consumer Advocate. Cost classification, decommissioning costs, justification for software vendor selection, and suggested changes to project scope.

Nova Scotia UARB Matter No. M09499, direct testimony with Paul Chernick in Nova Scotia Power's 2020 annual capital expenditure plan on behalf of the Nova Scotia Consumer Advocate. Potential to decommission hydroelectric systems, review of annually recurring capital projects, use of project contingencies, and cost minimization practices.

Nova Scotia UARB Matter No. M09579, direct testimony with Paul Chernick in Nova Scotia Power's application for the Gaspereau Dam Safety Remedial Works on behalf of the Nova Scotia Consumer Advocate. Alternatives to proposed project, project contingency factor, estimation of archaeological costs, and replacement energy cost calculation.

Nova Scotia UARB Matter No. M09609, direct testimony with Paul Chernick in Nova Scotia Power's application for the Advanced Distribution Management System Upgrade on behalf of the Nova Scotia Consumer Advocate. Need for the ADMS and integration with the Distributed Energy Resources Management System.

Nova Scotia UARB Matter No. M09707, direct testimony with Paul Chernick on Nova Scotia Power's 2020 Load Forecast on behalf of the Nova Scotia Consumer Advocate. Impacts of recession, application of end-use studies, improvements to forecast components, and impact of time-varying pricing.

California PUC Docket A.19-10-012, direct and rebuttal testimony with Paul Chernick in San Diego Gas & Electric's application for the Power Your Drive Electric Vehicle Charging Program on behalf of the Small Business Utility Advocates. Ensuring that utility-installed chargers advance California goal for electric vehicles. Budget controls. Reporting requirements. Evaluation, monitoring and verification processes. Outreach to small business customers.

California PUC Docket A.19-08-012, direct testimony in Southern California Edison's 2021 general rate case (track 2) on behalf of the Small Business Utility Advocates. Reasonableness of remedial software costs to be included in authorized revenue requirement.

Georgia PSC Docket Nos. 4822, 16573 and 19279, direct, rebuttal and surrebuttal testimony in Georgia Power Company's PURPA avoided cost review on behalf of the Georgia Large Scale Solar Association. Reviewing compliance with prior Commission orders. Application of capacity need forecast in projection of avoided capacity cost. Calculation of cost of new capacity. Proposal of standard offer contract.

Nova Scotia UARB Matter No. M09548, direct testimony on the audit of Nova Scotia Power's Fuel Adjustment Mechanism. Reasonableness of fuel contract costs. Scope of study on dispatch practices. Impact of greenhouse gas shadow pricing. Compliance issues related to resource planning.

Attachment RII-2
Excerpt from PG&E Direct Testimony,
PG&E Phase 2 GRC A.19-11-019

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 11
TIME-OF-USE PERIOD ASSESSMENT AND ANALYSIS

A. Introduction

Two California Public Utilities Commission (CPUC or Commission) decisions require Pacific Gas and Electric Company (PG&E) to provide data on marginal distribution costs (MDC) that contribute to total peak-hour marginal cost[1] and assess the appropriateness of the Time-of-Use (TOU) periods and seasons it currently uses in rates. This chapter provides the required data and assessments and presents how PG&E proposes to proceed based on its analysis.

First, Decision (D.) 17-01-006 directs PG&E and the other investor-owned utilities (IOU) to provide three types of data: (1) "marginal distribution costs that contribute to total peak-hour marginal cost;" (2) TOU information included in IOU transmission filings at the Federal Energy Regulatory Commission (FERC) or adopted in FERC transmission rate proceedings; and (3) information on the status of Distributed Energy Resource (DER) valuation methodologies being developed in Rulemaking (R.) 14-08-013 and 14-10-003 or successor proceedings.[2] PG&E describes the required data and information in Section B.

Second, D.18-08-013 directs PG&E to "refresh its data appearing in Chapter 12 of PG&E-9 for its next GRC Phase II Application and describe why June should or should not be included in its summer season in that Application."[3] PG&E describes the methodology and data from Chapter 12 of its 2017 General Rate Case (GRC) Phase II (Application (A.) 16-06-013), and the results from refreshing these data based on modeling proposed in this proceeding, in Section C, below.

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1 PG&E considers that only Primary distribution costs are time-differentiated. Thus, only Primary marginal distribution costs "contribute to total peak-hour marginal cost." In this chapter, MDC therefore refers to what are called Primary Marginal Distribution Capacity Costs (MDCC) in Chapter 8.

2 See Ordering Paragraph (OP) 3.

3 D.17-01-006, *Id.*

Finally, D.17-01-006 directs PG&E and the other IOUs to submit Tier 2 advice letters (AL) setting forth their proposals for determining when a change in the time pattern of electricity costs would be sufficiently large (exceeding a "Dead Band Tolerance") to allow a proposal to revise TOU periods more frequently than every two GRC cycles, along with a mechanism for implementation.[4,5] D.17-01-006 requires a base TOU period analysis to be provided in each GRC, even if the IOU does not propose a change in Base TOU periods.[6] PG&E describes its Dead Band Tolerance analysis methodology and results in Section D, below.

Because the last two directives listed above require PG&E to consider only marginal generation costs (MGC) in its evaluation of TOU periods and seasons,[7] PG&E considers both seasonal and TOU changes initially using only MGC data. However, to facilitate consideration of the contribution of MDCs to time-varying marginal costs, and seasonal and TOU definitions, PG&E also provides the same analyses using a combination of MGCs and MDCs.

The results of the analysis show that the Dead Band Tolerance range for the peak period has been exceeded based on MGCs; however, PG&E is not proposing a change in Base TOU periods at this time. This is consistent with PG&E's objective in this proceeding as described in PG&E's policy chapter, Exhibit (PG&E-1), Chapter 1, to minimize rate design changes at this time (e.g., levels of customer charges, TOU and demand charge relationships).

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4 Also, on February 16, 2017, the CPUC issued D.17-02-017, titled "Order Correcting Errors in Decision 17-01-006."

5 On March 30, 2017, PG&E submitted AL 5037-E, which described PG&E's original Dead Band Tolerance proposal, and a proposed mechanism for implementation. On November 29, 2018, the Commission issued Resolution E-4948, approving with modifications the Dead Band Tolerance proposals of PG&E and the other IOUs and directing the IOUs to modify their proposals via supplemental compliance ALs within 30 days of the effective date of the order. PG&E then issued Supplemental AL E-4948-E-A on December 28, 2018, which became effective as of January 2, 2019.

6 See D.17-01-006, Appendix 1, p. 2, Section 6.

7 For the question of whether June should or should not be included in the summer season, the "data appearing in Chapter 12 of PG&E-9" are based on MGCs, and thus PG&E's refresh of those data should also consider only MGCs. Also, the second "general principle" adopted by the Commission in D.17-01-006, states "Base TOU periods should be based on utility-specific marginal costs, rather than on a statewide load assessment. This marginal cost analysis should use MGC, consisting of marginal energy costs and marginal generation capacity costs." (D.17-01-006, p. 12.)

Minimizing rate design changes will provide a reasonable degree of stability in rates for the 2020 GRC Phase II cycle, needed due to the significant customer transitions to new rates and new, later TOU periods in all customer sectors that the CPUC has already approved and which are still being rolled out to customers during the period 2020-2022. Per D.18-05-011 and D.19-07-004, PG&E will begin transitioning eligible Residential customers in waves to the default TOU rate with a 4 p.m. to 9 p.m. peak period starting in October 2020 and finishing in or about early 2022. Per D.18-08-013 and PG&E Advice Letter 5785-E, approved April 20, 2020, PG&E will be transitioning all eligible Commercial customers to rates with a 4 p.m.- 9 p.m. peak period in March 2021, and all eligible Agricultural customers to rates with a 5 p.m.-8 p.m. peak period.[8]

Rate structure stability is needed to provide time for customers to adapt to their new TOU rate structures, avoid customer confusion that would result if TOU periods were to change soon after this ongoing rollout-out process, and increase customer understanding and acceptance of rate transitions. Note that if PG&E were to propose changes to TOU periods in this proceeding, the changes would be expected to be in place sometime in 2023, just one to two years after customers would have become subject to new TOU periods. This does not seem to allow enough time for such customers to have adapted to those TOU periods, which will be widely marketed, and PG&E believes would be too soon to force them to shift their business systems yet again to accommodate yet another change in TOU period hours.

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8 The new Commercial rates will also have a Super-Off-Peak period of 9 a.m.-2 p.m. in March through May, and Commercial and Agricultural summer / winter season definitions are changing from a six month summer / six month winter, to a four month summer / eight month winter.

B. Marginal Distribution Costs, TOU Information in FERC Filings, and Status of DER Valuation Methodologies

1. Marginal Distribution Cost in 2025

In accordance with OP 3 of D.17-01-006, PG&E forecasted Primary MDCs as of the TOU Target Year of 2025.[9] While both historical and forecast information on distribution marginal costs can be developed at a Division level, D.17-01-006 concludes that

> [g]eographically-differentiated TOU time periods within an IOU's service territory are not required or encouraged at this time.[10]

PG&E therefore developed a 2025 forecast of MDCs from available forecasts of aggregate (service territory-wide) loads, incorporating forecasts of aggregate DER levels. MDCs were calculated by multiplying the annual Primary MDCC of $47.96 per kilowatt-year set forth in Chapter 7 of this exhibit by Peak Capacity Allocation Factors, as described in Chapter 8 of this exhibit.[11] Table 11-1 presents the average MDCs[12] by TOU period, while Figure 11-1 shows average MDCs by hour ending (HE) and month.

In Figure 11-1, the current summer Peak period is outlined in red; the summer Partial-Peak period is outlined in orange; and the Super-Off-Peak (SOP) period is outlined in green. Data in Table 11-1 and Figure 11-1 show that the vast majority of MDCs occur during the summer Peak period, with lesser but still significant costs in HE 22 (i.e., the 60-minute period between 9 p.m. and 10 p.m.) in summer, the Partial Peak in September, and during the winter Peak in October. MDCs in all other month-hour combinations are less than one cent per kilowatt-hour.

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[9] In accordance with D.17-01-006 (specifically, General Principle #4), TOU periods must be evaluated using marginal costs forecasted as of at least three years after the new rates would go into effect. Assuming that a Final Decision in this Application is issued in or about mid-2021, the earliest that rates based on this Application could be implemented *using new definitions of season or TOU period* would likely be mid-2022, due to the necessary structural Information Technology programming as well as customer education that would be required to prepare customers for new seasons and/or TOU periods. This implies that the forecast year to be used in evaluating seasons and TOU periods (which PG&E refers to as the TOU Target Year) is 2025.

[10] See Appendix 1, p. 1.

[11] Details of the calculations are available in Workpapers.

[12] These data are not weighted by hourly-average load.

TABLE 11-1
AVERAGE MARGINAL PRIMARY DISTRIBUTION COSTS
BY TIME-OF-USE PERIOD AS OF 2025 (CENTS PER KWH)

Line No.	TOU Period	Marginal Distribution Cost
1	Summer Peak	8.47
2	Summer Partial-Peak	1.23
3	Summer Off-Peak	0.07
4	Winter Peak	0.61
5	Winter Off-Peak	0.04
6	Spring SOP	0.03

FIGURE 11-1
AVERAGE MARGINAL DISTRIBUTION COSTS
BY MONTH AND HOUR ENDING AS OF 2025
(CENTS PER KWH)

Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0	0	0	0	0	0	0	0.03	0.03	0.01	0.01	0.01	0.00	0.01	0.01	0.02	0.09	0.35	0.51	0.52	0.36	0.16	0.01	0.00
2	0	0	0	0	0	0	0	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.13	0.21	0.12	0.03	0.00	0.00
3	0	0	0	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.06	0.06	0.01	0.00	0.00
4	0	0	0	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0	0	0	0	0	0	0	0.00	0.01	0.05	0.07	0.09	0.10	0.11	0.11	0.10	0.20	0.36	0.26	0.16	0.28	0.18	0.02	0.00
6	0	0	0	0	0	0	0	0.00	0.01	0.03	0.04	0.06	0.04	0.07	0.22	0.51	1.59	6.16	12.01	13.03	9.50	5.03	0.86	0.02
7	0	0	0	0	0	0	0	0.00	0.01	0.04	0.05	0.04	0.03	0.02	0.02	0.04	0.16	1.71	10.00	11.98	7.21	2.21	0.13	0.00
8	0	0	0	0	0	0	0	0.00	0.07	0.16	0.16	0.16	0.15	0.13	0.14	0.35	2.07	7.46	13.93	12.82	8.55	2.98	0.37	0.01
9	0.006	0	0	0	0	0	0	0.08	0.26	0.38	0.40	0.45	0.52	0.64	1.02	2.24	6.11	12.22	13.23	11.72	8.05	2.97	0.58	0.02
10	0	0	0	0	0	0	0	0.23	0.25	0.19	0.25	0.31	0.37	0.43	0.50	0.91	2.71	4.66	5.04	4.89	2.28	0.49	0.04	0.00
11	0	0	0	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.08	0.08	0.04	0.01	0.00	0.00
12	0	0	0	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.23	0.26	0.19	0.08	0.00	0.00

2. TOU Information Contained in FERC Transmission Filings

In D.17-01-006, the Commission required that the IOUs report on TOU information included in IOU transmission filings at the FERC or adopted in FERC transmission rate proceedings. PG&E has not included TOU information in any FERC filings to date, nor has the FERC adopted any transmission rates for PG&E that include TOU information.

3. Distribution Resource Plan and Integrated Distributed Energy Resources Valuation Methodologies

In D.17-01-006, the Commission required that the IOUs include information on the status of the Distribution Resource Plan (DRP) and Integrated Distributed Energy Resources (IDER) valuation methodologies and relationship of these methodologies to the data presented by the IOU.[13] In this section, PG&E provides an update from these proceedings, which initially proceeded on parallel paths but are now moving closer to a universal cost-effectiveness framework.

In October 2014, the Commission opened IDER R.14-10-003 to consider the development and adoption of a regulatory framework to provide policy consistency for the direction and review of demand-side resource programs (the "IDER Proceeding"). One of the cornerstones of the IDER Proceeding is the development of technology-neutral cost-effectiveness methods and protocols including standardization of the Avoided Cost Calculator (ACC) across DER proceedings and development of a Societal Cost Test (SCT) for determining cost-effectiveness of demand-side resources.

