Docket No. R.20-11-003

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Date: September 1, 2021

Witnesses: Catherine Yap
Paul Nelson

TESTIMONY OF
CATHERINE YAP AND PAUL NELSON
ON BEHALF OF THE
CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION

September 1, 2021

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I. Introduction

This testimony is presented by Catherine Yap and Paul Nelson on behalf of the California Large Energy Consumers Association ("CLECA). Ms. Yap has four decades of experience preparing and delivering testimony regarding utility ratemaking before this Commission as well as in other jurisdictions. Paul D. Nelson has nearly three decades of experience in utility ratemaking. Ms. Yap's statement of qualifications is included as Attachment A to this testimony. Mr. Nelson's statement of qualifications is included as Attachment B to this testimony.

All CLECA members participate in the Base Interruptible Program (BIP) demand response program. The members provided hundreds of megawatts (MW) of the load drop during the summer 2020 heat storms, avoiding or reducing the impact of rolling blackouts. They remain committed to participation in demand response (DR) but the events of this past summer were very disruptive to their operations and to their ability to provide products to their customers.

The testimony responds to the August 10, 2021, Assigned Commissioner's Amended Scoping Memo and Ruling for Phase 2 (Amended Scoping Memo). That document requested input on the development of additional supply and demand side resources to increase peak and net peak supply resources in 2022 and 2023 and proposals to reduce peak and net peak demand in 2022 and 2023.[1] The Amended Scoping Ruling was triggered by Governor Newsom's July

[1] Amended Scoping Memo at 3-4.

31, 2021, emergency proclamation.[2] This testimony also responds to proposals in the Summer Reliability OIR Staff Concepts Paper dated August 16, 2021.

II. It Is Important Not to Repeat Mistakes that Were Made in the Past While Responding to the Capacity Shortage

As the ALJ Ruling notes, we are facing a potential shortfall in capacity during the next two summers if the weather is hotter than normal. While this is indeed cause for concern, it should be noted that it is not the first time that the State has faced a serious capacity shortage. In the winter of 2000-2001, during the "Energy Crisis", the State decided to take action that led to the Department of Water Resources negotiating and signing a large number of very expensive long-term power purchase agreements that ratepayers were forced to pay for through significant rate increases. Negotiating for long-term power purchase agreements during a period of shortfall disadvantages ratepayers because suppliers have market power under those circumstances. Thus, we strongly urge the Commission to focus on shorter-term solutions to augment capacity during the current shortfall period while continuing to require that the utilities pursue cost-effective procurement practices.

We are particularly concerned about the lack of any discussion in the Staff Concept Paper of cost-effectiveness, except for smart thermostats. Reliability is very important but so is the cost of electricity which continues to increase rapidly due to various factors. The Commission must find the correct balance between reliability and cost. We urge the Commission to evaluate the projected cost of proposals to ensure that ratepayers do not overpay for capacity.

One approach to managing the cost would be to employ cost benchmarks based upon the cost of utility contracts for generation capacity entered into during 2020 by the utilities in

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[2] Ibid. at 2.

response to D.19-11-016. While we recognize that the recent increase in demand for new capacity on an expedited basis may drive up market prices, it is important to have the 2020 prices as a basis for comparison. Furthermore, it may be appropriate to refuse capacity alternatives if suppliers appear to be exercising market power by increasing their costs significantly beyond the levels offered in 2020. In any case, if prices are much higher than the 2020 levels, contracts should be for the shortest term possible.

As we discuss below, we are concerned that dispatching the Emergency Load Reduction Program (ELRP) on the basis of a Grid Alert will risk unnecessary costs for ratepayers because ELRP is an expensive source of electricity and a Grid Alert may be called on a day-ahead basis but an actual capacity shortage may not occur in real-time. When ELRP is called in the day ahead, but the shortage does not materialize in real-time, customers are paying $1000/MWh for the load reduction while market prices may remain much lower, driving up rates. We are concerned that no assessment has been done to demonstrate why $2/kWh (which equates to $2000/MWh) is an appropriate payment in the ELRP, although we certainly agree that higher compensation should be paid for a committed load reduction compared to an uncertain one.

