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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking 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 (Filed November 19, 2020)

REPLY COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) ON THE ORDER INSTITUTING RULEMAKING TO ESTABLISH POLICIES, PROCESSES, AND RULES TO ENSURE RELIABLE ELECTRIC SERVICE IN CALIFORNIA IN THE EVENT OF AN EXTREME WEATHER EVENT IN 2021

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I. INTRODUCTION

Pursuant to the Order Instituting Rulemaking ("OIR") initiating this proceeding, issued by the California Public Utilities Commission ("Commission") on November 19, 2020, and Rule 6.2 of the Commission's Rules of Practice and Procedure, Pacific Gas and Electric Company ("PG&E") respectfully provides its reply comments.

II. PG&E'S RESPONSE TO OIR TIMING AND PROCESS

PG&E shares concerns[1/] regarding the schedule envisioned by the OIR, with the final decision currently scheduled for the end of May 2021. Given the timeframe, PG&E recommends that the Commission focus on: (1) changes to, or expansions of, existing demand response ("DR") programs in lieu of trying to develop new programs; and (2) feasible supply-side solutions as outlined below. PG&E further agrees with parties and reiterates that it would be virtually impossible to implement changes for the summer of 2021, if activities cannot be undertaken sooner. An expedited Ruling, perhaps by February 2021, providing some level of authority to take action for demand-side programs is warranted and should authorize the investor-owned-utilities ("IOUs") to track expenses in some manner (*e.g.*, a memorandum account) as indicated by Southern California Edison Company ("SCE") and suggested in

1/ SCE Opening Comments, pp. 3-4; California Independent System Operator Corporation ("CAISO") Opening Comments, p. 4; California Energy Storage Alliance ("CESA") Opening Comments, p. 4.

PG&E's opening comments.[2/] As it relates to whether this is a quasi-or ratemaking proceeding, PG&E believes the Commission has the discretion to characterize this proceeding as it sees fit.

III. PG&E'S REPLY COMMENTS

A. On How to Reduce Demand During the Peak Demand and Net Demand Peak Hours in the Event That a Heat Storm Similar to the August 2020 Storm Occurs in the Summer Of 2021.

1. Should the Commission consider directing the IOUs to design a new paid advertising program for distributing CAISO's Flex Alerts in various outlets, including social media? If so, how should the Commission authorize a budget dedicated to this purpose and what measures and budget level should be considered?

No reply comments at this time.

2. Should the Commission modify the Critical Peak Pricing (CPP) program to increase the number of allowed events per year, modify other attributes, or provide guidance on when the program should be dispatched?

PG&E acknowledges and agrees with the California Efficiency + Demand Management Council ("CEDMC") and CPower and Enel X North America, Inc. (Enel X) (collectively "Joint Demand Response ("DR") Parties") that general implementation timing may be challenging prior to the start of the 2021 DR season.[3/] PG&E acknowledges shifting the SmartRate™ program event hours to align with 4 – 9 p.m. peak demand would be helpful, as stated by the California Independent System Operator Corporation ("CAISO"), California Solar & Storage Association ("CALSSA"), and the Joint DR Parties, and notes that changes to the SmartRate program event hours from 2 – 7 p.m. to 5 – 8 p.m. will be completed after the 2021 season.[4/] For PG&E's Peak Day Pricing ("PDP") program, PG&E filed Tier 3 Advice Letter ("AL") 5861-E

2/ SCE Opening Comments, pp. 3-4; PG&E Opening Comments, p. 3.

3/ CEDMC Opening Comments, p. 3; Joint DR Parties Opening Comments, p. 5.

4/ Because the change of event hours is a structural change (as compared to a value change), this rate modification work must be executed in a way that does not conflict with other structural rate modifications. There are several required structural changes that are being implemented in Q1 and Q2 of 2021 that preclude the ability to implement the SmartRate event hour change before the season begins.

on June 26, 2020, to implement changes to the PDP event hours in March 2021, along with other changes to its PDP program. There were no protests, but PG&E is still waiting for draft and final resolutions approving AL 5861-E.

