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 to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021	)))))	**Rulemaking 20-11-003**

REPLY TESTIMONY OF

JOHN D. WILSON

ON BEHALF OF

THE SMALL BUSINESS UTILITY ADVOCATE

Resource Insight, Inc.

JANUARY 11, 2021

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I. Introduction

Q: Are you the same John D. Wilson who filed direct testimony in this proceeding on behalf of Small Business Utility Advocates (SBUA)?

A: Yes.

Q: What is the scope of your reply testimony?

A: My direct testimony primarily addressed Issues 2(b) Critical Peak Pricing (CPP) and 2(h) Other (with respect to time-of-use [TOU] periods). My reply testimony addresses these issues as well as responding to testimony related to Issues 2(a) Flex Alert paid media and social media, 2(c) the emergency load reduction pilot, 2(d) modifications to reliability demand response programs, and 2(e) modification to proxy demand responses.

Q: What issues do you address?

A: My reply testimony addresses the same issues as my direct testimony: 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. My reply testimony also addresses marketing for Flex Alerts, changes to the Base Interruptible Program, and the frequency of demand response program call rates.

Q: What do you recommend?

A: Below, I summarize my recommendations from my direct and reply testimonies. Modifications made by my reply testimony are underlined. 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 investor-owned utilities (IOUs) to evaluate CPP program impacts in 2021 and 2022 including a study of whether the various communication programs are effectively influencing customer behavior;
- 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, potentially including allowing both seasonal and full-year 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. Specifically, the Commission should direct coordination with vendors responsible for TOU and any other rate-related ME&O activities.
- As soon as possible (which may not be in this proceeding), the Commission should allow customers on distributed energy resource

tariffs to enroll in CPP; this expansion of CPP 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.
- The Commission should ensure that any emergency load reduction pilots (ELRPs) adequately provide for participation by small businesses, such as those that may wish to close business early during ELRP events.
- The Commission should advise the IOUs and CAISO as to its views on the order and primary basis for activating the various load management programs to address statewide reliability concerns.

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

Q: What is the current level of impact from CPP and TOU programs?

A: It is very difficult to form a clear understanding of the peak load impacts achieved by CPP and TOU pricing signals. In this proceeding's necessarily expedited timeframe, I have been able to locate an incomplete record of load impact evaluations, including a 2019 Statewide Non-Residential CPP Load

Impact Evaluation[1] and SDG&E's 2019 CPP and TOU Load Impact Evaluation.[2,3] Unfortunately, the available studies lack comprehensive analysis and recommendations for improving the pricing programs.

Residential customers may be more responsive to CPP and TOU pricing signals than non-residential customers. The statewide study found that CPP events had a total load impact of less than 1% for non-residential customers, with most of the effects concentrated among large customers.[4]

The studies suggest a much higher impact for residential customers. SDG&E's study reports a measured 15% load reduction for TOU customers in the TOU peak period, and an estimated 18% impact for CPP customers during CPP events.[5] SDG&E's CPP rate customers showed a lower reduction (just 6%) average over the peak TOU periods.[6]

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[1] PG&E, Direct Testimony, Ch. 3, p. 9, FN 32; SCE, Direct Testimony, p. 10, line 14; and SDG&E, Opening Testimony on Demand Response Issues, p. 9, lines 19-20.

[2] Christensen Associates Energy Consulting, *2019 Load Impact Evaluation of San Diego Gas and Electric's Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates,* CALMAC Study ID SDG0321(April 1, 2020).

[3] PG&E's makes monthly reports available, but they provide only gross ex ante and ex post estimated impacts, and are caveated by noting that the estimates will vary from the annual filing, cost effectiveness analyses, and other purposes. PG&E, *Monthly Report On Interruptible Load and Demand Response Programs for November 2020* (December 21, 2020), p. 3. SCE provided unsourced data indicating relatively low CPP impacts for its non-residential customers. SCE, Reply Comments, p. 6.

[4] Applied Energy Group, p. 80.

[5] Christensen Associates, pp. 10, 50. Because there were no CPP events during the study period, the analysis was unable to study actual load reduction during CPP events.

[6] Christensen Associates, p. 11. This result may be due to the reduced incentives during non-event peak hours. In terms of reducing the risk of inadequate capacity in 2021 and 2022, the non-CPP peak hours are not very important.

Q: What did the IOUs recommend to increase effectiveness and participation in CPP and other demand response programs?