III. A Renewed Proposal for Additional Resources to Reduce Peak and Net Peak Demand in 2022 and 2023.

As in previous testimony in this proceeding, CLECA recommends reintroduction of a past demand response (DR) program called the Demand Bidding Program (DBP) that could be used on a regular basis with a day-ahead trigger that did not require an emergency to be initiated. It ended in 2016 for Pacific Gas and Electric (PG&E) and in 2017 for Southern California Edison (SCE). It was a cost-effective program but was difficult to integrate into California Independent System Operator (CAISO) markets; as a result, it was discontinued. As the Commission has adopted the ELRP that will not be integrated into the CAISO market[3], there is now precedent for adding another program that would not be integrated.

This program would be in addition to the ELRP and the BIP and would focus on reducing usage during periods that are energy-constrained rather than capacity-constrained. The DBP could offer energy reductions at a price that is lower than the ELRP price.

Program participation would be voluntary, the program would be operated by the IOUs, and program events would be triggered in response to CAISO market prices or local transmission and distribution conditions. Compensation for the program would be paid on a dollar per MWh basis after-the-fact and would be based on the energy use reduction achieved. The advantage of a day-ahead program is that it is easier for customers to pre-plan their operations on the day of the DR event, which should encourage greater customer participation. In contrast, ELRP can be called on either a day-ahead or day-of basis.[4] Since the DBP would only be triggered on a day-ahead basis, the compensation would be lower than for ELRP, in exchange for greater customer control of their own load reduction.

For industrial customers, a day-ahead program is less disruptive to their manufacturing processes. Under DBP, customers would effectively nominate the amount of DR that they could provide the next day based on the equipment they could turn off. Since that equipment is "lumpy," it provides a certain amount of load reduction and cannot be broken up into specified increments. This was a significant problem in integrating the DBP into the CAISO market because the load reductions required discrete dispatch in specified increments and could not be partially dispatched. Such a reduction is much like getting down to a firm service level (FSL) under the BIP program, which is also a form of discrete dispatch. Discrete dispatch is permitted

[3] D.21-03-056 at 19-20.
[4] D.21-06-027 at 4.

under the CAISO tariff for reliability demand response resources (RDRR) but not for proxy demand resources (PDR).[5] However, we note that a DBP program that allows "lumpy" load reductions would be analogous to a generating plant that has multiple stages, i.e., some combined cycle plants, that do not occur in neat variable dispatchable amounts.

An important consideration in the context of improving reliability for the summer of 2022 is that the DBP could be brought back readily. Prior utility tariffs for the previous DBP could be relied upon for the DBP pilot with a minimum of modification. Customers formerly on the program would be familiar with it and ready to re-engage. Since customers will nominate their load drops on a day-ahead basis, these amounts can be included on the utility spreadsheets of expected demand response sent daily to the CAISO.

DBP was also designed to allow dual participation by customers engaged in day-of RDRR programs such as BIP, under the condition that if a reliability event was called, the customer would only receive compensation through the BIP incentive and not under the DBP. We recommend that this protocol be continued. This is in contrast to ELRP, where only an increment of load reduction beyond that provided under BIP by going down to the FSL would be compensated.

IV. Proposal to Address Increasing Forced Outages of Gas-Fired Generation During Severe Heat Events

While the Commission has decided not to authorize any new gas-fired generation, existing gas-fired generation has been relied upon during the severe heat events in 2020 and 2021. This is particularly true given the current low hydro availability and reduced solar output due to smoke from wildfires. We note there has been an increase in forced outages during 2020-

[5] CAISO Tariff Section 30.6.2.1.2.2.