On September 28, 2017, the Commission issued D.17-09-026 (the "Decision") adopting the Locational Net Benefit Analysis (LNBA) methodology from the Track 1 decision of the DRP proceeding (R.14-08-013). That Track 1 decision had found the LNBA methodology developed by the LNBA working group to be useful for calculating the value of avoided costs provided by DERs for specific distribution deferral projects that the IOUs were considering for competitive solicitation. In addition, PG&E and the other large IOUs were directed to use LNBA for the Public Tool and Heat Map and the Distribution Investment Deferral Framework that was being considered at the time (and was ultimately adopted in D.18-02-004). The September 2017 Decision further directed that the LNBA tool incorporate additional value streams, including avoided distribution capacity costs beyond the ten-year planning cycle, asset life extension avoided costs, and contributions from smart inverters. The Decision also requires the LNBA to consider DER integration costs to inform other Commission proceedings (e.g., net energy metering).

Concurrent with the development of the two consensus use cases adopted in D.17-09-026, in a Ruling dated June 7, 2017, the Assigned Commissioner directed continued discussions on long-term refinements

13 See D.17-01-006, p. 28; see also OP 3.

pertaining to LNBA, including the appropriate avoided local generation capacity costs and avoided local transmission costs. Working group meetings continued until December 2017, and the IOUs filed a final working group report on long-term LNBA refinements on January 9, 2018.

The scope of the DRP proceeding (R.14-08-013), in accordance with Public Utilities Code (Pub. Util. Code) Section 769, includes determining how to calculate the value of avoided transmission and distribution (T&D) costs for DERs procured through Commission mandated programs, such as energy efficiency or net energy metering, including

> [e]valuat[ing] locational benefits and costs of distributed resources located on the distribution system. This evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provide to the electrical grid or costs to ratepayers of the electrical corporation."[14]

To resolve this issue, Administrative Law Judge (ALJ) Mason issued a Ruling on June 5, 2019, seeking comments on an Energy Division (ED) staff white paper proposing a new methodology for calculating the value that results from DERs deferring T&D investments. That Ruling and staff white paper have begun a stakeholder process for updating the avoided T&D cost methodology for use in the ACC. On June 21, 2019, the parties, including the IOUs, Solar Energy Industries Association, and The Utility Reform Network, filed opening comments. On July 18, 2019, ED staff hosted a workshop to review and gather input from parties on the staff proposal and allow parties to present methodologies for calculating a value that results from DERs deferring transmission investments. Reply comments were filed August 23, 2019. ED staff shared a proposed schedule to resolve this matter at the July 18th workshop, with the next step being to have the Energy and Environmental Economics, Inc. consulting group model the avoided T&D methodology by October 2019, and then provide these modeling results via an ALJ or Commissioner Ruling in late-October 2019. Further developments regarding T&D costs and DER valuation occurred in the IDER (ACC Update) proceeding, described below.

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14 Pub. Util. Code 769(b)(1).

In D.19-05-019, the CPUC adopted new cost-effectiveness policies for DERs in the electric sector to align the IDER, DRP and Integrated Resource Plan (IRP) proceedings and move closer to a universal cost-effectiveness framework in the future. D.19-05-019 established the Total Resource Cost as the primary test of cost-effectiveness for all DERs, with consideration of the Program Administrator Cost and Ratepayer Impact Measure for any DER regulatory activities. Additionally, three elements of the SCT are to be tested in the IRP for informational purposes only through 2020.

In D.19-05-019, the CPUC also adopted a regulatory process for changes to the ACC with minor updates approved through a Resolution process in odd years and major updates requiring a formal process to be initiated in odd years and completed in even years. The ACC was originally developed in 2004, and through periodic updates has continued to serve as a relevant and useful tool for computing utility avoided costs. The values produced in the tool (such as utility costs for energy, generation capacity, T&D investments, and environmental compliance) are used in demand-side proceedings to determine the cost-effectiveness of DER such as energy efficiency, demand response, and distributed generation.[15] The ACC or its underlying methodology has also been used in other contexts, such as evaluations of the impacts of behind-the-meter energy storage[16] and default TOU rates.[17]

The Commission has recently provided direction for the 2020 major updates to the ACC model in D.20-04-010 (the IDER Decision), which determined that unspecified distribution marginal costs in the ACC should use a system average approach (called “Method 1” in the staff white paper), and that unspecified transmission costs in the ACC should use values from utility GRCs. In particular, unspecified transmission marginal costs

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15 See D.16-06-007 at OP 1.h.

16 See 2017 Self Generation Incentive Program Advanced Energy Storage Impact Evaluation, September 7, 2018, available at: https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Demand_Side_Management/Customer_Gen_and_Storage/2017_SGIP_AES_Impact_Evaluation.pdf.

17 See Attachment 1 of Supplemental Testimony on Calculation of Cost Estimates and Greenhouse Gas Reductions, A.17-12-011, September 26, 2018.

(i.e., transmission costs not associated with specific, identified transmission upgrades) for Southern California Edison and San Diego Gas & Electric should be developed by staff based on PG&E's transmission marginal cost methodology.[18]

In addition, the IDER Decision formally links up the ACC with the IRP proceeding, directing that avoided energy and ancillary services costs shall be based on costs from the Strategic Energy and Risk Valuation Model (SERVM) production cost model, while avoided generation capacity costs for the ACC shall be determined by the net cost of new entry of a storage battery based on the SERVM-developed energy and ancillary services costs. Details of many of the methodologies spelled out in the IDER Decision were discussed in workshops on May 6-8, 2020, following issuance of the draft Resolution E-5077 that adopts the 2020 ACC on May 1. PG&E notes that while the IDER Decision is not binding on PG&E's GRC Phase II proceeding, its direction regarding marginal transmission, energy and capacity costs generally support PG&E's filing, in that the IDER Decision explicitly references PG&E's methodology for unspecified transmission marginal costs, while specifying essentially the same capacity cost methodology as PG&E describes in Chapter 2. The only significant differences are that the IDER Decision specifies the use of SERVM to calculate energy and ancillary service prices rather than a statistically-derived model,[19] and that PG&E uses short-run capacity costs from an existing combined cycle unit when those are higher than the long-run capacity costs of a new battery and in years when new capacity is not needed for reliability.

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18 D.20-04-10, p. 3.

19 On the other hand, the associated Staff Proposal notes that energy prices from production simulation models are too "flat," and proposes adjusting high and low energy prices to better match historical data. This is similar to the PG&E Marginal Energy Cost (MEC) model including the spread parameter in its objective function, as described in section B.1.d of Chapter 2.

C. Revisiting the Summer Period: Should June Still Be Designated a Summer Month?

In Chapter 12 of the Marginal Costs Volume, Exhibit (PG&E-9) of PG&E's 2017 GRC Phase II Testimony, PG&E determined that the period June through September should be chosen as the summer months, based on the number of hours with high MGCs ("high cost hours") occurring in each month. In that determination, PG&E considered both the top 100 hours and the top 250 hours of the year as high cost hours and used a forecast year of 2020. This summer period definition was adopted by the CPUC in D.18-08-013.[20] To refresh the data and analysis developed for the 2017 GRC, PG&E uses the same designation of top 100 and top 250 hours based on forecasted MGCs, but, in accordance with the TOU Order Instituting Rulemaking decision, PG&E uses the forecast year of 2025 required to be considered in the TOU period analysis below.

To provide a basis for comparison with results from the 2017 GRC Phase II, in Figure 11-2, PG&E (1) provides a reproduction of the previous case's Table 12-2 from Exhibit (PG&E-9) (which was based on a 2020 forecast); and (2) presents results using updated MGCs for forecast years of 2020 and 2025. The current summer period (June through September) is highlighted in green background, while the forecasts based on the updated model for a forecast year of 2025 are highlighted in bold, and the period with the highest number of high-cost hours based on the updated MGCs is outlined in orange.

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[20] See D.18-08-013, p. 32.

FIGURE 11-2
DISTRIBUTION OF TOP GENERATION MARGINAL COST HOURS ACROSS CALENDAR MONTHS FROM 2017 AND 2020 GRC FORECASTS

Percent Count of High Cost Hours (Energy + Capacity)							
		Top 250 Hours			Top 100 Hours		
Row	Month	2017 GRC (Year 2020)	2020 GRC (Year 2020)	**2020 GRC (Year 2025)**	2017 GRC (Year 2020)	2020 GRC (Year 2020)	**2020 GRC (Year 2025)**
1	Jan	1	0	**0**	0	0	**0**
2	Feb	0	0	**0**	0	0	**0**
3	Mar	0	0	**0**	0	0	**0**
4	Apr	0	0	**0**	0	0	**0**
5	May	0	0	**0**	0	0	**0**
6	Jun	2	1	**0**	1	0	**0**
7	Jul	39	21	**10**	65	16	**6**
8	Aug	24	30	**23**	28	40	**32**
9	Sep	10	24	**27**	5	35	**40**
10	Oct	6	17	**19**	0	7	**15**
11	Nov	8	7	**10**	0	2	**6**
12	Dec	10	0	**10**	1	0	**1**

PG&E notes that the updated forecasts for both 2020 and 2025 show one fewer high-cost hour in June, and moderately more in October than those identified for 2020 in PG&E's 2017 GRC. All forecasts also show a modest number of high-cost hours in early winter (November-December), and virtually none in late winter and spring (January-May).

In the absence of customer considerations, the data displayed in Figure 11-2, especially the figures for the months outlined in orange, suggest that June should *not* be treated as a summer month for rates that apply in the early to mid-2020s, while October *should* be treated as a summer month for such rates. However, PG&E is concerned that the rate instability of changing the definition of summer months to July-October only about two years after the summer season definition had been changed to June-September would cause customer confusion.

In addition, as described in Section A, PG&E also performed the same analysis, using the sum of MGCs and MDCs to establish Top 250 and Top 100 hour designations. The results from that analysis of combined marginal costs is presented in Figure 11-3. Because PG&E's 2017 GRC analysis did not consider MDCs directly to support the summer season definition, Figure 11-3 compares the Top Cost hours using MGCs plus MDCs only with the MGC-only results from Figure 11-2.

FIGURE 11-3
DISTRIBUTION OF TOP MARGINAL COST HOURS ACROSS CALENDAR MONTHS FROM 2020 GRC FORECASTS

Percent Count of High Cost Hours in 2025 (2020 GRC)					
		Top 250 Hours		Top 100 Hours	
Row	Month	MGC Only (Figure 11-2)	MGC Plus MDCC	MGC Only (Figure 11-2)	MGC Plus MDCC
1	Jan	**0**	**0**	**0**	**0**
2	Feb	**0**	**0**	**0**	**0**
3	Mar	**0**	**0**	**0**	**0**
4	Apr	**0**	**0**	**0**	**0**
5	May	**0**	**0**	**0**	**0**
6	Jun	**0**	**11**	**0**	**17**
7	Jul	**10**	**14**	**6**	**6**
8	Aug	**23**	**23**	**32**	**28**
9	Sep	**27**	**28**	**40**	**41**
10	Oct	**19**	**16**	**15**	**8**
11	Nov	**10**	**5**	**6**	**0**
12	Dec	**10**	**4**	**1**	**0**

The addition of MDCs to the generation marginal costs clearly shifts the forecasted distribution of top hours from July-October (outlined in orange) back to the current definition of June-September (outlined in black). PG&E believes that the primary driver of this difference is that solar generation (which peaks in June, and is only moderate in October) affects the distribution system (and thus MDCs) only one third as much as it affects the generation system (and thus MGCs).[21] Thus MDCs not only peak earlier in the day than MGCs, they also peak earlier in the year. The result is that while June is not forecast to be a high generation cost month in 2025, it is forecast to be a high cost month when marginal distribution as well as generation costs are considered.

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21 Approximately one third of solar generation in California occurs at the distribution level (chiefly rooftop photovoltaic); the other two thirds is at the transmission, or generation level.

Based on both customer considerations such as rate stability and the impact of MDCs on total avoided costs, PG&E proposes to maintain the June-September summer season definition at this time, with the expectation that the possibility of a July-October definition will be revisited in PG&E's 2023 GRC Phase II Application.

D. Revisiting TOU Periods: PG&E's Dead Band Tolerance Criteria

1. Definition of PG&E's Dead Band Tolerance Criteria

PG&E's Dead Band Tolerance range (or equivalently, threshold to exceed) comprises two parts, both of which must be met to allow PG&E to consider revising TOU periods sooner than five years after the most recent change in TOU period (i.e., in this GRC Phase II Application).[22] The results of PG&E's analysis show that the Dead Band Tolerance range is exceeded for the peak period; however, PG&E is opting not to propose changing the Base TOU periods at this time, as exceeding the Dead Band Tolerance range merely suggests the option to propose changed hours but does not require it.[23] As discussed at the end of Section A, above, PG&E has serious concerns about changing its TOU periods in this proceeding, because most customers will have just seen a significant shift in TOU peak

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22 The conditions are: (1) Changed cost data justify changing either (a) the start or ending time of the TOU period by at least one hour (in either direction), for the summer peak, winter peak, or spring SOP; or (b) the months for which particular TOU period definitions apply; and (2) Using a forecast of MGCs, or whatever other marginal costs are used to determine TOU periods in a GRC Phase II proceeding, with the forecast year set at least three years after the year the Base TOU period will go into effect, the "goodness of separation" (GOS) metrics pertaining to the summer peak period, the winter peak period or the SOP period increase under the new TOU period definition by at least five percentage points (5%) relative to the corresponding GOS metrics using the old TOU period definition.

23 D.17-01-006, Appendix 1, p. 2, Section 6: "To evaluate whether a dead band tolerance range has been exceeded and to ensure that the Commission and the public are aware of the likelihood of future Base TOU period changes, Base TOU period analysis should be provided in each GRC, even if the IOU does not propose a change in Base TOU periods. If such analysis shows that the dead band tolerance range has been exceeded, the IOU should propose revisions to Base TOU periods."

hours[24] and PG&E believes rate stability, to avoid the risk of customer confusion, counsels waiting until the 2023 GRC Phase II Application to consider potential TOU period changes.