Though PG&E and San Diego Gas & Electric Company ("SDG&E") have different event occurrence requirements (SDG&E has an eighteen event maximum; PG&E has a fifteen event maximum) and therefore a different view on increasing event maximums, PG&E agrees that by modifying the number of events allowed customers could experience bill volatility.[5/]

While PG&E supports a discussion to allow Option R and Option S to participate in PDP as suggested by CALSSA and the Joint DR Parties, the rate design will need to be addressed in the next General Rate Case or rate design window. Option S is currently a PG&E pilot program and has been approved up to a 50-megawatt ("MW") cap per eligible rate schedule.

3. Should the Commission explore potential options to encourage non-IOU LSEs to develop programs similar to CPP?

PG&E would like to correct the statement from Alliance for Retail Energy Markets ("AReM"), Direct Access Customer Coalition ("DACC"), and The Regents of the University of California (collectively, "Joint DA Parties"):

> The Commission has previously acknowledged that existing barriers impede the development of demand response ("DR") programs by non-utility LSEs. In Rulemaking ("R") 13-09-011, AReM and DACC explained that the DR programs operated by the investor-owned utilities ("IOUs") were funded through distribution rates, which created barriers to entry for non- IOU LSEs who wished to provide their own DR programs, restricted competition, and raised costs for consumers. Specifically, AReM and DACC noted that the IOUs were treated preferentially because their DR program costs were guaranteed cost recovery from all customers through distribution rates with little to no risk of shortfall or non-recovery.[6/]

PG&E's CPP programs, SmartRate, and PDP are funded through generation rates, and not distribution rates. Therefore, costs are only recovered from IOU bundled service generation customers.

5/ SDG&E Opening Comments, p. 9.

6/ Joint DA Parties Opening Comments, pp. 2-3.

PG&E acknowledges the impact of Community Choice Aggregation ("CCA") formations on eligible IOU CPP customer enrollment, as outlined in SDG&E's comments: "Although SDG&E has not yet experienced significant load departure in its service territory, forecasts reflect the expectation that between 2020 and 2023 SDG&E's bundled load will decrease by approximately 60 percent due in large part to anticipated CCA formation. SDG&E's current CPP program will be available only to remaining bundled service customers."[7/] Similarly, PG&E currently serves roughly 40% of electric load in its service territory, which results in a much smaller customer base that is eligible for utility CPP programs.

4. Should the Commission increase IOU marketing funds to increase enrollment in CPP or take other actions to increase customer participation in the program?

No reply comments at this time.

5. Should the Commission establish a new out-of-market and outside the RA framework emergency load reduction program (ELRP) that could be dispatched by CAISO/IOUs under specified conditions where participants are compensated only after the fact and based only on the amount of load reduction achieved during the dispatch window? If so, what are the key program design elements (e.g., dispatch conditions, compensation level, load reduction measurement considerations, target customer segments, etc.) that should be considered or incorporated? What other issues (such as interactions with existing supply-side and load-modifying programs) need to be considered in order to establish an ELRP? How should these issues be addressed?

PG&E observes that most parties appear to support an ELRP. PG&E reiterates its support for the development of an ELRP as a *pilot*. A realistic goal for 2021 would be for the IOUs to stand up a rudimentary ELRP pilot and potentially layer-in additional enhancements for 2022. While certain parties shared their views on design elements, PG&E believes that if the Commission intends to have the IOUs stand up a pilot for 2021 then simplicity should be a key driver.

7/ SDG&E Opening Comments, pp. 10-11.

6. Should the Commission allow BTM hybrid-solar-plus-storage assets to participate and discharge their available capacity in excess of onsite load (and thus export to the grid) and receive compensation for the load reduction, including exported energy, under ELRP? Should this capability be expanded to include BTM stand-alone storage as well? Are there any Rule 21 or safety and reliability considerations that need to be addressed to permit storage, with or without NEM pairing, to export energy while participating in the ELRP? How should any safety and reliability issues be addressed?