A: PG&E is the only IOU to offer specific program change improvements in its testimony. PG&E recommended that the Commission authorize it to:

- Shift the CPP event notification later in the day.[7]
- Remove the default participation requirement for commercial CPP programs, limiting participation to customers who opt into the program.[8]
- Allow customers with distributed energy resources to participate in commercial CPP programs, but only after the next Phase 2 General Rate Case.[9]

With respect to additional budget requirements, PG&E's budget increase would be focused primarily on motivating CPP participation while explaining to customers that its commercial CPP program would remain opt-in, and would primarily impact summer 2022.[10]

Q: What are your responses to PG&E's recommendations?

A: I am generally supportive of the direction PG&E suggests for its CPP program, but there are issues with each of its recommendations.

PG&E's proposal to shift CPP notification to later in the previous day should to be evaluated by the Commission in the context of providing better structure to the various load management programs. I will discuss this topic later in my testimony.

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[7] PG&E, Direct Testimony, Chapter 2, p. 1, line 24 – p. 2, line 2.

[8] PG&E, Direct Testimony, Chapter 2, p. 2, lines 3-8.

[9] PG&E, Direct Testimony, Chapter 2, p. 6, line 33 – p. 7, line 5.

[10] PG&E, Direct Testimony, Chapter 2, p. 2, lines 20-23, p. 3, lines 15-20.

I agree that CPP programs perform better, and cause less unexpected bill volatility, when operated as opt-in programs. Small business customers would prefer to have options, including a standard TOU rate, a TOU rate with greater peak differentiation, and a CPP rate. A standard TOU rate should be the default, since many small business customers will not have the capability to respond to CPP rates. Removing the default requirement should be accompanied by a more robust marketing, education and outreach (ME&O) strategy, as discussed in my direct testimony and further below.

As noted in my direct testimony, I am supportive of PG&E's third suggestion, to allow customers with renewable generation to participate in CPP. PG&E's proposed timing would delay expansion of eligibility to 2026, which would be irrelevant to the current proceeding and the goal of reducing peak loads in 2021 and 2022. The Commission should consider any feasible options for revising existing tariffs more expeditiously.

Q: What did other parties recommend to increase effectiveness and participation in CPP and other demand response programs?

A: The Public Advocates Office (Cal Advocates) argued that the TOU and CPP rates should be focused on residential programs because the peak net-load period is after the time that many businesses close, and because the August 2020 emergency event was driven by increases in residential load due to stay-at-home orders.[11] I do not agree with Cal Advocates on this point. First, many small businesses (e.g., recreation, entertainment, retail and dining) are open during the peak net-load period. Increasing participation should be refined to target relevant businesses, not disregard them. (Businesses that are closing

[11] Cal Advocates, Opening Testimony, Ch. 1, p. 6, lines 3-10.

could also be encouraged to take extra steps to reduce non-business-hours load during CPP events compared to load on typical days.) Second, the data suggest that better communication strategies can unleash more load-shifting potential from small and medium businesses.[12]

Q: Did any parties specifically discuss leveraging behavioral demand response (BDR) programs to improve the effectiveness of CPP programs?

A: No. However, PG&E did discuss continuing its "enhanced event season support" to its commercial customers. If its proposal to shift to an opt-in model is approved, PG&E intends to increase the effectiveness of its commercial CPP program by emphasizing the role of choice, as "customer research found the perception and availability of customer choice increased customer acceptance" and "high potential customers' average kilowatt (kw) savings on event days doubled after targeted messaging commenced."[13]

Q: Did any parties discuss the relationship between Flex Alerts and pricing signals to customers?

A: Only with respect to demand response programs; they did not discuss the relationship of Flex Alerts to CPP programs or TOU rates. Some parties argued that Flex Alerts should remain distinct from demand response programs to avoid customer confusion.[14] TURN suggested a link between Flex Alerts and

[12] It is worth noting that the evaluations discussed above included consideration of program impacts in the mid-afternoon since some CPP programs had not yet shifted to the peak net load period when evaluated.

[13] PG&E, Direct Testimony, Ch. 2, p. 4, lines 3-9, p. 5, lines 3-18.

[14] SCE, Direct Testimony, p. 46, lines 18-23. SDG&E, Opening Testimony on Flex Alert and CPP Issues, p. 4, lines 20-24.

the proposed Emergency Load Reduction Programs (ELRP).[15] The relationship between Flex Alerts communications and the Commission's TOU pricing policies was scarcely mentioned.