2. Calculation of Goodness of Separation Metrics for Peak TOU Periods

The definitions of GOS metrics and their components are provided in Attachment A. This section describes how those components were calculated and the resulting metrics for peak periods.

To evaluate summer and winter peak periods, PG&E determined the number of high-cost hours that occur during various potential on-peak periods in summer (June-September) and winter (October-May), using a forecast year of 2025, for each of the ten weather scenarios described in Chapter 2 of this exhibit, and then used the averages over all scenarios to develop GOS metrics. For example, to develop the GOS metric for a peak period of 4 p.m. – 9 p.m., PG&E set a "high cost flag" to one in each hour of the year 2025 forecast for each weather scenario if the MGC was in the top 5 percent of year 2025 hours for that weather scenario, and set the high cost flag to zero if the MGC was not in the top 5 percent of year 2025 hours. PG&E then took the average of the high cost flags over all scenarios to get an "average high cost flag" by hour of the year 2025 forecast. Those average high cost flags were used to calculate the expected number of true positive, false negative, true negative, and false negative hours for the 4 p.m. – 9 p.m. period, and thence the A and B factors and GOS metric.

The results for various summer On-Peak definitions are shown in Table 11-2; results for winter On-Peak periods are in Table 11-3; while Table 11-4 shows weighted average GOS metrics for the entire calendar year (which is appropriate if the TOU periods are required to be the same in summer and winter).

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24 These shifts include primarily the Commercial and Agricultural TOU Time Period transitions from the current Noon to 6 p.m. summer peak to the new 4 p.m. – 9 p.m. and 5 p.m. – 8 p.m. peak periods, as well as the default TOU transition of eligible Residential customers from a tiered rate plan with no TOU time period to a TOU rate with a 4 p.m. – 9 p.m. peak. Significant resources have been invested (and will continue to be invested during 2020-2021) in building customer awareness and understanding of the new 4 p.m. to 9 p.m. period for Residential and Commercial customers.

TABLE 11-2
GOODNESS OF SEPARATION METRICS FOR SUMMER 2025
BASED ON MARGINAL GENERATION COSTS

Line No.	Summer Peak Hours	True Pos. Hours	False Neg. Hours	False Pos. Hours	True Neg. Hours	True Pos. Rate A	False Pos. Rate B	GOS Metric
1	**4PM-9PM**	155.7	42.3	454.3	2275.7	78.6%	16.6%	**65.6%**
2	**5PM-9PM**	155	43	333	2397	78.3%	12.2%	**68.7%**
3	**5PM-10PM**	192.2	5.8	417.8	2312.2	97.1%	15.3%	**82.2%**
4	**6PM-10PM**	188.7	9.3	299.3	2430.7	95.3%	11.0%	**84.9%**

TABLE 11-3
GOODNESS OF SEPARATION METRICS FOR WINTER 2025
BASED ON MARGINAL GENERATION COSTS

Line No.	Winter Peak Hours	True Pos. Hours	False Neg. Hours	False Pos. Hours	True Neg. Hours	True Pos. Rate A	False Pos. Rate B	GOS Metric
1	**4PM-9PM**	211	29	1004	4588	87.9%	18.0%	**72.1%**
2	**5PM-9PM**	211	29	761	4831	87.9%	13.6%	**76.0%**
3	**5PM-10PM**	234.9	5.1	980.1	4611.9	97.9%	17.5%	**80.7%**
4	**6PM-10PM**	184.5	55.5	787.5	4804.5	76.9%	14.1%	**66.0%**

TABLE 11-4
GOODNESS OF SEPARATION METRICS FOR CALENDAR YEAR 2025
BASED ON MARGINAL GENERATION COSTS

Line No.	All-Year Peak Hours	True Pos. Hours	False Neg. Hours	False Pos. Hours	True Neg. Hours	True Pos. Rate A	False Pos. Rate B	GOS Metric
1	**4PM-9PM**	366.7	71.3	1458.3	6863.7	83.7%	17.5%	**69.1%**
2	**5PM-9PM**	366	72	1094	7228	83.6%	13.1%	**72.6%**
3	**5PM-10PM**	427.1	10.9	1397.9	6924.1	97.5%	16.8%	**81.1%**
4	**6PM-10PM**	373.2	64.8	1086.8	7235.2	85.2%	13.1%	**74.1%**

The GOS metrics shown in Tables 11-2 through 11-4 combine the two metrics that were used to determine proposed TOU periods in PG&E's 2017 GRC Phase II. In that earlier proceeding, PG&E reported the values for the true positive rate A and false positive rate B, and explained that an optimal TOU period would have a high value for A and a low value for B.[25] The GOS metric, calculated as A * (1-B), combines these preferences into a single metric, where a higher value for GOS generally implies a higher value

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[25] See A.16-06-013, Exhibit (PG&E-9), p. 12-14.

for A, a lower value for B, or some combination of the two. Thus, the TOU period definitions that have the highest GOS metrics are considered to best match the peak periods with high cost hours.

From Table 11-2, the summer peak TOU periods with the highest values of GOS are 5 p.m. – 10 p.m. and 6 p.m. – 10 p.m. Both of those periods are at least 1 hour later than the current summer peak period of 4 p.m. – 9 p.m., and both have a GOS that exceeds the GOS for the current peak period by more than five percent, so both of the criteria in PG&E's Dead Band Tolerance are exceeded for both of these later periods.

As for the winter peak period, Table 11-3 shows that both 5 p.m. – 9 p.m. and 5 p.m. – 10 p.m. have higher GOS than the current 4 p.m. – 9 p.m. winter peak, and 5 p.m. – 10 p.m. exceeds the GOS of the current peak by the established five percent Dead Band Tolerance threshold. The 6 p.m. – 10 p.m. peak period has a lower winter GOS than the current peak.

To minimize customer confusion, PG&E proposed harmonizing the peak periods between summer and winter in its 2017 GRC Phase II.[26] PG&E believes the same arguments for harmonization apply today. Thus, PG&E does not advocate for setting the peak to 6 p.m. – 10 p.m. in summer and 5 p.m. – 10 p.m. in winter (which would maximize GOS in each season separately), but considers which consistent all-year TOU period would maximize the *overall* GOS.[27] The results from that analysis are presented in Table 11-4, and indicate that the 5 p.m. – 10 p.m. period best matches the high cost hours (highest overall GOS). This is the same period PG&E proposed in its 2017 GRC Phase II, where it also found

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26 See A.16-06-013, Exhibit (PG&E-9), p. 12-16, footnote 13.

27 The current analysis assumes that California will continue to use Daylight Saving Time (DST). However, there are various proposals to eliminate DST or to apply it year-round, which could come into force during the life of this Application. If DST were to be eliminated (so Pacific Standard Time applied all year), a 5 p.m. – 9 p.m. peak period would likely best align with high cost hours in both summer and winter; while if DST applied all year a 6 p.m. – 10 p.m. peak period would likely best align with high cost hours in both summer and winter. However, while the impact of a DST change on average solar and wind production by TOU period is easily determined, changing the DST usage could affect load in complex ways, so more analysis would be required to confirm these expectations.

5 p.m. – 10 p.m. to have the best match to high cost hours.[28] Considering this year-round metric, the later period meets the Dead Band Tolerance criterion, since the GOS for 5 p.m. – 10 p.m. is 12 percent (81.1 – 69.1) better than the GOS for the current 4 p.m. – 9 p.m. period.[29]

PG&E also calculated GOS metrics based on the combination of MGCs and MDCs; results are shown in Tables 11-5 through 11-7.

TABLE 11-5
GOODNESS OF SEPARATION METRICS FOR SUMMER 2025
BASED ON MARGINAL GENERATION PLUS DISTRIBUTION COSTS

Line No.	Summer Peak Hours	True Pos. Hours	False Neg. Hours	False Pos. Hours	True Neg. Hours	True Pos. Rate A	False Pos. Rate B	GOS Metric
1	**4PM-9PM**	255.4	60.6	354.6	2257.4	80.8%	13.6%	**69.9%**
2	**5PM-9PM**	244.1	71.9	243.9	2368.1	77.2%	9.3%	**70.0%**
3	**5PM-10PM**	291.1	24.9	318.9	2293.1	92.1%	12.2%	**80.9%**
4	**6PM-10PM**	263.3	52.7	224.7	2387.3	83.3%	8.6%	**76.2%**

28 PG&E and other parties settled on the 4 p.m. – 9 p.m. peak period for the 2017 GRC Phase II, partly to align PG&E's TOU peak period with those of the other IOUs, which were proposing a 4 p.m. – 9 p.m. peak period. However, marginal cost values were neither litigated nor proposed in the settlement agreement adopted in PG&E's 2017 GRC. PG&E is here referring to its calculated metrics based on its proposed marginal costs in that proceeding.

29 Note that in its November 22, 2019 GRC filing (in which the Dead Band Tolerance was not exceeded for the Peak period), PG&E suggested that GOS metrics were unlikely to change significantly in this July update, since the GOS metrics are based on the timing rather than the magnitude of marginal generation and distribution costs. However, PG&E now realizes that in this July update, the marginal generation *capacity* costs (MGCC) increased substantially compared to the November 2019 filing, while MEC were relatively unchanged or even flattened by the addition of energy storage modeling. Out of the three marginal costs considered in this chapter (MEC, MGCC and MDC), MGCC has the latest peak, because the Adjusted Net Load (ANL) that is used to calculate its 8760 shapes includes the impact of both behind- and front-of-the meter solar generation (thus peaking later than MDCs, which are only affected by behind-the-meter solar), and does *not* include the impact of ramping and temperature effects in the rest of the Western Electricity Coordinating Council, both of which shift the peak of MECs earlier than the peak of ANL (as discussed in Chapter 2). Thus higher MGCCs relative to the other components used in the GOS calculation tend to shift the peak later, and thus increase the difference between the GOS of the current 4 p.m. – 9 p.m. peak and the later peak periods examined here.

TABLE 11-6
GOODNESS OF SEPARATION METRICS FOR WINTER 2025
BASED ON MARGINAL GENERATION PLUS DISTRIBUTION COSTS

Line No.	Winter Peak Hours	True Pos. Hours	False Neg. Hours	False Pos. Hours	True Neg. Hours	True Pos. Rate A	False Pos. Rate B	GOS Metric
1	**4PM-9PM**	114.8	7.2	1100.2	4609.8	94.1%	19.3%	**76.0%**
2	**5PM-9PM**	111	11	861	4849	91.0%	15.1%	**77.3%**
3	**5PM-10PM**	117.3	4.7	1097.7	4612.3	96.1%	19.2%	**77.7%**
4	**6PM-10PM**	96.7	25.3	875.3	4834.7	79.3%	15.3%	**67.1%**

TABLE 11-7
GOODNESS OF SEPARATION METRICS FOR CALENDAR YEAR 2025
BASED ON MARGINAL GENERATION PLUS DISTRIBUTION COSTS

Line No.	All-Year Peak Hours	True Pos. Hours	False Neg. Hours	False Pos. Hours	True Neg. Hours	True Pos. Rate A	False Pos. Rate B	GOS Metric
1	**4PM-9PM**	370.2	67.8	1454.8	6867.2	84.5%	17.5%	**69.7%**
2	**5PM-9PM**	355.1	82.9	1104.9	7217.1	81.1%	13.3%	**70.3%**
3	**5PM-10PM**	408.4	29.6	1416.6	6905.4	93.2%	17.0%	**77.4%**
4	**6PM-10PM**	360	78	1100	7222	82.2%	13.2%	**71.3%**

Comparing Table 11-5 to Table 11-2, both True Positive and False Negative hours are greater for the combined costs than for MGCs alone. This is because MDCs are concentrated in the summer more than MGCs are, so all TOU periods shown here have more high cost hours total in the summer when Distribution costs are included. The GOS for the 4 p.m. – 9 p.m. and 5 p.m. – 9 p.m. periods are greater when Distribution costs are included; later TOU periods (especially the 6 p.m. – 10 p.m. period) show lower GOS when Distribution costs are included.

Comparing Table 11-6 to Table 11-3, both True Positive and False Negative hours are lower for the combined costs than for MGCs alone, while all winter TOU periods except 5 p.m. – 10 p.m. show higher GOS when Distribution costs are included.

Finally, comparing Table 11-7 to 11-4, all year-round TOU periods except for 4 p.m. – 9 p.m. show lower GOS metrics when Distribution costs are included, with the 5 p.m. – 10 p.m. period showing greater reductions than the other TOU periods. Based on this analysis, if MDCs were included in the TOU period analysis, the 5 p.m. – 10 p.m. TOU period would again be shown to be the most aligned with marginal Generation plus Distribution costs. Furthermore, the Dead Band Tolerance threshold of five percent would again be exceeded, since the GOS for 5 p.m. – 10 p.m. is 7.7 percent (77.4 – 69.7) better than the GOS for the current 4 p.m. – 9 p.m. period. However, based on the discussion above regarding providing rate stability for customers as they are transitioned to new rates and new TOU periods over the next few years, PG&E believes that the peak period for both summer and winter should remain 4 p.m. – 9 p.m. at this time.

3. Calculation of GOS Metrics for Super Off-Peak TOU Periods

PG&E performed similar calculations to test various combinations of months and hours for the SOP period. For this analysis, PG&E considered both the current start time of 9 a.m. and the SOP start time of 8 a.m. that applies in Southern California Edison Company's (SCE) rates;[30] and hourly ending times from the current 2 p.m. through 5 p.m. In addition, PG&E considered three seasonal definitions: (1) the current SOP season of March-May; (2) March-June; and (3) November-June (i.e., all months except for the summer months of July-October that were shown to be preferred in Section C). The calculations and resulting GOS metrics for all combinations are shown in Figure 11-4.

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[30] SCE has an 8 a.m. – 4 p.m. SOP during the winter (October-May) in its TOU-D-4-9PM rate, and a winter SOP from 8 a.m. – 5 p.m. in its TOU-D-5-8PM rate. See https://pages.email.sce.com/RatePlanOptions/en (accessed November 14, 2019).