As stated in its opening comments, PG&E does not support DR export for any of its programs or for the yet-to-be-developed out of market ELRP, as many regulatory processes, including ones associated with the Rule 21 interconnection study process, would need to be updated and tools for visibility and control would be needed to accommodate such a sweeping change. Behind-the-meter ("BTM") exporting is not only complex in nature but could have significant safety and reliability ramifications if not carefully vetted. In addition, most customers with BTM solar-plus-storage are participating in one of PG&E's Net Energy Metering ("NEM") programs. The Commission has established careful protocols to ensure the integrity of the NEM programs for customers who combine solar and storage.[8/] Where those protocols require non-export from the storage, reconsideration of the NEM integrity issue would need to be addressed. PG&E is concerned that, as suggested by other parties, resolving these issues by May would be challenging in light of the regulatory changes and systems needed to support such a change.

7. Should the Commission allow BTM Back-Up Generators (BUGs) to participate in and receive compensation under the ELRP? If so, are there any Rule 21, safety and reliability, or other considerations that need to be addressed in order to permit BUGs to operate to reduce load or export energy while participating in the ELRP? How should these issues be addressed?

While there may be benefits associated with waiving of the BUGs prohibition during emergencies, these benefits would depend on the specific configuration (*e.g.*, size of unit(s), connection, Rule 21 provision, etc.) of each DR participant. Moreover, there may need to be additional considerations, including air permit waivers. While PG&E expressed its thoughts on

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8/ *See* Decision ("D.") 14-05-033 and D.16-04-044, as well as specific NEM tariffs.

the use of renewable fuels in its opening comments,[9] the use of BUGs—whether or not their use falls under the prohibited resources restriction (*i.e.*, fossil fueled)—could be a source of MWs that can support grid needs and therefore should be explored.

B. On How to Increase Energy Supply During the Peak Demand and Net Demand Peak Hours in the Summer of 2021.

8. Should the Commission consider expedited procurement, including through the cost allocation mechanism for additional reliability procurement (e.g., expansion of existing gas-fired resources) that could be online for Summer 2021 and 2022? If so, how could this occur in order for the additional capacity to be online on time to address summer reliability needs. If not, why not?

a. Scope and Coordination

Based on parties' opening comments, PG&E believes that it would be useful and efficient to narrow the scope of the potential actions that can be feasibly taken by the Commission to ensure reliability in the event of an extreme or extended heat storm in summer 2021. For instance, new steel-in-the-ground resources simply are not feasible for summer 2021 and should be ruled out of scope or, at a minimum, not be the primary focus for supply-side solutions. However, there may be some opportunities for upgrades or operational changes at existing generation facilities that could be completed in time, if action is taken expeditiously, and therefore should remain in scope. Also, firm energy that can meet the net peak load, as proposed by SCE, and, in particular, firm energy imports, also should be explored and included in the scope.[10] Any resources that are leaning towards retirement should also be re-contracted for summer 2021, as argued by CAISO in their opening comments.[11] Lastly, any additional capacity should be able to address both the gross peak and net peak load, as argued by CAISO.[12]

9/ PG&E's Opening Comments, p. 9.

10/ SCE Opening Comments, pp. 19-20.

11/ CAISO Opening Comments, p. 3.

12/ CAISO Opening Comments, p. 9.

Upgrades at existing generation facilities should be selected carefully, given the risks that the Public Advocates Office ("Cal Advocates") notes to reliability if the projects are not completed in time and the facilities are not returned to service for the summer months.[13/] PG&E also shares the concerns of Cal Advocates and other parties about not using this OIR as a means to expand the gas fleet in a way that sets the state back on its decarbonization path.[14/] PG&E fully supports California's decarbonization goals and agrees with parties that oppose retrofits to plants that are expected to retire soon, like the once-through cooling plants, as such retrofits would not be a good use of customer funds.[15/] However, PG&E believes it is important that California demonstrate that it is possible to decarbonize the grid and do it reliably. Therefore, PG&E believes it is essential that reliability problems not persist into summer 2022 and beyond. Sensible upgrades to the gas fleet that are likely to be needed for the foreseeable future are reasonable paths to explore and may be one of the few ways to quickly add additional capacity for summer 2021. Lastly, as some parties have argued for expanding the scope to include 2023 and 2024,[16/] PG&E recommends assessing relevant plants for upgrades by leveraging the existing Integrated Resource Planning ("IRP") proceeding and the framework and structure being developed in that proceeding to ensure system reliability beyond the immediate system reliability concerns. PG&E also supports coordination between this OIR and California Energy Commission ("CEC") docket 20-SIT-01, which is exploring "efficiency upgrades," as suggested by Cal Advocates, as cost recovery and allocation issues of any approved upgrades would need to be handled by the Commission. Regarding timing, should the Commission deem additional procurement to be needed, PG&E supports parties that argue that authorization should happen as soon as possible.