2021 compared to 2019, with 2020 having 2500 MW of forced outages due to plant maintenance issues or equipment failures and 5300 MW of forced outages for other reasons.[6] In May of this year, the Russell City Energy Center had a catastrophic steam turbine failure and explosion.[7] The California Energy Commission approved the operation of Russell City in simple cycle operation.[8] When Russell City received a California Independent System Operator (CAISO) Capacity Procurement Mechanism (CPM) designation in August 2021 to supply needed capacity, it was for 350 MW, not the original output of the facility at roughly 600 MW.[9]

It is critical to maintain the current fleet of gas-fired generation if it is to remain available to provide reliability during severe heat events and to integrate renewables; however, it is not clear that generators are earning sufficient revenues through market mechanisms to underwrite expanded maintenance activities. There may be augmented maintenance or repair activities that could be conducted at existing sites that would ensure the reliable provision of capacity and, possibly, the restoration of capacity lost due to equipment failure or damage, if additional funds were provided. There may also be opportunities to provide some augmentation to capacity through the addition of equipment such as chillers that might make the existing turbines work more efficiently during high temperature weather events.

We recommend that the Commission direct the utilities to conduct a procurement bidding process that seeks bids for maintenance and repair activities that would be undertaken in the short-term to provide support for more reliable operations at these existing generation sites. The cost effectiveness of capacity restoration and augmentation could be compared to other available

[6] Department of Market Monitoring Annual Report on Market Issues and Performance for 2020 at 55-58.
[7] https://www.hayward-ca.gov/your-government/departments/city-managers-office/russell-city-energy-center
[8] https://efiling.energy.ca.gov/GetDocument.aspx?tn=238943&DocumentContentId=72362
[9] http://www.caiso.com/Documents/AdditionalAugust2021SignificantEventCapacityProcurementMechanismDesignation.html

alternatives in determining the best overall portfolio for improving the availability of resources during the summers of 2022 and 2023. It should be noted that forecasts of grid resources over the next decade show continued reliance on natural gas-fired capacity so the ratepayer investment in restored and augmented capacity would be available to be drawn on over the upcoming decade not just the summers of 2022 and 2023.

Providing existing generation with capacity restoration and augmentation for high temperature events could provide cost-effective means for minimizing reliance on other capacity additions made through temporary reliance on diesel-fired back up generators. While there would be an incremental increase in the use of the existing gas-fired generation associated with the restored or augmented capacity, the emissions consequences would be significantly lower than those associated with reliance on diesel-fired backup generators to provide the same amount of capacity.[10,11]

V. Some Proposals in the Staff Concept Paper Raise Concerns

There are several proposals in the Staff Concept Paper that raise concerns. The first is the proposal for dynamic hourly capacity charges for the proposed Agricultural Demand Flexibility Pilot.[12] Properly designing demand charges so that they do not create cost shifting among different customer classes is complex and is a matter for a general rate case, not a rulemaking. The Staff Concept Paper proposes to include a provision to hold PG&E harmless for any difference in cost recovery between the experimental rate's charges and the otherwise

[10] Greenhouse gas emissions for diesel is 161.3 pounds of CO_2 per MMBtu versus 117.0 pounds of CO_2 per MMBtu for natural gas. Frequently Asked Questions—U. S. Energy Information Administration, 8/26/21, https://www.eia.gov/tools/faqs/faq.php?id=73&t=11. Powerplants burning natural gas emit fewer particulates, i e., PM-10, than do backup generators.

[11] The emissions controls for nitrogen oxides is much more stringent for existing powerplants than for backup generators.

[12] Staff Concept Paper at 8-9.

applicable tariff, which ensures that cost shifting will occur since any shortfall will be passed on to other bundled customers through the Energy Resource Recovery Account (ERRA). It is other customers, not PG&E, who are at risk.