FIGURE 11-4
GOS CALCULATIONS FOR VARIOUS SOP PERIODS
FOR CALENDAR YEAR 2025
BASED ON MARGINAL GENERATION COSTS

Season	HB Start	HE End	True Pos.	False Neg.	False Pos.	True Neg.	True Pos A	False Pos B	GOS
Mar-May	9	14	412.8	335.1	47.2	1412.9	55.2%	3.2%	53.4%
Nov-Jun			712.3	482.4	497.7	4115.6	59.6%	10.8%	53.2%
Mar-Jun			534.7	420.8	75.3	1897.2	56.0%	3.8%	53.8%
Mar-May	8	14	470.1	277.8	81.9	1378.2	62.9%	5.6%	59.3%
Nov-Jun			802	392.7	650	3963.3	67.1%	14.1%	57.7%
Mar-Jun			613.6	341.9	118.4	1854.1	64.2%	6.0%	60.4%
Mar-May	9	15	496.3	251.6	55.7	1404.4	66.4%	3.8%	63.8%
Nov-Jun			850.3	344.4	601.7	4011.6	71.2%	13.0%	61.9%
Mar-Jun			639.6	315.9	92.4	1880.1	66.9%	4.7%	63.8%
Mar-May	8	15	553.6	194.3	90.4	1369.7	74.0%	6.2%	69.4%
Nov-Jun			940	254.7	754	3859.3	78.7%	16.3%	65.8%
Mar-Jun			718.5	237	135.5	1837	75.2%	6.9%	70.0%
Mar-May	9	16	575.4	172.5	68.6	1391.5	76.9%	4.7%	73.3%
Nov-Jun			963.6	231.1	730.4	3882.9	80.7%	15.8%	67.9%
Mar-Jun			736.4	219.1	117.6	1854.9	77.1%	6.0%	72.5%
Mar-May	8	16	632.7	115.2	103.3	1356.8	84.6%	7.1%	78.6%
Nov-Jun			1053.3	141.4	882.7	3730.6	88.2%	19.1%	71.3%
Mar-Jun			815.3	140.2	160.7	1811.8	85.3%	8.1%	78.4%
Mar-May	9	17	641.4	106.5	94.6	1365.5	85.8%	6.5%	80.2%
Nov-Jun			1042.1	152.6	893.9	3719.4	87.2%	19.4%	70.3%
Mar-Jun			813.7	141.8	162.3	1810.2	85.2%	8.2%	78.2%
Mar-May	**8**	**17**	**698.7**	**49.2**	**129.3**	**1330.8**	**93.4%**	**8.9%**	**85.1%**
Nov-Jun			1131.8	62.9	1046.2	3567.1	94.7%	22.7%	73.3%
Mar-Jun			892.6	62.9	205.4	1767.1	93.4%	10.4%	83.7%

In the above figure, each set of three rows correspond to the three seasonal definitions using the designated TOU period; the sets of rows are organized such that lower rows have either earlier starting times or later ending times (thus, longer SOP periods). The current SOP definition (9 a.m. – 2 p.m., March-May) is shown on the first row, and actually has the lowest GOS of all combinations tested.

Within each set of three rows, the highest GOS is highlighted; the highest GOS over all combinations (corresponding to the March-May SOP season and SOP hours of 8 a.m. – 5 p.m.) is highlighted over the entire row. PG&E notes that while the 8 a.m. start time always yields a higher GOS than a 9 a.m. start for the same season and end-time (i.e., the GOS for each 8 a.m. start row is greater than the GOS for the 9 a.m. start three rows up), the seasonal pattern is much less consistent, except that all the SOP periods that end at 4 p.m. or 5 p.m. (i.e., the last four sets of rows) show the highest GOS metric with the current March through May SOP season, with March through June GOS metrics at most 2% worse.

PG&E also calculated GOS metrics for the SOP using combined Generation and Distribution costs; results are shown in Figure 11-5. The results shown in Figure 11-5 are almost identical to those in Figure 11-4, with individual GOS metrics changing by at most 1.2 percent, and the ordering of TOU periods and seasonal combinations (e.g., within each set of three and among TOU periods) almost identical between the MGC-only and combined cost results.

FIGURE 11-5
GOS CALCULATIONS FOR VARIOUS SOP PERIODS
FOR CALENDAR YEAR 2025
BASED ON MARGINAL GENERATION AND DISTRIBUTION COSTS

Season	HB Start	HE End	True Pos.	False Neg.	False Pos.	True Neg.	True Pos A	False Pos B	GOS
Mar-May	9	14	408.6	323.4	51.4	1424.6	55.8%	3.5%	53.9%
Nov-Jun			695	458	515	4140	60.3%	11.1%	53.6%
Mar-Jun			518.1	396.6	91.9	1921.4	56.6%	4.6%	54.1%
Mar-May	8	14	464.6	267.4	87.4	1388.6	63.5%	5.9%	59.7%
Nov-Jun			782.3	370.7	669.7	3985.3	67.8%	14.4%	58.1%
Mar-Jun			594.6	320.1	137.4	1875.9	65.0%	6.8%	60.6%
Mar-May	9	15	490.4	241.6	61.6	1414.4	67.0%	4.2%	64.2%
Nov-Jun			828.4	324.6	623.6	4031.4	71.8%	13.4%	62.2%
Mar-Jun			618.4	296.3	113.6	1899.7	67.6%	5.6%	63.8%
Mar-May	8	15	546.4	185.6	97.6	1378.4	74.6%	6.6%	69.7%
Nov-Jun			915.7	237.3	778.3	3876.7	79.4%	16.7%	66.1%
Mar-Jun			694.9	219.8	159.1	1854.2	76.0%	7.9%	70.0%
Mar-May	9	16	568.1	163.9	75.9	1400.1	77.6%	5.1%	73.6%
Nov-Jun			937.1	215.9	756.9	3898.1	81.3%	16.3%	68.1%
Mar-Jun			710.8	203.9	143.2	1870.1	77.7%	7.1%	72.2%
Mar-May	8	16	624.1	107.9	111.9	1364.1	85.3%	7.6%	78.8%
Nov-Jun			1024.4	128.6	911.6	3743.4	88.8%	19.6%	71.4%
Mar-Jun			787.3	127.4	188.7	1824.6	86.1%	9.4%	78.0%
Mar-May	9	17	630.6	101.4	105.4	1370.6	86.1%	7.1%	80.0%
Nov-Jun			1007.9	145.1	928.1	3726.9	87.4%	19.9%	70.0%
Mar-Jun			780.4	134.3	195.6	1817.7	85.3%	9.7%	77.0%
Mar-May	**8**	**17**	**686.6**	**45.4**	**141.4**	**1334.6**	**93.8%**	**9.6%**	**84.8%**
Nov-Jun			1095.2	57.8	1082.8	3572.2	95.0%	23.3%	72.9%
Mar-Jun			856.9	57.8	241.1	1772.2	93.7%	12.0%	82.5%

Whether or not the analysis includes Distribution costs, the SOP definition that most aligns with the incidence of very low-cost hours (with marginal costs at or below zero) runs from March through May and applies from 8 a.m. to 5 p.m. The end of that period aligns with the start of the peak period with the highest GOS metric determined in Subsection 2, above. So, if the peak period were to be changed to 5 p.m. to 10 p.m., the SOP in earlier months would align with it, and therefore be easy to remember. PG&E also notes that the GOS metric for the March-June 8 a.m. – 5 p.m. SOP definition is the second highest of all tested combinations. Thus, if the summer definition were changed to July-October it could make sense to continue the SOP season through June to align its end with the start of summer. Both the March through May, 8 a.m. – 5 p.m. and March through June, 8 a.m. – 5 p.m. definitions have GOS metrics that exceed the five percent threshold improvement. Finally, the March-May, 8 a.m. – 4 p.m. and 9 a.m. – 4 p.m. SOP definitions also show greater than five percent GOS improvement over the current definition.

If PG&E were to propose a change to the SOP at this time, the most customer-friendly update that would improve alignment with the incidence of 2025 forecast very low-cost hours would be a change to 8 a.m. – 4 p.m. This would match SCE's TOU-D-4-9PM SOP period and would align the end of the SOP with the start of the current peak period, rather than the start of the summer shoulder peak period as at present. An alternative would be 9 a.m. – 4 p.m., which keeps the current 9 a.m. start time and would also align with the start of the peak period.

However, as with the definition of the summer season and the TOU peak period, PG&E believes that changing the definition of the SOP period so soon after its implementation in Commercial and Industrial rates in 2019-2020 would cause customer confusion and should not be adopted at this time. The next opportunity to re-examine the definition of the SOP would be in PG&E's 2023 GRC Phase II, and should be based on a holistic examination of seasonal and TOU period definitions, as well as other considerations at that time.

E. Conclusion

PG&E presents in this Chapter the time-differentiated portion of MDCs, and provides information regarding TOU-based applications at FERC, and the status of DER valuation proceedings. PG&E also considers whether TOU periods, and seasons, should shift based on updated marginal costs and the Dead Band Tolerance criteria established in Advice Letter 5037-E-A. Whether the analyses of TOU periods and seasons are based on just MGCs or also include MDCs, PG&E proposes to maintain the same seasons and TOU periods that were adopted in PG&E's 2017 GRC Phase II, to avoid customer confusion so soon after the current seasons and TOU periods are implemented in 2020 and 2021.

PG&E requests the Commission accept PG&E's showing of MDCs and other required information and retain the most recently adopted TOU periods and seasons as proposed by PG&E in this testimony.

Attachment RII-3
Excerpt from SBUA Direct Testimony,
PG&E Phase 2 GRC A.19-11-019

E. TOU Periods

Q: What periods does PG&E use for TOU pricing?

A: The time periods are shown in Table 4.

Table 4: PG&E TOU Periods

	Months	Hours
Summer Peak	June – September	4 – 9 PM
Summer Part-Peak		2 – 4 PM, 9 – 11 PM
Winter Peak	October – May	4 – 9 PM
Super Off Peak	March – May	9 – 2 PM

Source: PG&E July 2020 Errata Testimony, Exhibit 3, Ch. 4, Att. B, p. 1.

Q: Did PG&E select appropriate TOU periods?

A: Not entirely. PG&E reviewed its monthly and hourly TOU period decisions that were adopted in D.18-08-013. Although PG&E acknowledges that its analysis could support changing the definitions, PG&E recommends no changes to those decisions in order to avoid customer confusion so soon after adopting the current TOU periods.

PG&E acknowledges that its analysis justifies changes to the peak and super off peak (SOP) TOU periods, including:

- Shifting the summer months from the current June – September to July – October;
- Shifting the peak hours for both summer and winter months from the current 4 – 9 PM to 5 – 10 PM; and
- Shifting the SOP period from the current March – May, 9 AM – 2 PM period to March – May, 8 AM – 4 PM.

PG&E does not discuss the summer part-peak period.

We have reviewed PG&E's Dead Band Tolerance method and our opinion is that the method employed is reasonable and that it is effectively applied. However, for reasons discussed below, we suggest that the Commission take action in this proceeding to revise PG&E's TOU periods.

Q: What considerations suggest that PG&E's TOU periods should be revised in this proceeding?

A: One major consideration that PG&E does not discuss is the role of TOU periods, and the SOP rate in particular, in encouraging adoption of electric vehicles (EVs). This is a substantial topic of discussion in the draft Transportation Electrification Framework (TEF), under review in A.18.12.006.

While we agree that PG&E's concern about customer confusion is warranted, waiting until the 2023 GRC will result in a substantial delay in implementing TOU period revisions. It is likely that a decision on the question would not be issued until 2024, and then PG&E would need time to educate customers prior to making the TOU period revisions, so it is possible that the changes would not occur until late 2024 or even sometime in 2025.

The urgency of using all available policy tools to promote electric vehicles adoption and charging during more optimal periods warrants consideration of an earlier timeline to implement an evidence-based shift to a more expansive SOP TOU period.

Q: Please describe PG&E's analysis of the period for the Super Off Peak.

A: PG&E found that its current Super Off Peak rate is using a very poor TOU period definition. Of all the SOP period definitions tested using its goodness of separation (GOS) method, PG&E found that "The current SOP definition … actually has *the lowest GOS of all combinations tested*."[21] This is true for

[21] PG&E Testimony, Exhibit 2, Ch. 11, p. 20, lines 4-7.

the analysis with marginal generation costs only and is nearly true for the analysis that adds in marginal distribution costs.[22]

The highest GOS of all SOP period definitions tested is identified for the March – May, 8 AM – 5 PM combination,[23] with the March – June, 8 AM – 5 PM combination not very far behind. The only other month span tested by PG&E is November – June.

Even though PG&E identifies the 8 AM – 5 PM period as optimal, PG&E recommends that if a change is to be made, the SOP should be March – May, 8 AM – 4 PM. The 4 PM end time is recommended because it would be more "customer-friendly" by "align[ing] the end of the SOP with the start of the current peak period."[24] The GOS difference between the best option and the 4 PM end time option recommended by PG&E is 6.5% for MGCCs only, and 6.0% for MGCCs and MDCCs combined, which exceeds PG&E's dead band tolerance threshold of 5.0% for considering a change to the TOU period. Thus, by PG&E's definition, the March – May, 8 AM – 5 PM option has a significantly better GOS than the 4 PM end time alternative recommended by PG&E.

Not only is the 8 AM – 5 PM SOP TOU period optimal under PG&E's test, but it aligns best with PG&E's optimal peak period. As noted above, the optimal peak period begins at 5 PM, not 4 PM.

Q: What SOP TOU period do you recommend?

A: First, with respect to the hours, we recommend that the Commission direct PG&E to change the SOP period to 8 AM – 5 PM. PG&E's evidence demonstrates that this rate design is the optimal SOP period, performing more

[22] PG&E Testimony, Exhibit 2, Ch. 11, pp. 20, 22, Figures 11-4 and 11-5.

[23] PG&E Testimony, Exhibit 2, Ch. 11, pp. 20, 22, Figures 11-4 and 11-5.

[24] PG&E Testimony, Exhibit 2, Ch. 11, p. 23, lines 9, 11-13.

than 5% better than PG&E's preferred change. In contrast, PG&E's preferred change is less well aligned with costs and does not align with the optimal peak rate, and thus is not necessarily customer-friendly in the long term.

With respect to the months, we recommend that PG&E offer the SOP rate from February to June. Increasing the number of SOP rate months from three to five would help promote EV adoption and charging during optimal periods. Small businesses, in particular, would be more likely to see a benefit from installing EV charging infrastructure if SOP period was available for more than just three months of the year.