13/ Cal Advocates Opening Comments, p. 5.

14/ Cal Advocates Opening Comments, pp. 6-7; CEERT Opening Comments, p. 8.

15/ CEERT Opening Comments, pp. 2-3.

16/ LS Power Development Opening Comments, p. 2; CESA Opening Comments, pp. 2-3.

Lastly, numerous parties argue that given the timing, the Commission may need to place greater emphasis on demand-side solutions, such as DR for any identified near-term reliability needs.[17/] PG&E agrees and looks forward to working with parties to identify additional supply-side and demand-side solutions in response to the OIR.

b. Approach

As described below, the Commission may have to consider procurement responsibility as a multipronged approach. Several parties offer different recommendations on how to conduct any incremental capacity procurement. SCE recommends bilateral contracting by the IOUs with recovery through the existing Cost Allocation Mechanism ("CAM") for procurement done by the IOUs on behalf of the system, with Calpine Corporation taking a similar position.[18/] PG&E agrees that bilateral contracting, if the IOUs are directed by the Commission to bring additional capacity online, is likely the fastest path to meet the needs for summer 2021 and that all customers should equitably share in the cost of ensuring reliability, making CAM cost-recovery the best option for broad allocation of costs and benefits. Note that the CAISO capacity procurement mechanism ("CPM") would also offer broad cost recovery, but it would not be able to offer contract terms (*i.e.*, duration) that are likely needed for plant upgrades to be economic.

9. If the CEC, CAISO, or the CPUC conducts additional analyses regarding Summer 2021 load forecasts, should the Commission consider a mechanism to update RA requirements in April for the summer of 2021 or would it be appropriate for CAISO to use its capacity procurement mechanism (CPM) to procure additional capacity for the summer of 2021, should it be deemed necessary?

As indicated below, PG&E agrees with parties' opening comments that additional analyses to determine the near-term reliability needs for the summer of 2021 is warranted. Based on the identified list of options for supply-side solutions, the Commission may have to consider

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17/ SCE Opening Comments, p. 3; NRDC Opening Comments, p. 1; Cal Advocates Opening Comments; Center for Energy Efficiency and Renewable Technologies (CEERT) Opening Comments, p. 2; California Environmental Justice Alliance, Sierra Club, Union of Concerned Scientists and Grid Alternatives (collectively "Joint Justice Parties") Opening Comments, pp. 2-3.

18/ SCE Opening Comments, pp. 12-15; Calpine Opening Comments, pp. 1-2.

procurement responsibility as a multipronged approach. For example, supply-side solutions focused on retrofits or operational changes to existing generation facilities to increase output may need to be the responsibility of LSEs, given that only one or a small number of LSEs have an existing contract with that generating facility. Centralizing such procurement through CAISO may not be feasible, given that CAISO does not have authority for multi-year procurement, which is what suppliers have stated is needed to complete facility upgrades and ensure cost recovery. In contrast, supply-side solutions that are focused on incremental imports from neighboring balancing authority areas may need to be procured under a centralized approach, such as through CAISO's CPM. The same goes for contracting with existing generation facilities that are expected to retire or mothball or in the absence of a contract. For example, if the Commission identifies a procurement need of 200 MWs and allocates the need among all Commission-jurisdictional LSEs with a limited pool of existing physical resources or incremental imports to select from, that determination is likely to create a seller's market. As pointed out by Cal Advocates, LSEs could be challenged by very high prices due to the short time period, tightness in the market, and competition from numerous other LSEs.[19/] While procurement responsibility may ultimately depend on how the Commission plans to meet the identified need through supply-side solutions, PG&E reiterates its opening comments that it will take collective action by everyone to ensure reliable electric service in the event of an extreme and/or extended heat storm in summer 2021.