Q: Do you have any response to the recommendations related to Flex Alerts?

A: Yes. PG&E provided an extensive discussion of the advantages of using its own media agency, rather than options such as amending existing statewide ME&O contracts.[16]

If the Commission adopts PG&E's recommendation to coordinate, rather than centralize, planning and administration of Flex Alerts, the coordination should include other relevant communication programs. Accordingly, the Commission should direct that the coordination between CAISO, the IOUs, and other parties should include all vendors responsible for ME&O activities for TOU and any other rate programs, and that those vendors should be directed to make a reasonable attempt to coordinate to maximize load reduction impacts.

I am not aware that any party has provided evidence demonstrating the effectiveness of Flex Alerts, and one party relied on data from 2013 to suggest that Flex Alerts may not have useful impacts.[17] Due to the lack of readily available evidence to support additional funding from ratepayers for Flex Alerts, I simply encourage the Commission to consider whether there are more cost-effective methods to leverage existing load reduction programs with conservation messages.

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[15] TURN, Prepared Direct Testimony, p. 19, line 22 – p. 20, line 6.

[16] PG&E, Direct Testimony, Chapter 1, pp. 1-4. SCE provided a less detailed discussion of how Flex Alerts should be coordinated. SCE, Direct Testimony, p. 45, line 24 – p. 46, line 2.

[17] CEJA, Prepared Opening Testimony, p. 7, lines 5-7.

Q: Do you have any updates to your recommendations for non-binding CPP program goals and evaluations?

A: Yes. In my prior testimony, I recommended non-binding CPP program goals and evaluation of CPP program impacts in 2021 and 2022. I would like to elaborate on those recommendations.

My review of the utilities' routine evaluation of their demand response programs, including dynamic pricing, suggests that the evaluation efforts are not integrated into a common framework in a manner that leads to coordinated statewide review. While the statewide non-residential study did recommend that the IOUs investigate the experiences of small and medium participants, I do not see any indication in the IOUs' testimonies that suggests the recommendation is being acted on.

In order to drive the utilities to make more effective use of the pricing signals from CPP programs, I recommended a non-binding CPP program goal, such as achieving a 5% reduction in participant load per event. The reduction for CPP events should be measured relative to the TOU impact, so that CPP customers reduce load by at least 5% more than similarly situated TOU-only customers.

The 2021 and 2022 CPP program impact evaluations should not only include load impact evaluations, but should also study whether various utility-related communications are effectively influencing customer behavior. First, the studies should simply measure which communications customers are paying attention to. For example, the statewide non-residential study found that SCE sent notifications to just over half of small and medium business customers, but it did not measure customer awareness directly.[18] Second, the

[18] Applied Energy Group, p. 81.

studies should determine whether voluntary conservation messages (Flex Alerts), DR program triggers, CPP event notifications, TOU educational materials, and any other communications are mutually reinforcing, redundant, or potentially confusing. Feedback from these studies should be relayed immediately to all parties involved in customer communications related to demand-side management.

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

Q: Do other parties' prefiled testimony support your recommendations with respect to the number of CPP events and event triggers?

A: Yes. I recommended 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. I also recommended that the Commission give the IOUs flexibility to adapt their methods for triggering CPP events.

- PG&E is not opposed to eliminating the limits, and recommends using CAISO or state alerts as the main trigger for CPP events.[19]
- SCE recommends maintaining a maximum number of events.[20] SCE's testimony did not discuss whether its CPP program should continue to require exactly 12 events per year, and if so why.[21]

[19] PG&E, Direct Testimony, Chapter 2, p. 1, lines 17-23.

[20] SCE, Direct Testimony, p. 35, lines 15-21.

[21] Elsewhere in its testimony, SCE proposes replacing the requirement for a minimum of Summer Discount Plan (SDP) event dispatch hours with an annual target. My recommendation for increasing CPP event limit flexibility is very similar to SCE's recommendation for SDP event dispatch hours. SCE, Direct Testimony, p. 21, lines 18-25.