We developed this recommendation in two steps. First, we reviewed PG&E's GOS analysis for November – June. It is evident that marginal costs are consistent with the intent of the SOP period quite often during this extended period. Compared with March – May, the number of true positives (hours with marginal costs at or below zero) is increased from 687 to 1,095. However, this is offset by the large number of false positives (SOP hours with marginal costs above zero).

Because there was evidence that encouraging power use during the SOP period for those additional months would be of some benefit, but also have some potential for cost, we conducted a monthly analysis. Our analysis considered both MGCCs and MDCCs.

First, we looked at the distribution of marginal costs by month during our recommended SOP hours of 8 AM – 5 PM. As shown in Table 5, the best months are indeed March – May, but more than half of the hours in February and June have a total MGCCs and MDCCs of less than $10 per MWh.

Table 5: Marginal Costs (MGCCs and MDCCs) During Super Off Peak Period (8 AM – 5 PM)

	Marginal Costs </= $0 /MWh	Marginal Costs $0 - $10 /MWh	Marginal Costs > $10 /MWh
November	16%	13%	71%
December	7%	7%	85%
January	18%	11%	71%
February	49%	9%	42%
March	72%	10%	18%
April	90%	5%	5%
May	87%	7%	6%
June	63%	15%	22%

Second, we looked at the average marginal costs by month and by TOU period, based on our recommended hours for SOP and Peak rate periods. As shown in Table 6, the average SOP marginal costs in February and June are $10.20 and $2.68 per MWh, respectively. While higher than the average marginal costs in March – May, SOP marginal costs in February and June are significantly lower than SOP marginal costs in other months of the year.

Perhaps more importantly, the differential between SOP and Off Peak marginal costs in February and June is not much lower than in May. The SOP in February does not compete for load with the SOP in March or May; the February SOP draws load away from the February Off Peak period, by giving customers a signal to charge their EVs and run their schedulable loads in the sunshine hours rather than overnight. In contrast, the months of November, December and January have both a higher frequency of hours with marginal costs greater than $10 per MWh as well as a much smaller differential between SOP and Off Peak marginal costs.

Table 6: Average Marginal Costs (MGCCs and MDCCs), by Rate Period ($ per MWh)

	Super Off Peak 8 AM – 5 PM	Off Peak 10 PM – 8 AM	Peak 5 PM – 10 PM	Off Peak / Super Off Peak Differential
November	23.22	49.60	109.13	26.37
December	32.65	55.00	114.22	22.35
January	24.99	55.97	81.09	30.98
February	10.20	52.77	71.33	42.57
March	- 2.02	46.99	55.64	49.01
April	- 9.88	41.63	45.61	51.50
May	- 8.01	37.12	50.98	45.13
June	2.68	38.59	148.47	35.91

Based on our analysis, we have two recommendations. First, the SOP start month should be February, rather than March.

Second, the existing evidence favors ending the SOP period in June. Nevertheless, we agree with PG&E that it makes sense to align the end of the SOP season with the beginning of the summer season. Currently, the summer season begins in June so the SOP rate should end in May. However, if the summer period is shifted to begin in July, the SOP rate should end in June.

Expanding the SOP season to five months has two advantages. First, it better aligns rates with costs, and will help shift load to high-solar hours in the late winter and spring. Second, an extended SOP season will align EV and storage charging with marginal costs over a larger period of the year. Our recommendation balances the concern about incentivizing uneconomic energy use with the Commission's interest in expanding low rate periods to incentivize EV and storage charging.

Q: When should PG&E make the change to the SOP rate period?

A: The Commission should direct PG&E to review its implementation schedule for the current TOU rate periods and identify the earliest possible date in which the Company would be able to roll out an effective customer education program for the change in the SOP rate period. PG&E should be directed to file a Tier 3 Advice Letter identifying the date at which it proposes to implement the change, along with its rationale for the selected date.

The Advice Letter should also provide PG&E's reconsideration of the starting and ending months, as discussed above. We have confidence that PG&E's review of this question can be fairly straightforward and thus will not require significant review by other parties. We recommend that it be included in the Advice Letter because the analysis will be of interest to parties for future proceedings.

If the only change made to the TOU periods is the expansion of the SOP rate period, we do not believe this will cause customer confusion that negatively affects rollout of mandatory TOU rates. In fact, it may assist with the marketing: PG&E can easily announce this change as an additional rate discount option. When have customers ever been confused because a sale price was extended?

Q: Should the Commission also direct PG&E to adjust its summer peak hours?

A: This is a closer call, but we also recommend that the Commission direct PG&E to make these changes as well. Firstly, both shifting the summer peak months to July – October and shifting all peak hours to 5 – 10 PM are merited by PG&E's analysis.

However, we would acknowledge that the benefit of making these changes is not as substantial as the SOP period definition changes discussed above. In addition to better aligning the peak periods with marginal costs, changing the peak period definitions would also support the SOP period definition changes discussed above. These benefits of making the changes, while less substantial than the SOP period definition changes, also appear fairly robust given the evidence provided by PG&E.

As discussed above, we agree that PG&E's concern about customer confusion is warranted, and is somewhat stronger for shifting the peak hours and summer peak months. Yet waiting until the 2023 GRC will result in a substantial delay in implementing TOU period revisions. If customer confusion concerns can be alleviated, we recommend that the Commission should direct PG&E to move forward with these changes to the definitions.

The Commission can provide a measured pace in the path forward by authorizing PG&E to:

- Make changes to the peak period definitions concurrent with the SOP period changes at its option in the same Advice Letter; or
- File a separate Advice Letter at any point prior to filing its 2023 GRC with changes to the peak period definitions, along with supporting evidence.

In either case, the Commission's authorization would be permissive, allowing the issue to be deferred to the 2023 GRC at PG&E's option.

Q: Does this conclude your testimony?

A: Yes.

Attachment RII-4
Excerpt from SCE TOU Period Study,
SCE Phase 2 GRC A.20-10-012

SCE TOU Period Study

I. Introduction and Summary of Existing Time-of Use Rate Structure

Time-of-use (TOU) rates improve the "price signals" that utility customers see as a result of their consumption decisions and result in improved economic efficiency in comparison to flat rates, which do not vary by time of day or season.[1] Since it would be impractical to have rates that vary hourly based on a forecast, a set of well-designed TOU periods provides a balance between the objectives of practical retail pricing and economic efficiency. The key objective in determining a set of TOU periods is to group together hours with similar marginal costs and differentiate hours with marginal costs that are not similar, while limiting the overall number of costing periods. The current standard TOU periods which SCE proposed in its 2016 RDW and were subsequently adopted in D.18-07-006 are as follows:

Table D-1
SCE Current Base TOU Periods for Non-Residential Customers

Time-of-Use Period	Summer (June-September)	Winter (October – May)
On-Peak	4:00 p.m. – 9:00 p.m. Non-Holidays, Weekdays	n/a
Mid-Peak	4:00 p.m. – 9:00 p.m. Weekends	4:00 p.m. – 9:00 p.m.
Off-Peak	All other hours	9:00 p.m. – 8:00 a.m.
Super-Off-Peak	n/a	8:00 a.m. – 4:00 p.m.

In each GRC cycle, SCE performs a costing period study to determine whether a change in the TOU rate structure is warranted based on marginal cost considerations. Based on the review of 2024 marginal costs described herein, SCE concludes that the ***current*** TOU periods appropriately reflects the distribution of generation and distribution marginal costs on a seasonal and time-of-day basis. This conclusion takes into account the total marginal costs forecast in SCE's service area for the year 2024.

[1] Well-designed TOU periods increase economic efficiency by discouraging customers from using electricity for low value applications during times when the cost of producing the electricity is high, and conversely encouraging customers to use electricity for low value applications when the cost of producing the electricity is low. This is an improvement over flat rates, which may result in customers consuming electricity that costs more to produce than the value gained by the customer or alternatively results in a customer foregoing consumption that would have been more valuable than the cost to produce the electricity.

II. Framework for Analysis

In this exhibit, SCE has described, in detail, the methodology and framework used when estimating different marginal cost components. The time-differentiated cost components used to test the goodness of fit for TOU periods are generation marginal energy costs, marginal generation capacity costs, and peak capacity-related distribution marginal costs. The sum of all these costs are referred to as *total marginal costs* in this Appendix. All other marginal cost components are considered non-time differentiated and excluded from the analysis.

SCE's current TOU periods define the summer season to include the months of June through September with the remaining months included in the winter season. The TOU periods have been defined to also include on-peak, mid-peak, off-peak and super-off-peak periods. Peak periods generally reflect times when marginal costs are higher due to the impacts of load and supply constraints on the system. The mid-peak period represents intermediate times where the likelihood of stress conditions results in marginal costs that are at moderate levels compared to the on-peak period. SCE expects that marginal costs in the winter mid-peak period will be increasingly affected by the need for flexible resources in meeting ramp constraints on the system. The off-peak period reflects times when loads are low, resulting in marginal costs that are generally lower than the peak (on and mid) periods. The winter super-off peak is a period where marginal costs are at their lowest levels, caused by the over-supply of renewable generation expected in that period.

In addition to a visual inspection of how TOU periods align with the hourly and seasonal dispersion of marginal costs, SCE performed a quantitative analysis of "goodness of fit" of the current periods. This analysis is presented in Sections III and IV, below.

III. Cost Analysis

In this section, variations in SCE's TOU periods are investigated. As described in Section II, this analysis is based on total marginal costs for the year 2024, with adjusted R^2 used as the "goodness of fit" measure. The specific scenarios investigated are summarized in Table D-2. A linear regression can be used to estimate the goodness of fit for a particular model to explain cost by calculating a best fit line through the data. The difference between the best fit line and the observed value is known as a residual. Two different models can be evaluated by comparing the adjusted R^2, and the model with the higher adjusted R^2 has a better fit. The regression model uses marginal cost as the dependent variable and a number of binary variables to represent TOU periods, season, and other variables that can influence the marginal cost.

Regression Analysis on Costs

A linear regression can be used to estimate the goodness of fit for a particular model to explain load by calculating a best fit line through the data. The goodness of fit of the model to the data is captured by the adjusted R^2.[2]

The regression model is the following:

$$TMC_t = \alpha_0 + \beta_1 * Summer * OnPeak$$
$$+\beta_2 * Summer * MidPeak$$
$$+\beta_3 * Summer * OffPeak$$
$$+\beta_4 * Winter * MidPeak$$
$$+\beta_5 * Winter * SuperOffPeak$$

Where: Summer, Winter, OnPeak, MidPeak, OffPeak, and SuperOffPeak is equal to one for each respective season and time periods and zero otherwise. The combination of season and TOU period creates an interaction variable. These variables capture the effect of both binary variables being true at the same time. The omitted season/TOU period is Winter Off Peak.[3] The coefficients, the $\beta_i's$, represent the effect of the interaction term on TMC. That is how much TMC increases in the Summer On Peak, for example, is given by β_1. The intercept term $\alpha_0$is the TMC at time *t* when all of the other variables are zero and this represents Winter Off Peak. The Top 20 variable is a binary variable singling out the twenty hours with the highest cost.

In this regression model, the estimated values for the beta coefficients give the differences between the mean values of the total marginal cost falling within different season and time period categories. Thus, the regression equation defines a step function that best explains the total marginal cost by season and TOU period.

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[2] For additional discussion of measures of “goodness of fit,” *see* Greene, William H., Econometric Analysis, 2nd Edition (New York, NY: Prentice Hall, 1993), 191-193.

[3] Including this variable along with an intercept would result in perfect multi-collinearity, which results in estimation not being possible.

The regression analysis will look at two TOU period scenarios. The first is the existing TOU time periods (Case A) and the second is an alternative with an on-peak period of 5-8pm (Case B)[4]. Both are analyzed using the regression methodology described above and the adjusted R^2's are compared to determine which model provides a better fit to the data. In presenting results, the adjusted R^2 value of each of these scenarios is presented in Table D-4.

Tables D-2 and D-3 present the regression results for the current and alternate scenarios respectively. These results contain a number of statistics include the adjusted R^2s and the estimated coefficients noted above (the β and α coeffiencts). For example, the intercept (α) for the current scenario represents $0.03630 for the Winter Off Peak period. For the alternate scenario, the intercept has a value of $0.03503 for the Winter Off Peak. Similar interpretations can be applied to the other coefficient estimates. The estimate of the intercept is the average cost of the Winter Off Peak and the remaining coefficient estimates are additional costs relative to the omitted period (Winter Off Peak). Coefficients that have been bolded represent statistical significance at the 95 percent level.

4 This TOU period structure is currently offered as an option to SCE's Residential customers.

Table D-2
Regression Results for Current TOU Period

Number of Observations Read	8784
Number of Observations Used	8784

Analysis of Variance					
Source	**DF**	**Sum of Squares**	**Mean Square**	**F Value**	**Pr > F**
Model	6	299.29029	49.88172	3952.01	<.0001
Error	8777	110.78204	0.01262		
Corrected Total	8783	410.07233			

Root MSE	0.11235	**R-Square**	0.7298
Dependent Mean	0.05324	**Adj R-Sq**	0.7297
Coeff Var	211.016		

Parameter Estimates					
Variable	**DF**	**Parameter Estimate**	**Standard Error**	**t Value**	**Pr > |t|**
Intercept	1	0.03630	0.00217	16.74	<.0001
Summer Mid	1	0.04864	0.00843	5.77	<.0001
Summer On	1	0.14919	0.00595	25.08	<.0001
Winter Super Off	1	-0.01752	0.00334	-5.24	<.0001
Summer Off	1	0.00650	0.00319	2.04	0.0413
Winter Mid	1	0.01788	0.00388	4.61	<.0001
Top 20	1	3.71270	0.02540	146.18	<.0001

Table D-3
Regression Results for <u>Alternate</u> TOU Period

Number of Observations Read	8784
Number of Observations Used	8784

Analysis of Variance					
Source	**DF**	**Sum of Squares**	**Mean Square**	**F Value**	**Pr > F**
Model	6	298.47919	49.74653	3912.65	<.0001
Error	8777	111.59314	0.01271		
Corrected Total	8783	410.07233			

Root MSE	0.11276	**R-Square**	0.7279
Dependent Mean	0.05324	**Adj R-Sq**	0.7277
Coeff Var	211.7871		

Parameter Estimates					
Variable	**DF**	**Parameter Estimate**	**Standard Error**	**t Value**	**Pr > |t|**
Intercept	1	0.03503	0.00218	16.10	<.0001
Summer Mid	1	0.04835	0.00846	5.71	<.0001
Summer On	1	0.14549	0.00598	24.34	<.0001
Winter Super Off	1	-0.01377	0.00335	-4.10	<.0001
Summer Off	1	0.00879	0.00320	2.75	0.0060
Winter Mid	1	0.01795	0.00389	4.61	<.0001
Top 20	1	3.71257	0.02552	145.46	<.0001

Table D-4
Comparison of Goodness of Fit in Regression Analysis
Current TOU–8 Peak Periods vs. Proposed Peak Periods

Case	**Adjusted R^2 (higher number is better)**
Case A: Summer On-Peak 4-9 p.m..	0.7297
Case B: Summer On-Peak 5-8 p.m.	0.7277

The following graphs provide a graphical representation of the tabulated regression results above.