10. Should the Commission undertake a stack analysis of the amount of resources that would be necessary for Summer of 2021?

As a general matter, PG&E continues to believe that a thorough understanding of potential resource shortfalls is necessary to address reliability concerns or adjust RA procurement requirements. Parties' opening comments demonstrate that the Commission currently has two primary options for determining the reliability need in the event of an extreme

19/ Cal Advocates Opening Comments, pp. 7-8.

and/or extended heat storm for summer 2021: (1) a stack analysis or (2) a stochastic modeling approach. PG&E does not have a preferred approach at this time but agrees with parties' opening comments that each approach has its own challenges and benefits. While PG&E agrees with Cal Advocates and others that a stack analysis is not the best or most useful method to determine potential resource shortages, an alternative method, such as a production simulation model or a Loss of Load Expectation ("LOLE") analysis, is unlikely to be thoroughly vetted or completed in the short period of time available to invoke immediate action by the Commission. That said, PG&E agrees with AReM and CAISO, however, that the analysis undertaken by the Commission should focus on both the gross peak and net peak hours.[20/]

PG&E notes that CAISO and SCE provided a stack analysis and a LOLE analysis, respectively, in their opening comments. Should the Commission decide that a stack analysis is not sufficiently rigorous and that a stochastic modeling approach is not feasible in the allotted time, the Commission may want to explore validating and leveraging the analyses provided by CAISO and SCE.

In addition to developing a more robust understanding of a potential resource shortfall, the Commission should endeavor to develop a more complete understanding of the resources available to reduce that potential shortfall, including resources not already under an RA contract and new resources expected to come online prior to the summer of 2021. PG&E reiterates its opening comments that the Commission consider LSE submission of a preliminary, non-binding RA plan that demonstrates 100% RA compliance to assist in this analysis and review and ensure that RA resources are not left on the table.

Finally, while PG&E acknowledges that the out-of-state export issue is complicated and likely not the singular cause of the August 2020 rolling blackouts, it does support The Utility Reform Network ("TURN") and Protect Our Communities Foundation's ("PCF") recommendation that the Commission coordinate closely with the CAISO to further assess and

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20/ CAISO Opening Comments, p. 10-13, 19; Joint DA Parties Opening Comments p. 5, 7-8.

address operational changes in the CAISO's market—specifically regarding prioritization by the CAISO of exports over in-state load during emergency events—to ameliorate such problems in the future.[21/]

11. Should the Commission consider requiring that load serving entities expedite the IRP procurement they have scheduled to come online? How would the Commission provide equitable incentives so that the expedited process does not disproportionately increase costs for that LSE? If so, please explain how this would work. If not, why not?

Multiple parties, including Shell Energy North America (US) ("Shell"), L.P., Independent Energy Producers Association, Middle River Power, LLC and SCE, expressed concerns about the potential for a Commission-ordered expedited IRP procurement to be counterproductive and ineffective.

Firstly, PG&E echoes Shell's statement that if incentivized to expedite IRP procurement LSEs may "rob Peter to pay Paul" by diverting resources away from unfinished projects with low liquidated damages in order to accelerate other projects. This reallocation of services (e.g. construction and engineering or materials and labor) could inevitably increase costs for customers and may not ultimately result in a "net benefit" if delays to expected resources would not have otherwise occurred without a reallocation of services.

Furthermore, PG&E agrees that tight supply conditions should provide sufficient incentive for developers to accelerate projects that can feasibly be accelerated. However, should the Commission expedite IRP procurement, it should ensure that no "expedited premiums" are allocated without sufficient reasonableness review and are only allocated to all entities receiving value from those resources.