- SDG&E does not support removing the maximum number of events. In various years, SDG&E has called between zero and nine events, well below its maximum of 18 events, and SDG&E expresses concern about the bill effects for customers in a year with many events.[22]

Although there are good reasons not to increase the *expected number* of annual CPP events, very little of the submitted testimony appears to justify a need for minimum and maximum CPP event limits or SCE's exact 12 CPP event per year requirement.[23] SEIA did state that there needs to be a "reasonable limit on the number of event days" in order to reassure customers that the number of CPP events might be large and disruptive.[24] Even in the absence of regulatory limits on CPP events, the IOUs can provide guidance or their own policy statements. The utilities can abide by their own reasonable target or limit, as has been SDG&E's effective practice in remaining well below its 18 event limit. Regulatory limits could hinder a reasonable decision to call an unusually high number of CPP events in extraordinary circumstances, and regulatory limits that are well in excess of actual practice provide no useful information to customers.

Furthermore, none of the testimony identified any technical obstacle to removing the event limits or allowing flexibility with respect to event triggers. SEIA's testimony does address an issue I discussed in my direct testimony, which is the need for an estimate of the number of events for purposes of rate

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[22] SDG&E, Opening Testimony on Flex Alert and CPP Issues, p. 8, lines 4-12.

[23] SCE's program requirement to call exactly 12 events per year might be contributing to its underachievement. SCE obtained a load reduction of only 0.3% from non-residential customers, while PG&E obtained a 1.2% load reduction. PG&E called only nine events and SDG&E did not call any events during 2019. Applied Energy Group, p. 79.

[24] SEIA, Prepared Direct Testimony, p. 8, line 5 – p. 9, line 6.

design.[25] I am not persuaded that regulatory limits on the number of events is necessary for rate design, when an expected value can be identified and verified even more effectively. For example, even though SDG&E is allowed to call up to 18 events per year, it has never called more than nine events in a year.[26]

Accordingly, the Commission should eliminate the rigid constraints on the number of events in a year as well as any regulatory constraints on how the IOUs trigger CPP events.[27] The Commission should review the number of CPP events called by each IOU during each Phase 2 GRC, to ensure that each IOU's practices are aligned with its rate design assumptions and with system needs.

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

Q: How did other parties discuss potential adjustments to CPP and TOU periods?

A: In general, parties that testified on this topic assumed that CPP event and TOU peak periods of 4 PM – 9 PM would be appropriate.[28] (PG&E plans to maintain its even less-optimal 5 PM – 8 PM period for CPP events.[29]) Some parties discussed SDG&E's proposal to revise its CPP event period to 4 PM – 9 PM (from the current 2 PM – 6 PM CPP event period, in which net loads tend to be

[25] SEIA, Prepared Direct Testimony, p. 9, lines 8-13.

[26] SDG&E, Opening Testimony on Flex Alert and CPP Issues, p. 8, lines 5-6.

[27] The IOUs could assure their customers in program descriptions and other communications, that they will exceed some number of event days only under extreme conditions.

[28] See, for example, Cal Advocates, Ch. 1, p. 2, line 23 – p. 3, line 7.

[29] PG&E, Direct Testimony, Ch. 2, p. 5 line 29 – p. 6, line 8.

close to their minimum). No party gave significant consideration to emerging evidence that indicates that the 4 PM – 9 PM period is no longer optimal.

Q: Please briefly summarize why you recommended a 5 PM – 10 PM peak period in your direct testimony.

A: CPP and TOU peak periods should be aligned with the highest-cost hours, reflecting generation energy, generation capacity, and T&D costs. Effective and pending CPP and TOU periods end at either 8 or 9 PM, before the system net peak ends. The rotating outages initiated by CAISO on August 14 extended past 9 PM.[30] The Commission should be concerned that customers were experiencing outages at the very time that the rates for many customers were dropping.

It should also concern the Commission that during the 4 PM – 5 PM hour on August 14 and August 15, net demand on the CAISO system was not at a critical level. CAISO's Stage 3 Emergencies were called after 6 PM. Under the existing/pending 4 PM – 9 PM peak period designation, customers would have been receiving a price signal to reduce power demand well in advance of when it was needed, as well as a price signal to increase power demand before the emergency was clearly over.

As discussed in my direct testimony, this misalignment of price signals with the August 2020 net demand peaks is further supported by evidence in all three IOU Phase 2 GRCs. Unfortunately, leaving these matters to the Phase 2 GRCs will defer the potential benefits of adjusted CPP events and TOU peak periods to summer of 2022 at the earliest.

[30] CAISO, *Final Root Cause Analysis, Mid-August 2020 Heat Storm* (January 13, 2021), p. 35.

Q: Is there further evidence to support shifting to a 5 PM – 10 PM peak period?