Figure D-1
Graphical Representation of Regression Analysis on Current TOU Periods Marginal Cost

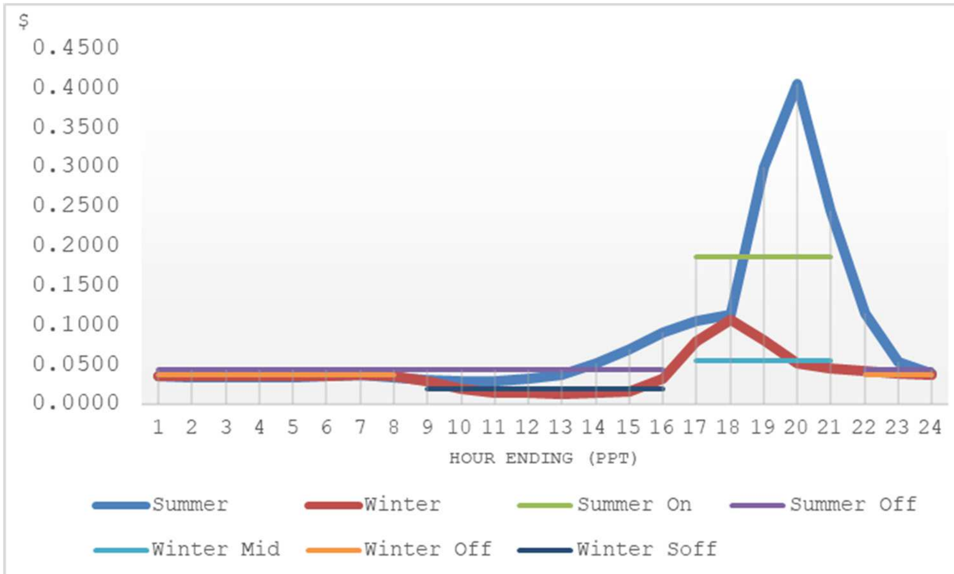
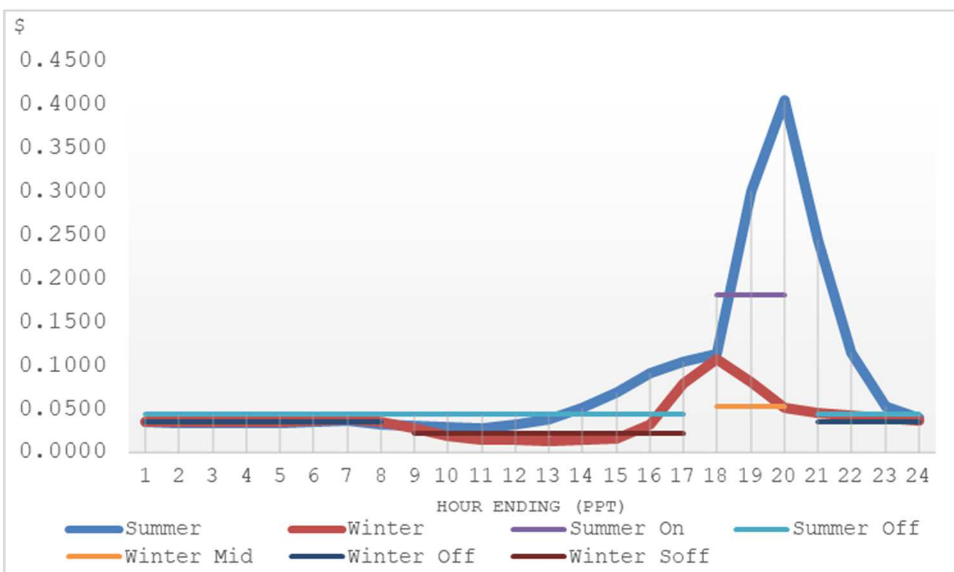


Figure D-2
Graphical Representation of Regression Analysis on Alternate TOU Periods Marginal Cost



The continuous lines show the seasonal average marginal costs and the step lines illustrate the estimates of the regression results. The errors or residuals consist in the differences between the two sets of lines. As demonstrated by the graphs, the lines in the current periods are a slightly better fit than the alternate periods.

IV. Regression Analysis Recommendations

The results of this analysis support the use of the current TOU periods adopted in the 2016 RDW. As noted in the 2016 RDW, the limitation of this test is that increasing the number of TOU periods will likely result in better ratios than scenarios with fewer periods.[5] Additional periods will also result in the regression model fitting the data better. Thus, there is a tradeoff between having well-designed TOU periods and simplicity.

V. Dead Band Tolerance Range Analysis

In Decision (D.)17-01-006, which resolved all issues in Rulemaking (R.)15-12-012 (TOU-OIR), the Commission directed each IOU to propose a "dead band tolerance range." The intent of this tolerance range is to provide a trigger mechanism for more frequent reviews of existing TOU periods than every other GRC. If data used in a GRC or RDW proceeding exceeds the tolerance range, then the utility would initiate a review and decide whether the TOU periods need to be revised.

In Advice 3581-E, SCE proposed to establish a dead band tolerance range based on the results of a (a) top-20 and top-100 highest-cost hour assessment and (b) lowest 20 and lowest 100 cost hour assessment. If the results showed that less than 75 percent of the top 20 and the top 100 highest cost hours fall within the current on-peak period, the dead band tolerance range is exceeded and a more frequent update to the TOU periods may be warranted. Similarly, if less than 75 percent of the lowest 20 and lowest 100 cost hours fall within the current off-peak (or super-off-peak) period, the band tolerance range is exceeded and a more frequent update to the TOU periods may be warranted.

Resolution E-4948 approved Advice 3581-E and directed SCE to use the top high-cost 100-hour criterion only and a trigger of 7.5 percent differential. A decline of at least 7.5 percent in the top 100 high-cost hours that fall within the summer peak and mid-peak period or a decline of at least 7.5 percent in the number of top 100 low-cost hours that fall within the winter super off peak period will be considered as breaching the dead band.

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[5] A.16-09-003, Exhibit SCE-1, p. 71.

Using the highest 100 hours ranked by the 2024 total marginal cost as put forward in Table D-5, SCE determined the following results:

Table D-5
Dead Band Analysis

		Summer On	Summer Mid	Summer Off	Winter Mid	Winter Super Off	Peak Periods
Top 100 Hours	Number of Hours	67	4	6	21	2	**92**
	% Captured	**67%**	**4%**	6%	**21%**	2%	**92%**

		Summer Off	Winter Mid	Winter Super Off	Low Periods
Top 100 Hours	Number of Hours	9	3	88	**97**
	% Captured	**9%**	3%	**88%**	**97%**

The results for the peak periods (*i.e.*, 4:00 to 9:00 p.m.) show that 92 percent of the top 100 hours are captured in the peak periods compared with 94 percent in the previous GRC filing, which is a 2% change. Similarly, within the top lowest cost 100 hours, 97% are included in the low-cost periods, again within the tolerance band. Thus, a further update is not warranted.

Attachment RII-5
Excerpt from SBUA Direct Testimony,
SDG&E Phase 2 GRC A.19-03-002

Q: Given the problems with demand charges for all but the most local costs, does SDG&E propose to phase them down or entirely phase them out?

A: No. SDG&E is charging the NCP demand rate for tariffs AL-TOU and TOU-M based on the customer's maximum 15-minute load at any time in the month, regardless of the state of load on the distribution system at that hour, because it is recovering unidentified demand costs that are incurred based on a customer's non-coincident power demand and not their energy consumption. Similarly, the seasonal on-peak demand charges are charged for the customer's maximum 15-minute load at any time in the defined peak period, even if that customer's maximum load occurs at a time of relatively low load on the feeder, substation, and system.

There are no such costs above the service drop for most customers.

In order to support its proposed subscription charge, SDG&E must pretend that there exist costs that are not related to load conditions on the distribution system but are somehow related to the individual customer's demand. Of course, the actual demand costs on the distribution system are related to the diversified load, not individual customers. Using TOU or CPP energy charges (or similar incentives) would more effectively send the proper price signals to customers.

Q: How should the Commission respond to SDG&E's reliance on demand charges?

A: The Commission should order SDG&E to reduce the NCP demand charges in the AL-TOU tariff and shift the revenue collection to TOU energy rates. The on-peak CP charge should be spread over the peak period energy (or average demand in the peak period). As I note below, the peak period should be shifted towards the evening.

C. TOU Periods

Q: What periods does SDG&E use for TOU pricing?

A: The time periods are shown in Table 3. The time periods are very similar throughout the year, expect that a longer super off-peak periods on the weekend and four extra super off-peak hours in March and April weekdays.

Table 3: SDG&E TOU Periods

Weekdays	Summer June–October	Winter November–February, May	March–April
On-Peak	4 PM – 9 PM	4 PM – 9 PM	4 PM – 9 PM
Off-Peak	6 AM – 4 PM 9 PM – midnight	6 AM – 4 PM 9 PM – midnight	6 AM – 10 AM 2 PM – 4 PM 9 PM – midnight
Super-Off-Peak	Midnight – 6 AM	Midnight – 6 AM	10 AM – 2 PM Midnight – 6 AM
Weekends and Holidays			
On-Peak	4 PM – 9 PM	4 PM – 9 PM	4 PM – 9 PM
Off-Peak	2 PM – 4 PM 9 PM – midnight	2 PM – 4 PM 9 PM – midnight	2 PM – 4 PM 9 PM – midnight
Super-Off-Peak	Midnight – 2 PM	Midnight – 2 PM	Midnight – 2 PM

Q: Did SDG&E select appropriate TOU periods?

A: Not entirely. SDG&E appears to have simply used the TOU periods adopted for SDG&E customers in Decision 17-08-030, which would have been based on a record that is now at least four years out of date.

The proposed peak period is 4–9 PM year-round, including both weekdays and weekends. That period appears to be too early.

The period with high market energy prices extends much later, to about 11 PM. Generation capacity costs, to maintain reliability locally and statewide, may also be driven by loads in a somewhat different daily pattern than the energy costs, but will also tend to be pushed later as solar generation reduces net load in the late afternoon.

Q: How does SDG&E justify continuing to use its existing TOU periods?

A: SDG&E presents load data in its Deadband Tolerance Analysis, as well as LOLE data. (SDG&E Revised Testimony, Chapter 6, pp. 11-14, and Workpapers 2 and 4)

Q: How do you review SDG&E's TOU periods?

A: I examine the load data that SDG&E provided in its Deadband Tolerance Analysis, locational marginal costs, LOLE as an indicator of hourly contribution to generation cost responsibility, and the time of peak loads for distribution feeders and substations.

1. Load Patterns

Q: How useful is the SDG&E load analysis?

A: Not very. The costs that SDG&E will be recovering from these rates are related to generation, transmission and distribution costs, none of which necessarily vary exclusively with customer load.

Nonetheless, the load data that SDG&E provides does not support retaining the existing TOU periods.

Q: What does SDG&E's Deadband Tolerance Analysis show about the appropriateness of the TOU periods?

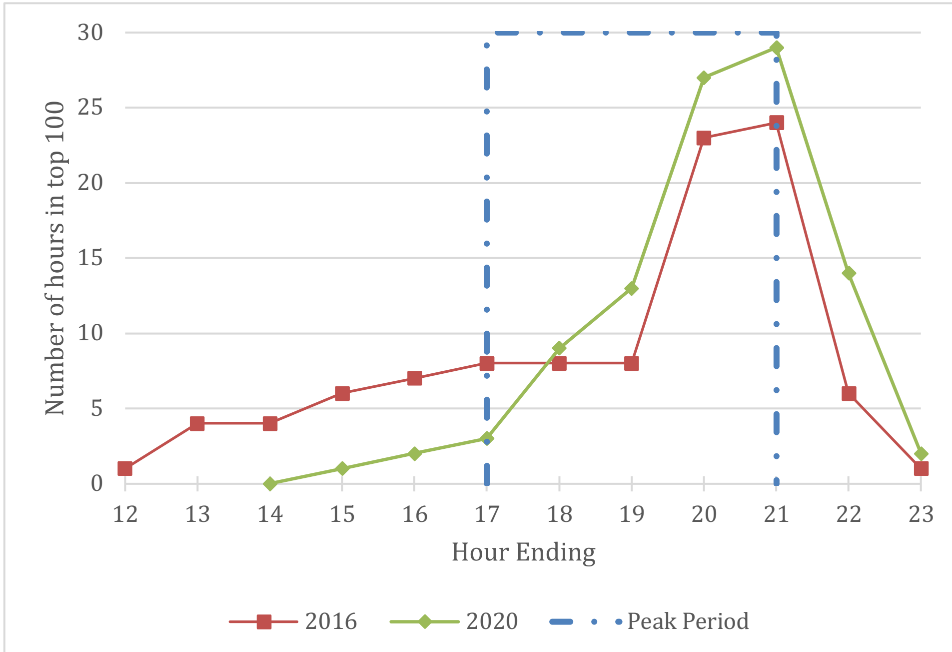
A: Since system load is a rough proxy for costs, at best, the value of this analysis is limited. I will discuss better measures, below.

Nonetheless, the Deadband Tolerance Analysis indicates that system load patterns have changed dramatically since 2016.

Q: What does SDG&E's Deadband Tolerance Analysis show about the timing of the 100 highest-load hours?