21/ TURN Opening Comments, p.7; PCF Opening Comments, p. 2.

12. Are there other opportunities for increasing supply for the summer of 2021 and/or reduce demand that the CPUC has not considered? If so, please provide details of these supply or demand resources and please explain how they can address reliability needs in the timeframe discussed in this OIR.

As indicated in its opening comments, PG&E is exploring whether to offer residential customers with an ELRP *pilot* program. Such a residential ELRP pilot, using programmable smart thermostats among other technologies, is envisioned to be separate but potentially related to the non-residential ELRP in certain design elements (e.g., triggers). PG&E believes that a residential component may not only provide additional resources for the near-term but could also serve as a sandbox for future program design with policymakers' push to a broader "load management" framework.[22/]

13. Should the Commission consider revisions to the reliability DR programs (Base Interruptible Program-BIP, Agriculture Pump Interruptible-API, AC cycling) that allow these programs to be triggered before the Warning stage (e.g., after an Alert in the day-ahead timeframe)? If so, under what conditions and how would this work? If not, why not?

No reply comments at this time.

14. Are there other changes to the BIP that would make it more effective to meet load under a variety of conditions during the summer of 2021 (e.g., expansion of the 2% cap, mid-year enrollment, trigger notification time, etc.)?

While PG&E believes a rolling enrollment process may help maximize the number of participants in the BIP program under the existing 2 percent reliability cap, it would require that the Commission suspend the existing lottery process that was established through D.18-11-029. The Commission should make the enrollment process more flexible to ensure the BIP program is fully subscribed before attempting to raise the existing 2 percent reliability cap. As indicated in opening comments, PG&E does not support a rolling *unenrollment* process, as that would create

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22/ *See* CEC's Load Management Rulemaking (19-OIR-01), available at https://www.energy.ca.gov/proceedings/energy-commission-proceedings/2020-load-management-rulemaking.

uncertainty of available MWs and potentially incentivize participants taking advantage of the revised process.

15. Should the Commission consider authorizing another variation of the IOUs' Capacity Bidding Program in which customers can be dispatched in the Real-Time Market (RTM) under specified conditions? If so, what should be the required program attributes and dispatch conditions?

While PG&E may consider adding a Day-Of ("DO") option to its Capacity Bidding Program ("CBP") tariff, it would be difficult to implement by summer of 2021. While this may be a possibility for 2022, clarity on the benefits of a DO option should be determined before moving forward. The value of a DO offering may also depend on what the triggering mechanism for the ELRP will be (*e.g.*, Day-Ahead and/or Day-Of). As SCE points out in its opening comments, the establishment of an RTM option could very well "cannibalize" its Day-Ahead CBP option.[23/] Ideally, any additional CBP option would help promote incremental MWs rather than simply creating a shift. Lastly, it should be noted that PG&E already offers three variations of its Day-Ahead CBP program (Prescribed, Elect, and Elect +), which provides additional flexibility to participants in the Day-Ahead market.

16. Should the Commission order a supplemental Demand Response Auction Mechanism (DRAM) auction to be held in early 2021 to procure additional DR resources for summer 2021 (e.g., July – September)? If so, what level of budget authorization should be considered and why?

PG&E reiterates that the DRAM auction schedule cannot accommodate a late May 2021 decision in the OIR and then delivery in July 2021. As supported by SDG&E and Cal Advocates and D.19-07-009, the accelerated timelines supported by demand response providers are simply not realistic, and there is insufficient time for the Commission to issue a decision authorizing a

23/ SCE Opening Comments, p. 24.

supplemental DRAM, the IOUs to administer the request for offer, and Sellers to deliver for July 2021.[24/]

PG&E also supports SCE, SDG&E, and Cal Advocates' comments that the DRAM pilot should not be expanded prematurely and without the results of the DRAM evaluation.[25/] D.19-07-009 specifically rejected expansion of DRAM due to "mixed results" from the initial evaluation of the pilot.[26/] Similarly to SDG&E and Cal Advocates, PG&E agrees that DRAM resource performance from the August heat wave appears to be rather mixed, with a substantial portion of the resources significantly underperforming, even when assessed generously under the DRAM Agreement as the best two consecutive hours of performance in August. Such underperformance requires further evaluation to determine if DRAM performance can be improved, and it is premature at this time to expand the DRAM pilot with the types of reliability issues that are present today. PG&E supports Cal Advocates in urging the Commission to exclude consideration of an additional DRAM auction from the scope of this proceeding.