A: Yes. SDG&E's testimony summarized its loss-of-load expectation (LOLE) analyses for the past three years, which generally show LOLE clustered in the later hours. Its December 2020 analysis indicates that "the highest likelihood of a loss of load event occurring is between 5 PM – 10 PM."[31]

PG&E recently submitted a marginal generation cost forecast in A.20-10-011.[32] It shows that for 2021, the highest priced generation hours are 5 PM – 10 PM, as shown in Figure 1. This is a shift from the 2017-2020 period: PG&E's modeling indicates that in those historical years, the highest priced generation hours are 4 PM – 10 PM. PG&E notes that, "the *forecasted prices peak up to an hour later than the historical simulated [prices]* … because both utility-scale and distributed (rooftop) solar generation are greater in the forecasted dataset compared to the historical simulations …"[33]

[31] SDG&E, Opening Testimony on Flex Alert and CPP Issues, p. 7 lines 11-12, 17.

[32] PG&E, Direct Testimony, *Commercial Electric Vehicle Day-Ahead Hourly Real Time Pricing Pilot,* A.20-10-011 (October 23, 2020), Chapter 2, pp 6-9.

[33] PG&E, Chapter 2, p. 9, lines 1-6. (*emphasis added)*

Figure 1: PG&E Forecast of 2021 Generation Prices by Percentile Rank

TABLE 2-1
FORECASTED 2021 GENERATION PRICES BY PERCENTILE RANK
(CENTS/kWh)

	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
Summer Percentiles																								
5th	8.5	8.1	7.8	7.7	7.8	8.0	7.1	5.3	5.3	5.1	4.9	4.9	5.0	5.2	5.3	5.3	6.5	7.6	9.1	10.3	11.3	10.7	9.9	9.2
10th	8.7	8.3	8.1	8.0	8.0	8.2	7.7	6.2	5.3	5.3	5.3	5.3	5.3	5.3	5.3	6.1	7.4	8.4	9.8	10.7	11.6	10.9	10.1	9.4
25th	9.1	8.7	8.5	8.4	8.5	8.7	8.5	7.3	6.1	5.5	5.4	5.5	5.7	6.0	6.6	7.7	8.7	9.6	10.5	11.5	12.1	11.2	10.4	9.6
50th	9.4	9.0	8.9	8.8	8.8	9.1	9.2	8.4	7.6	7.1	6.9	7.0	7.3	7.6	8.2	9.0	9.8	10.4	11.2	12.4	12.8	11.7	10.7	9.9
75th	9.6	9.3	9.2	9.1	9.2	9.5	9.7	9.2	8.5	8.1	8.0	8.2	8.5	8.7	9.2	10.0	10.6	11.1	11.9	21.1	62.5	12.3	10.9	10.1
90th	9.8	9.5	9.4	9.3	9.4	9.7	10.0	9.6	9.0	8.7	8.6	8.8	9.1	9.4	10.0	10.7	11.3	11.9	13.0	146.5	156.1	59.4	11.2	10.3
95th	9.9	9.6	9.5	9.4	9.5	9.8	10.2	9.7	9.2	9.0	9.0	9.1	9.4	9.7	10.4	11.1	11.7	12.3	46.8	209.2	205.9	106.8	11.3	10.4
Winter Percentiles																								
5th	8.9	8.6	8.5	8.5	8.4	8.6	8.8	7.8	5.6	5.3	4.9	5.0	4.9	4.9	5.3	5.3	7.2	9.4	11.4	10.8	10.4	10.3	9.8	9.3
10th	9.0	8.7	8.7	8.6	8.6	8.8	9.1	8.3	6.2	5.3	5.3	5.3	5.3	5.3	5.3	5.9	7.8	9.9	11.6	11.0	10.5	10.5	9.9	9.4
25th	9.2	9.0	8.9	8.9	8.9	9.1	9.5	8.9	7.3	6.1	5.7	5.7	5.6	5.7	6.0	7.0	8.6	10.8	11.9	11.3	10.8	10.7	10.2	9.6
50th	9.5	9.3	9.2	9.1	9.2	9.5	9.9	9.6	8.3	7.4	7.0	6.9	6.9	7.0	7.3	8.1	9.7	11.7	12.4	11.7	11.1	11.0	10.5	9.9
75th	9.7	9.5	9.5	9.5	9.6	9.9	10.4	10.1	9.0	8.4	8.1	8.0	8.0	8.1	8.3	8.9	10.4	12.3	12.9	12.2	11.5	11.3	10.7	10.2
90th	10.0	9.8	9.8	9.8	9.9	10.2	10.8	10.6	9.7	9.2	9.1	9.0	9.0	9.1	9.2	9.5	10.7	12.7	23.6	12.6	11.8	11.6	11.0	10.3
95th	10.2	10.1	10.0	10.0	10.1	10.4	11.1	10.9	10.0	9.6	9.4	9.4	9.4	9.4	9.5	9.8	10.8	13.0	66.3	48.1	12.1	11.9	11.1	10.5
Spring Percentiles																								
5th	8.4	7.9	7.6	7.5	7.5	7.8	7.3	5.3	4.2	3.7	3.7	3.7	3.7	3.7	3.7	3.7	4.0	5.3	7.5	9.9	10.8	10.2	9.5	9.0
10th	8.6	8.1	7.8	7.7	7.7	8.1	7.9	5.9	5.0	3.7	3.7	3.7	3.7	3.7	3.7	3.7	4.8	5.3	7.9	10.3	11.0	10.3	9.7	9.1
25th	8.9	8.4	8.2	8.1	8.2	8.5	8.5	7.0	5.3	5.0	4.3	4.1	4.2	4.2	4.3	4.7	5.3	6.3	8.6	10.8	11.3	10.7	10.0	9.5
50th	9.2	8.8	8.6	8.5	8.6	8.9	9.1	8.0	6.1	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.8	7.4	9.3	11.2	11.7	11.0	10.2	9.8
75th	9.5	9.1	9.0	8.9	9.0	9.3	9.6	8.8	7.4	6.1	5.4	5.3	5.3	5.3	5.5	5.9	7.1	8.5	10.1	11.7	12.0	11.3	10.5	10.0
90th	9.7	9.3	9.2	9.2	9.3	9.6	10.0	9.6	8.3	7.2	6.7	6.4	6.4	6.4	6.6	7.2	8.2	9.8	11.5	12.1	12.3	11.6	10.7	10.2
95th	9.8	9.5	9.4	9.4	9.4	9.8	10.1	9.9	8.7	7.8	7.3	7.2	7.1	7.3	7.3	7.9	8.7	10.4	12.0	12.3	12.5	11.8	10.9	10.3