A: The peak loads have shifted later in the day. In 2016, the hours with the largest number of the highest 100 hours were the hours ending 5 PM through 9 PM. In 2020, SDG&E expects the third-highest number of top hours outside the peak period, in the hour ending 10 PM. These data are summarized in Figure 1 and Table 4.

Figure 1: Hourly Distribution of Top 100 Hours



In 2016, 30 of the top 100 hours were in the first peak hour, or earlier. In 2020, that had dropped four fifths, to 6% of the hours. In 2016, 7% of the top hours were after the peak period; in 2020, that is expected to more than double, to 16%. These shifts occurred over four years; by the end of the rates set in this proceeding, another two years will have elapsed and loads will likely have shifted even later.

Table 4: Hourly Distribution of Top 100 Hours

Hour	2016	2020
12	1	
13	4	
14	4	0
15	6	1
16	7	2
17	8	3
18	8	9
19	8	13
20	23	27
21	24	29
22	6	14
23	1	2

Based solely on load, the peak period should be shifted to 5 PM–10 PM, hours ending 17–22.

Q: What about SDG&E's review of the lowest hours and the super off-peak period?

A: SDG&E reports that 46% of the 100 bottom hours are in the super off-peak period, down from 87% in 2016. Extrapolating that change for another two years would bring the percentage of the lowest hours that fall into the super off-peak period down to about 26%.

In fact, only 15 of the 46 hours are in the super off-peak period, and those are entirely in the noon to 2 pm period in March and April. Table 5 shows the actual distribution of the lowest 100 hours on weekdays. (SDG&E Revised Testimony, Chapter 6, WP#2) The super off-peak period from midnight to 6 AM misses all the lowest hours, as does the 10 AM to noon hours in March and April.

Table 5: Distribution of Bottom 100 Hours on Weekdays, 2020

	Mar	Apr	May
11	-	-	-
12	-		
13	3	1	3
14	3	8	6
15	3	5	9
16	3	-	2

The results match a little better on weekends and holidays. Table 6 shows that distribution. Of the 54 lowest weekend and holiday hours, 31 fall in the super off-peak.

Table 6: Distribution of Bottom 100 Hours on Weekends and Holidays, 2020

	Mar	Apr	May	Jun
11				
12		3	4	
13	2	4	5	
14	2	4	6	1
15	2	4	5	2
16	2	3	4	

Based solely on the projection of the lowest 100 hourly load, the super off-peak period should be something like noon to 4 PM, March through May.

Q: Have you reviewed additional SDG&E load data?

A: Yes. I used the data in SDG&E's Chapter 6, WP#3 to produce Table 7 for weekdays and Table 8 for weekends. The highest-load hours are marked in red, the lowest in blue. The peak periods are in solid black boxes, and the super off-peak periods are in dashed boxes.

Table 7: Weekday Net Load for 2020

	1	2	3	4	5	6	7	8	9	10	11	12	Annual
1	1,602	1,541	1,296	1,216	1,206	1,333	1,555	1,687	1,725	1,509	1,476	1,651	1,483
2	1,460	1,387	1,198	1,115	1,111	1,215	1,435	1,556	1,606	1,421	1,349	1,483	1,361
3	1,386	1,321	1,142	1,072	1,068	1,165	1,378	1,494	1,537	1,370	1,258	1,387	1,298
4	1,338	1,277	1,115	1,045	1,049	1,152	1,351	1,459	1,486	1,340	1,206	1,328	1,262
5	1,314	1,250	1,120	1,069	1,063	1,179	1,364	1,473	1,483	1,335	1,175	1,288	1,259
6	1,334	1,264	1,209	1,147	1,026	1,084	1,337	1,525	1,563	1,418	1,190	1,305	1,283
7	1,443	1,363	1,248	937	714	776	1,049	1,315	1,476	1,457	1,251	1,408	1,203
8	1,509	1,243	841	503	410	543	816	962	1,038	1,016	972	1,398	938
9	1,074	744	361	174	205	364	642	720	745	614	444	987	589
10	606	361	48	-61	16	183	467	530	552	399	184	609	325
11	367	157	-133	-188	-114	65	344	431	468	313	64	397	181
12	265	52	-222	-274	-216	-8	294	401	439	270	32	323	113
13	214	-26	-285	-332	-253	-47	286	456	484	289	10	270	89
14	247	-41	-276	-299	-256	-18	361	562	650	409	74	318	144
15	431	69	-182	-173	-127	127	510	744	863	663	344	540	318
16	841	432	105	90	125	354	802	1,052	1,196	1,149	958	1,057	680
17	1,438	1,129	705	590	526	699	1,169	1,509	1,793	1,815	1,576	1,594	1,212
18	1,847	1,683	1,412	1,301	1,217	1,317	1,738	2,113	2,358	2,170	1,865	1,968	1,749
19	2,284	2,076	1,772	1,680	1,672	1,791	2,141	2,416	2,482	2,350	2,224	2,355	2,104
20	2,369	2,282	2,068	1,926	1,855	1,926	2,208	2,465	2,580	2,408	2,234	2,400	2,227
21	2,322	2,261	2,057	1,987	1,990	2,061	2,307	2,510	2,543	2,328	2,158	2,359	2,240
22	2,243	2,182	1,960	1,884	1,892	2,014	2,271	2,413	2,407	2,184	2,058	2,288	2,150
23	2,116	2,047	1,733	1,617	1,621	1,779	2,045	2,178	2,176	1,924	1,914	2,180	1,944
24	1,835	1,774	1,484	1,363	1,348	1,503	1,758	1,904	1,919	1,665	1,664	1,916	1,678

For weekdays, the highest net loads are found in hours ending 18 to 23 or 24, starting one hour later than SDG&E's peak period and ending two to three hours later. The lowest-load hours are those ending 8 to 16, completely missing SDG&E's early-morning super off-peak period but including the March–April midday super off-peak.

Table 8: Weekend Net Load for 2020

	1	2	3	4	5	6	7	8	9	10	11	12	Annual
1	1,541	1,492	1,233	1,171	1,137	1,216	1,403	1,492	1,559	1,405	1,426	1,621	1,391
2	1,445	1,393	1,189	1,123	1,081	1,149	1,332	1,429	1,498	1,365	1,340	1,497	1,320
3	1,370	1,318	1,133	1,071	1,029	1,099	1,288	1,380	1,438	1,319	1,247	1,392	1,257
4	1,318	1,272	1,108	1,037	1,008	1,089	1,270	1,359	1,395	1,288	1,201	1,338	1,224
5	1,297	1,245	1,115	1,045	1,012	1,112	1,284	1,373	1,400	1,283	1,173	1,304	1,220
6	1,307	1,245	1,196	1,065	926	1,005	1,239	1,402	1,471	1,336	1,173	1,311	1,223
7	1,360	1,278	1,184	749	522	657	910	1,133	1,355	1,286	1,181	1,371	1,082
8	1,288	1,004	702	260	161	377	618	735	896	818	808	1,243	743
9	813	451	232	-58	-49	188	431	486	607	419	245	789	380
10	408	126	-58	-279	-245	-1	245	289	399	206	-15	468	129
11	213	-37	-223	-400	-375	-145	101	155	284	103	-130	284	-14
12	126	-127	-321	-494	-481	-241	34	83	222	45	-162	223	-91
13	80	-201	-388	-563	-536	-304	15	95	235	37	-183	175	-128
14	118	-217	-396	-556	-573	-308	58	167	356	130	-130	221	-94
15	295	-127	-322	-449	-468	-192	175	319	550	357	118	418	56
16	707	225	-65	-209	-257	-2	415	572	844	808	730	927	391
17	1,271	899	542	319	153	351	780	1,031	1,458	1,487	1,328	1,437	921
18	1,663	1,454	1,254	1,053	861	979	1,348	1,642	2,033	1,869	1,656	1,813	1,469
19	2,106	1,874	1,608	1,472	1,357	1,482	1,773	1,992	2,201	2,113	2,067	2,224	1,856
20	2,208	2,115	1,926	1,753	1,589	1,660	1,872	2,076	2,330	2,178	2,092	2,265	2,005
21	2,159	2,103	1,963	1,867	1,805	1,885	2,054	2,218	2,339	2,142	2,027	2,219	2,065
22	2,116	2,066	1,835	1,743	1,703	1,807	1,999	2,109	2,181	1,979	1,965	2,193	1,975
23	1,965	1,919	1,603	1,522	1,480	1,585	1,808	1,916	1,974	1,756	1,799	2,069	1,783
24	1,732	1,691	1,398	1,313	1,264	1,364	1,563	1,675	1,731	1,538	1,595	1,849	1,559

For weekends, the highest net loads are found in the same hours as on weekdays. The lowest-load hours are those ending 8 to 17, covering about half of SDG&E's weekend super off-peak period but overlapping with the first hour of the SDG&E peak period.

SDG&E's TOU periods do not reflect the patterns in net load.

2. Generation Capacity Costs

Q: What information is available from SDG&E's LOLE analysis?

A: Table 9 shows the distribution of LOLE by hour for each day of the week, for the SD GRA—the results for the SD Subarea are similar. While the weekend LOLEs are lower than the weekday LOLEs, the high-LOLE hours are similar. To make the data easier to scan, I converted SDG&E's LOLE values to fractions of the total, and rounded values under 0.0005 to zero. The box identifies SDG&E's peak period.

Table 9: LOLE Distribution by Weekday and Hour

Hour	Mon	Tues	Weds	Thurs	Fri	Sat	Sun	Total
1	0.001	0.001	0.002	0.001	0.001	-	-	0.006
2	-	0.001	-	-	-	-	-	0.001
3	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-
7	0.001	0.001	0.001	0.001	0.001	-	-	0.005
8	0.001	0.001	0.001	0.001	0.001	-	-	0.005
9	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.007
10	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-
14	-	-	0.001	-	-	-	-	0.001
15	0.001	0.001	0.001	0.001	0.001	-	-	0.005
16	0.002	0.002	0.003	0.002	0.001	-	-	0.010
17	*0.005*	*0.004*	*0.005*	*0.004*	*0.003*	*-*	*-*	0.021
18	*0.014*	*0.013*	*0.014*	*0.013*	*0.011*	*0.003*	*0.002*	0.070
19	*0.031*	*0.031*	*0.031*	*0.030*	*0.026*	*0.012*	*0.013*	0.174
20	*0.040*	*0.041*	*0.040*	*0.038*	*0.034*	*0.019*	*0.019*	0.231
21	*0.036*	*0.037*	*0.036*	*0.035*	*0.031*	*0.018*	*0.019*	0.212
22	0.027	0.027	0.026	0.025	0.022	0.011	0.012	0.150
23	0.013	0.013	0.013	0.012	0.010	0.004	0.004	0.069
24	0.004	0.003	0.003	0.004	0.003	0.001	0.001	0.019
Daily Total	0.180	0.179	0.181	0.170	0.149	0.070	0.072	

Table 9 shows that the LOLP is concentrated in the hours ending 19 to 22, with lower, but roughly equal LOLE in the hours ending 18 and 23.

Table 10 shows similar hourly patterns across the months, but also indicates that the period contributing to reliability issues runs from July through January or February. Again, the solid box identifies SDG&E's peak hours, while the dashed boxes indicate SDG&E's weekday super off-peak hours.

Table 10: LOLE Distribution by Month and Hour

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	-	-	-	-	-	-	0.001	0.003	0.003	-	-	-
2	-	-	-	-	-	-	-	0.001	0.001	-	-	-
3	-	-	-	-	-	-	-	-	0.001	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	0.001	0.001	-	-	-
7	-	-	-	-	-	-	-	0.003	0.003	0.001	-	-
8	-	-	-	-	-	-	-	0.002	0.003	0.001	-	-
9	-	-	0.001	0.001	0.001	-	-	0.001	0.001	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	0.001	-	-	-
14	-	-	-	-	-	-	-	0.001	0.001	-	-	-
15	-	-	-	-	-	-	-	0.002	0.002	-	-	-
16	-	-	-	-	-	-	0.001	0.004	0.005	0.001	-	-
17	-	-	-	-	-	-	0.002	0.007	0.008	0.003	0.001	-
18	0.002	0.001	-	-	-	0.001	0.007	0.014	0.019	0.012	0.005	0.007
19	0.016	0.008	0.003	0.001	0.002	0.005	0.016	0.027	0.032	0.023	0.016	0.024
20	0.020	0.016	0.013	0.007	0.006	0.011	0.023	0.033	0.037	0.025	0.015	0.025
21	0.015	0.012	0.010	0.007	0.009	0.014	0.026	0.033	0.033	0.020	0.012	0.020
22	0.010	0.008	0.005	0.003	0.005	0.011	0.022	0.027	0.024	0.012	0.007	0.016
23	0.005	0.003	0.001	-	0.001	0.004	0.011	0.016	0.013	0.004	0.002	0.009
24	-	-	-	-	-	0.001	0.003	0.007	0.006	0.001	-	0.001
Monthly Total	0.069	0.048	0.034	0.019	0.024	0.048	0.112	0.183	0.195	0.105	0.060	0.104

June LOLE is lower than October and about equal to February. Pursuant to California policy to reduce natural gas use and carbon emissions, winter loads are likely to grow. Hence, using the same on-peak period for all months is reasonable, although April and May LOLEs are lower than other months.

The peak LOLE hours are hours ending 19 to 22, which account for 77% of annual LOLE. Hours ending 18 and 23 each account for 7%, hours 17 and 24 about 2% each. The remaining sixteen hours (hours 1 through 16) account for less than 5% of LOLE, mostly in hours 1, 7–9 and 16.

Q: How do your results differ from those reported by SDG&E?

A: SDG&E's result is incorrect. As shown in Figure 2, reproducing Chart BAM-3, SDG&E reports that the maximum LOLE values are in the hours ending 20, 21, and 22, with hours ending 19 and 23 essentially tied. The SDG&E chart shows the LOLE values peaking even later than they actually do.