17. Should the Commission explore short-term measures to expand electric vehicle (EV) participation in currently available DR programs (IOU DR, DRAM, non-IOU LSE DR)?

No reply comments at this time.

24/ SDG&E's Opening Comments at p. 22; Cal Advocates' Opening Comments at p. 10; D.19-07-009 at p. 35 states that "[w]e recognize the urgency expressed by the Providers to move the process along but the expedited timelines recommended by these parties are not realistic."

25/ SCE Opening Comments at pp. 24-25; SDG&E Opening Comments at pp. 22-24; Cal Advocates Opening Comments at pp. 9-10.

26/ D.19-07-009 at p. 15 and p. 27, which states, "Because the Auction Mechanism has not successfully met all six criteria, we should not expand its role nor adopt it as a permanent mechanism at this time."

18. Should the Commission consider measures to minimize potential attrition and loss of capacity in existing utility DR programs, such as increasing incentives, reducing dispatch activity limits, and clarifying expectations regarding when programs are dispatched?

PG&E agrees with the CAISO that its DR offerings should provide for greater "flexibility" and "optionality."[27/] However, this must be balanced with customer fatigue and attrition as well as ensuring the resources are "used and useful." One approach to create such balance stems from graduated variations in existing programs. For example, certain parties expressed support[28/] for PG&E's current CBP program, which offers three sub-options with Prescribed, Elect, and Elect+. Separately, PG&E is open to extending CBP to the weekend period and possibly DO, as this would provide additional grid support. PG&E is also interested in ensuring resources are "used and useful" and suggest lowering the bid cap for CBP Elect from the CAISO bid cap of $1,000/MWh to $650/MWh.[29/] PG&E is ready to include this modification along with others it its January 25, 2021 proposal filing.

As it relates to BIP, PG&E is assessing the possibility of offering different variations of this critical emergency program based on differentiated performance requirements which would be accompanied by varying compensation structures based on availability. Likewise, several parties have called for more flexibility in the BIP enrollment process, which PG&E supports and is ready to include a proposal for rolling enrollment in its January 25, 2021 proposal filing.

At the same time, a number of parties have called on placing limitations and prescriptive conditions on both BIP and CBP.[30/] Rather than trying to determine what is an appropriate limitation or preference, which can vary significantly from party to party, PG&E prefers to provide greater flexibility as discussed above. As such, there may be variations within a program that provides for lower performance requirements and therefore lower compensation.

27/ CAISO's Opening Comments at p. 21.

28/ CEDMC Opening Comments, p. 12.

29/ PG&E's CBP Prescribed option utilizes a $95/MWh trigger price. Available at https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_E-CBP.pdf

30/ *See* NRG Opening Comments at p. 7 and CLECA Opening Comments at p. 15.

Conversely, higher performance requirements could merit higher compensation. PG&E believes this is a more viable pathway over trying to have a single programmatic option that attempts to optimize requirements for all parties. In tandem with programmatic variations, it may be appropriate to assess whether current incentive levels are sufficient in light of projected grid needs.

Finally, any relaxation, even partially, of the dual participation rules in the context of the launch of an ELRP must be done carefully. For instance, nothing may really be gained if relaxation just results in migration from one DR program to another if ELRP incentive levels and participation requirements are more desirable to participants. Dual participation measures are also required to prevent calling on a resource under different programs at the same time—avoiding both double counting the resource's response and double compensating it for the same capacity and energy for the same intervals.

IV. CONCLUSION

PG&E appreciates the opportunity to submit these reply comments and looks forward to working through the issues identified herein with the Commission and the parties.

Respectfully submitted,

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