The recent shift to a 5 PM – 10 PM peak period is further demonstrated by PG&E's analysis of summer extreme hours. As shown in Figure 2, PG&E's analysis places the 2017 – 2020 peak in the 6 PM – 9 PM peak period, while the 2021 peak period (in PG&E's Table 2-2) shifts to 6 PM – 10 PM. Looking to 2021, PG&E's modeling shows zero chance that there would be a summer extreme hour before 6 PM.

Figure 2: PG&E Analysis of Historical and Forecast Extreme Hours

TABLE 2-4
PERCENTAGE OF SIMULATED HISTORICAL JANUARY 2017 TO SEPTEMBER 2020
HIGHEST AND LOWEST PRICES BY HOUR AND SEASON

	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
SUMMER EXTREME HOURS																								
Percent High Hrs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.5	80.1	8.4	0.0	0.0	0.0
Percent Low Hrs	0.2	0.2	1.0	21.3	2.3	0.2	0.0	1.4	28.7	26.0	10.5	3.9	3.1	1.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WINTER EXTREME HOURS																								
Percent High Hrs	0.0	0.0	0.0	0.0	0.0	0.0	2.8	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	43.0	48.3	5.1	0.2	0.0	0.0	0.0
Percent Low Hrs	0.0	0.0	10.3	7.9	0.2	0.0	0.0	0.0	0.2	1.8	8.5	10.1	33.5	24.6	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SPRING EXTREME HOURS																								
Percent High Hrs	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.1	53.0	36.1	0.0	0.0	0.0
Percent Low Hrs	0.0	0.3	4.9	5.4	0.0	0.0	0.0	0.8	2.7	3.5	6.8	9.0	20.4	20.9	15.5	5.2	4.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0