Figure 2: SDG&E's Reported Distribution of LOLE for the San Diego Local Capacity Areas by Hour

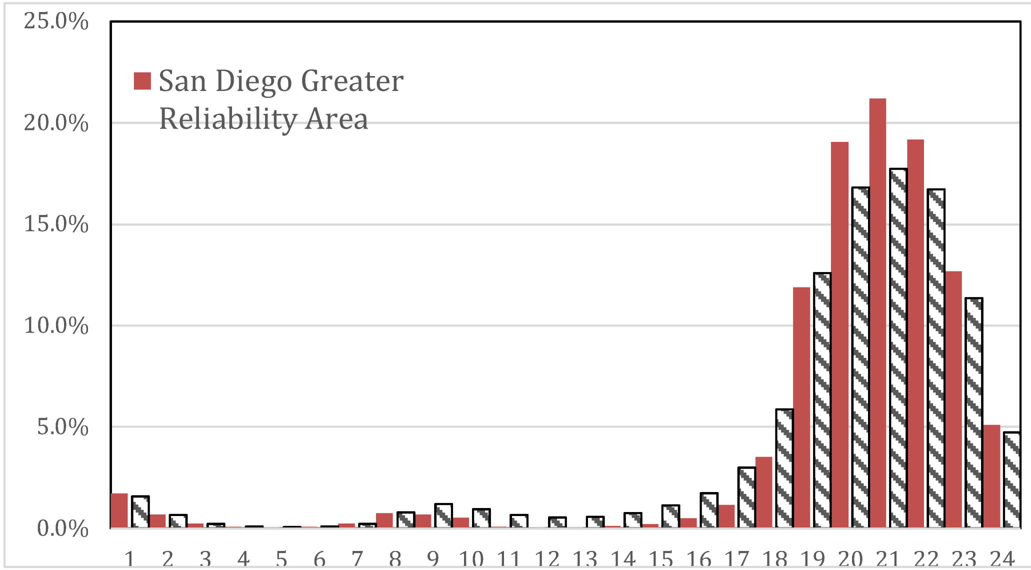


Figure 2 is supposed to be based on the same data that I report in Table 9 and Table 10, but there appears to be some problem with SDG&E's pivot tables.

Q: What are in implications of the LOLE data for the super off-peak period?

A: The LOLE is low (under 2.5% of the annual total) in most hours, other than hours ending 18–23, so LOLE values may not be particularly important in setting the super off-peak period. Nonetheless, it is interesting to note that the SDG&E super off-peak hours include 1.5% of the LOLE, mostly in hours 1 and 2 in July to September. A super off-peak period of hours ending 3–5 and 10–13 would sweep up only about 0.6% of the annual LOLE over seven hours. Even extending the super off-peak to hours 2–6 and 10–14 would cover only 1.3% of LOLE over ten hours.

Summer (specifically August and September) contributes most of the LOLE to those super off-peak hours in hours 2, 6, and 14. If any special months are called out for different super off-peak hours based on LOLE data, it would be August and September, not March and April.

3. Locational Marginal Prices

Q: How well do SDG&E's TOU periods match with locational marginal prices?

A: The TOU periods do not match well to SDG&E's LMPs.

Q: What mismatches have you identified?

A: First, the designated peak hours do not appear to match well with locational marginal price variation over the day or week. Table 11: Relative Weekday LMP Patterns by Month

shows the LMP for each weekday hour (e.g., the average price in the 9 AM hour, across all weekdays) in each month, normalized to the highest hourly price. I used 2019 prices at the Urban 6 substation for this illustration.

Cells in red are the highest hours in each month, while cells in blue are the lowest. I have marked the on-peak hours with a solid box and the super off-peak hours with a dashed box.

Table 11: Relative Weekday LMP Patterns by Month

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
1	0.54	0.54	0.48	0.34	0.35	0.33	0.37	0.39	0.40	0.39	0.35	0.48	0.42
2	0.52	0.52	0.45	0.31	0.30	0.30	0.35	0.37	0.38	0.37	0.34	0.46	0.39
3	0.51	0.51	0.43	0.29	0.26	0.29	0.33	0.36	0.36	0.36	0.33	0.45	0.37
4	0.51	0.51	0.43	0.29	0.27	0.28	0.32	0.35	0.36	0.36	0.33	0.46	0.37
5	0.54	0.55	0.48	0.33	0.34	0.31	0.34	0.36	0.37	0.38	0.36	0.48	0.40
6	0.60	0.70	0.63	0.49	0.53	0.38	0.41	0.42	0.44	0.45	0.41	0.53	0.50
7	0.76	0.89	0.82	0.64	0.65	0.42	0.42	0.47	0.54	0.58	0.48	0.67	0.61
8	0.79	0.78	0.73	0.61	0.62	0.37	0.39	0.43	0.50	0.53	0.38	0.57	0.56
9	0.63	0.56	0.51	0.43	0.53	0.39	0.32	0.36	0.39	0.36	0.32	0.26	0.42
10	0.58	0.45	0.35	0.35	0.47	0.37	0.37	0.39	0.36	0.25	0.26	0.20	0.37
11	0.48	0.40	0.27	0.29	0.45	0.42	0.39	0.45	0.37	0.22	0.23	0.14	0.34
12	0.48	0.37	0.22	0.26	0.39	0.43	0.42	0.47	0.44	0.21	0.22	0.13	0.34
13	0.42	0.33	0.19	0.27	0.37	0.44	0.45	0.52	0.52	0.24	0.23	0.19	0.35
14	0.43	0.33	0.17	0.25	0.31	0.40	0.48	0.64	0.52	0.26	0.26	0.18	0.35
15	0.45	0.35	0.22	0.24	0.30	0.50	0.50	0.65	0.60	0.28	0.30	0.28	0.39
16	0.54	0.45	0.28	0.27	0.33	0.49	0.80	0.72	0.62	0.34	0.40	0.44	0.47
17	0.72	0.64	0.40	0.33	0.29	0.50	0.59	0.61	0.61	0.41	0.61	0.65	0.53
18	1.00	0.84	0.58	0.45	0.39	0.49	0.62	0.67	0.73	0.65	1.00	1.00	0.70
19	0.95	1.00	0.83	0.67	0.61	0.77	0.72	0.87	1.00	1.00	0.68	0.88	0.83
20	0.85	0.90	1.00	1.00	0.96	1.00	1.00	1.00	0.98	0.77	0.55	0.78	0.90
21	0.76	0.85	0.85	0.85	1.00	0.81	0.72	0.68	0.66	0.58	0.48	0.66	0.74
22	0.67	0.78	0.75	0.67	0.75	0.54	0.55	0.55	0.56	0.51	0.44	0.61	0.61
23	0.61	0.66	0.62	0.50	0.55	0.41	0.46	0.47	0.48	0.47	0.40	0.56	0.52
24	0.56	0.60	0.56	0.42	0.42	0.34	0.40	0.42	0.44	0.42	0.38	0.53	0.46

Table 12: Relative Weekend LMP Patterns by Month

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ave
1	0.68	0.72	0.55	0.49	0.43	0.43	0.47	0.51	0.57	0.56	0.50	0.58	0.54
2	0.65	0.68	0.52	0.44	0.37	0.38	0.45	0.50	0.56	0.54	0.48	0.56	0.51
3	0.63	0.64	0.48	0.39	0.32	0.36	0.43	0.48	0.54	0.53	0.46	0.54	0.48
4	0.64	0.61	0.47	0.38	0.31	0.35	0.42	0.47	0.54	0.52	0.47	0.54	0.48
5	0.66	0.65	0.49	0.43	0.36	0.36	0.42	0.47	0.53	0.53	0.48	0.54	0.49
6	0.69	0.71	0.56	0.48	0.43	0.42	0.44	0.50	0.57	0.57	0.51	0.57	0.54
7	0.73	0.78	0.63	0.51	0.37	0.38	0.41	0.51	0.58	0.62	0.52	0.59	0.55
8	0.69	0.67	0.55	0.36	0.19	0.22	0.36	0.42	0.53	0.59	0.45	0.59	0.47
9	0.62	0.87	0.41	0.13	0.14	0.11	0.26	0.26	0.38	0.48	0.36	0.40	0.37
10	0.56	0.65	0.27	0.02	0.11	0.10	0.31	0.27	0.30	0.33	0.27	0.31	0.29
11	0.49	0.44	0.19	0.00	0.07	0.09	0.33	0.32	0.31	0.28	0.21	0.25	0.25
12	0.43	0.27	0.13	<0	0.03	0.11	0.39	0.37	0.36	0.31	0.24	0.18	0.23
13	0.40	0.26	0.10	<0	0.02	0.15	0.50	0.43	0.43	0.31	0.22	0.27	0.26
14	0.43	0.34	0.10	<0	0.02	0.21	0.62	0.55	0.48	0.39	0.27	0.30	0.31
15	0.50	0.55	0.11	<0	0.02	0.28	0.48	0.61	0.65	0.42	0.35	0.43	0.36
16	0.62	0.54	0.16	0.00	0.04	0.35	0.56	0.80	0.58	0.41	0.47	0.59	0.43
17	0.74	0.88	0.28	0.05	0.05	0.37	0.58	0.58	0.64	0.49	0.64	0.72	0.50
18	0.95	0.90	0.55	0.29	0.21	0.45	0.63	0.64	0.81	0.73	1.00	1.00	0.68
19	1.00	1.00	0.84	0.63	0.49	0.65	0.72	0.85	0.99	1.00	0.76	0.90	0.82
20	0.90	0.93	1.00	1.00	0.80	1.00	1.00	1.00	1.00	0.88	0.68	0.81	0.92
21	0.82	0.89	0.88	1.00	1.00	0.97	0.80	0.78	0.81	0.75	0.62	0.69	0.83
22	0.75	0.84	0.79	0.79	0.72	0.63	0.66	0.65	0.70	0.68	0.55	0.64	0.70
23	0.71	0.76	0.71	0.58	0.51	0.48	0.54	0.56	0.63	0.62	0.53	0.62	0.60
24	0.66	0.70	0.58	0.50	0.42	0.41	0.48	0.52	0.57	0.56	0.49	0.58	0.54

While the monthly price patterns vary, the general pattern is an on-peak period (relative LMP > 0.5) in the hours ending 18 to 22 (or 23), with additional peak hours in the non-summer hours ending 6 AM to 8 AM and perhaps in the summer ending at 4 and 5 PM. Based on these LMPs, the super off-peak (relative price < 0.4) should be approximately midnight to 5 AM in the summer weekdays, 7 AM to 2 PM summer weekends, and 10 AM to 4 PM in the non-summer months.

4. *Distribution Costs*

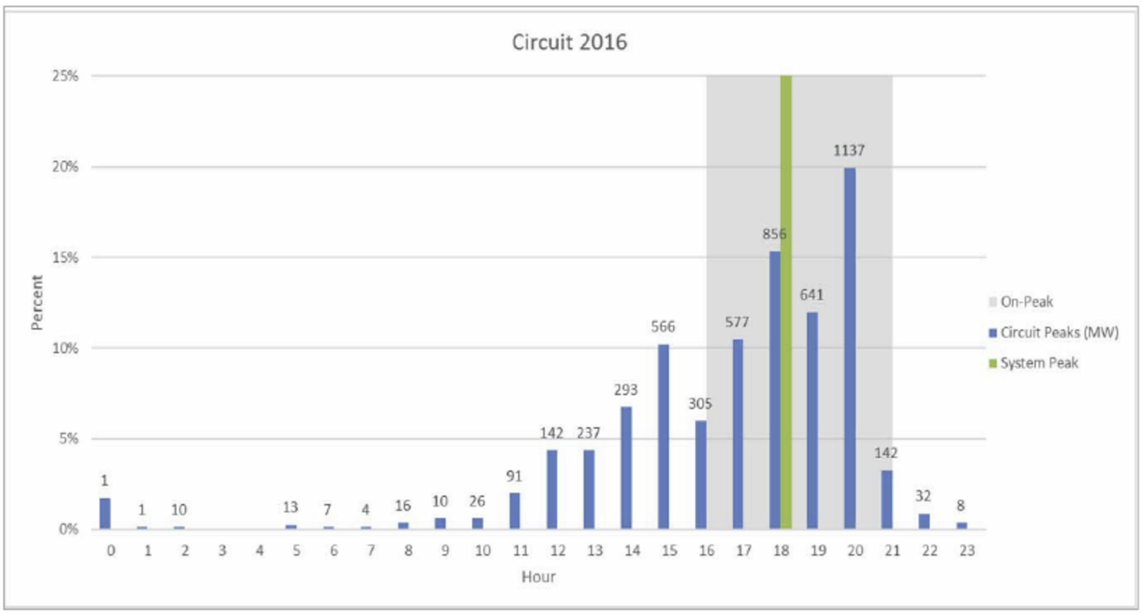
Q: What information do you have on the times with the greatest contribution of load in various hours to SDG&E distribution costs?

A: Not much, unfortunately. In the Demand Charge Workshop Report (Attachment D, p. 5), SDG&E reported that about 33% to 42% of circuits hit their peak loads outside the 4 PM to 9 PM period, as reproduced in Table 13 and Figure 3.

Table 13: Count of SDG&E Feeders Peaking in its Legacy Peak Period

	Circuit - % Peaking	
	On-peak (4pm - 9 pm)	All Other Hours
2014	58.2%	41.8%
2015	59.1%	40.9%
2016	67.0%	33.0%

Figure 3: Number of SDG&E Circuit Peaks by Hour, 2016



SDG&E has not provided even this minimal level of detail for the percentage of peak feeder loads in MW or MVA that occur in each hour, nor any data on substation peaks or subtransmission peaks, nor any data from 2017 through 2019.

Interestingly, SDG&E does not differentiate the distribution rate by time period. The TOU-A, TOU-A3 and TOU-M rates recover all distribution costs through a single non-time-differentiated flat energy rate. In contrast, the AL-TOU uses a combination of a small flat energy rate and larger on-peak and non-coincident demand charges. None of these rate components match well the period that drives the number of feeder peaks.

The scarcity of information related to the hours in which demand drives distribution costs limits my ability to address the contribution of distribution costs to appropriate TOU purposes. The Commission should instruct SDG&E to investigate this issue further.

Q: Please summarize your recommendations with respect to peak periods.

A: Based upon my analysis to date, I recommend that the peak hours be set as 5 PM to 10 PM throughout the year, if the Commission believes that a simple TOU pattern will improve customer response. The lowest-cost hours vary widely through the year; I suggest that the super off-peak be set at midnight to 5 AM in the summer weekdays, 7 AM to 2 PM summer weekends, and 10 AM to 4 PM in the non-summer months.

Q: Does this conclude your testimony?

A: Yes.