TABLE 2-2
PERCENTAGE OF FORECASTED HIGHEST AND LOWEST PRICES
BY HOUR AND SEASON

	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
SUMMER EXTREME HOURS																								
Percent High Hrs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	32.7	66.6	0.2	0.0	0.0
Percent Low Hrs	0.0	0.2	0.2	0.7	0.4	0.2	0.0	0.8	7.0	25.7	44.1	16.3	3.7	0.6	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WINTER EXTREME HOURS																								
Percent High Hrs	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.1	71.7	9.4	0.2	0.5	0.0	0.0
Percent Low Hrs	0.0	0.0	0.9	1.0	0.1	0.1	0.0	0.0	0.5	8.8	20.8	20.8	26.2	16.8	3.1	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
SPRING EXTREME HOURS																								
Percent High Hrs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.9	48.9	39.9	0.0	0.0	0.0
Percent Low Hrs	0.0	0.4	6.5	7.2	0.0	0.0	0.0	0.0	1.4	3.6	7.6	9.4	23.6	18.5	13.0	5.1	3.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Q: Do you continue to recommend that the Commission should establish a statewide 5 PM – 10 PM peak period that applies to all TOU and CPP rates for all IOUs?

A: Yes. The Commission and the parties have expended substantial effort over the years to setting CPP event and TOU periods, based on now-outdated load data, and may be reluctant to rapidly adapt to changing load patterns. Unfortunately, California is facing substantial near-term costs for additional expensive supply and demand resources, which may be exacerbated by encouraging customers to resume normal operation at 9 PM. The Commission should not burden small businesses and other customers with costs that could be mitigated by sending customers more optimally timed price signals.

V. Demand Response Programs.

Q: Do you have any responses to testimony regarding changes to demand response programs?

A: Yes, I have three observations. First, each of the IOUs and several other parties have suggested different approaches to how an Emergency Load Reduction Pilot (ELRP) might be designed. While I will not summarize the different approaches, it appears from the proposed methods to initiate and communicate triggers that these programs would target large customers in 2021. Depending on the design, some of the program ideas could incorporate small businesses in 2022.

Some small businesses would be good candidates for an ELRP, particularly if their business model allows for flexibility to shut down operations for an evening. For example, a business might shift some operation (a print run, for example) to early the next morning. Small businesses should have the same opportunity for customized utility services as large businesses, where they can take advantage of them.

Second, PG&E, SCE and TURN support shifting from the annual lottery for the Base Interruptible Program (BIP) and allowing year-round enrollment up to the 2 percent reliability cap.[34] If the Commission agrees to open the Base Interruptible Program to all non-residential customers, as suggested in my direct testimony, this additional change would make the program more attractive to small business customers.

[34] PG&E, Direct Testimony, Ch. 4, p. 2, lines 19-27; SCE, Direct Testimony, p. 12, lines 8-18.

In a further twist on the BIP options, TURN suggests allowing both seasonal and full-year enrollments.[35] Since the major reliability issues arise in the summer, winter-only enrollments should not be allowed to fill up the enrollment cap. I support TURN's suggestion, but only if it is modified to allow customers to enroll in either full-year or summer-only programs.

Third, the IOUs recommend several increases in the frequency of demand response program call rates. SDG&E proposes increasing the maximum number of Capacity Bidding Program (CBP) events from 6 to 9 per month and increasing AC Cycling events from 20 to 25 events.[36] PG&E proposes increasing its maximum CBP events from 5 to 6 per month.[37]

All three IOUs forecast calling ten ELRP events per year.[38] Depending on the Commission's decision regarding the role of an ELRP relative to other load reduction programs, this could be excessive. For example, SDG&E has never called more than 9 CPP events in a year.

I do not take a position on the recommended changes to the number of events. However, the testimony on this does not provide a clear explanation of the structure for activating the various load management programs. Some of the ambiguity results from the need for flexibility to address local circumstances. In order to provide a clearer understanding, the Commission should consider advising the IOUs and CAISO as to its views on the order and

[35] TURN, Prepared Direct Testimony, p. 24, lines 14-19.

[36] SDG&E, Opening Testimony on Demand Response Issues, p. 12, lines 15-16, p. 13, lines 18-19.

[37] PG&E, Direct Testimony, Ch. 4, p. 5, lines 9-22.

[38] PG&E, Direct Testimony, Ch. 3, p. 9, FN 32; SCE, Direct Testimony, p. 10, line 14; and SDG&E, Opening Testimony on Demand Response Issues, p. 9, lines 19-20.

the primary basis for activating the various load management programs to address statewide reliability events.

In creating such a structure, the Commission should consider the number of events that are targeted for each load management program and ensure that the program designs embrace some degree of consistency in that respect.

Q: Does this conclude your testimony?

A: Yes.