CLECA is also concerned about expansion of the Demand Resource Auction Mechanism (DRAM)[13], which is still a pilot whose success remains questionable.[14] While the Staff Concept Paper does include conditions for participation to try to avoid past challenges with the pilot (e.g., penalties for shortfalls in capacity shown on supply plans, avoidance of shifting customers among resource IDs, etc.) the reality is that DRAM has not evolved beyond the pilot stage. PDR resources should be utilized prior to RDRR, so PDRs should bid into the day-ahead market at no more than the minimum bid for RDDR resources, which is 95% of the CAISO bid cap or $950/MWh; therefore, CLECA does not object to the proposed $900/MWh cap for DRAM and other PDRs. This would help avoid the problem identified by the CAISO's Department of Market Monitoring that PDR was not dispatched when RDRR like BIP was dispatched in 2020.[15]

Regarding expanded eligibility of the ELRP to residential customers, we have two concerns. The first is using a Flex Alert as a trigger in the day-ahead market, since Flex Alerts do not always lead to capacity shortages and $1000/MWh payments could be made for load reductions that are not needed.[16] The second is the assumption that there is a "simple" baseline that can be used to pay for load reductions verified by meter data. The issue of calculating a correct baseline is complex because finding similar historical usage can be difficult and there are

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[13] Staff Concept Paper at 6-8.
[14] Energy Division's Evaluation of Demand Response Auction Mechanism, Final Report, January 4, 2019 at 83, 85-87.
[15] DMM Report on System and Market Issues August and September 2020, dated November 24, 2020, at 56.
[16] Some are suggesting the ERLP payment be increased to $2,000/MWh.

concerns about possible manipulation to inflate a baseline. It is not clear that the utilities have either the ability to either create such a baseline or to track usage changes for millions of customers. These measurement deficiencies could lead to overpayments to participants, which would drive up the overall program cost.

VI. Conclusion

This concludes our opening testimony.

Attachment A: Qualifications of Catherine E. Yap

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Q1. Please state your name and business address.

A1. My name is Catherine E. Yap and my address is Barkovich & Yap, Inc., P.O. Box 11031, Oakland, California 94611.

Q2. Please state your qualifications to offer this testimony.

A2. I am a principal in the firm of Barkovich & Yap, Inc., and have been consulting in the utility regulatory area for over thirty years. During this time, I have directed and/or performed major examinations of cost-of-service requirements, allocation, rate design, and customer bill effects for electric, natural gas, and solid waste utilities. I have testified on numerous occasions before the California Public Utilities Commission (Commission) and in civil proceedings. I have consulted internationally on issues related to natural gas industry structure and marginal cost allocation and rate design.

Prior to this, I was employed for nine years by the Commission. Most recently, I was responsible for managing the Energy Rate Design and Economics Branch of the Public Staff Division (PSD). This branch was responsible for developing cost of service, rate design, and economic studies, such as sales forecasting and productivity assessment, for both electric and gas utilities. Members of the branch were responsible for presenting expert testimony, developing cost of service studies, and designing unbundled rates for the natural gas utilities during the Commission's extensive hearings on gas industry structure and rate design implementation. During this time, I participated extensively in the formulation of policy regarding the appropriate structure for the natural gas industry in California.

Previously, I was the Supervisor of the Gas Supply and Requirements Section of the Fuels Branch of the PSD. I was responsible for directing, and in some cases performing, advanced technical studies that evaluated California gas utility operations and associated contracts, investments, and expenses. I also acted as the highest level technical representative of the Commission on natural gas matters and was involved in numerous negotiated settlements involving natural gas pipelines, distribution utilities, producers, and state and federal regulatory agencies.

Prior to that, I was a staff economist in the Policy Division acting as a consultant to the Executive Director and to various Commissioners. I also testified on numerous occasions as an expert witness regarding a variety of technical, economic, and financial matters related to electric and natural gas utilities.

I have a B.A. in chemical physics from the University of California at Santa Cruz, and a M.S. in Energy and Resources from the University of California at Berkeley. I have also taken course work in finance, accounting, and organization theory from the University of California, Extension, and Golden Gate University.

Q3. What testimony are you sponsoring in this proceeding?

A3. I am jointly sponsoring the Testimony of Catherine E. Yap and Paul D. Nelson on Behalf of the California Large Energy Consumers Association.

Q4. Was this material prepared by you or under your supervision?

A4. Yes, it was.

Q5. Insofar as this material is factual in nature, do you believe it to be correct?

A5. Yes, I do.

Q6. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A6. Yes, it does.

Q7. Do you adopt this testimony as your sworn testimony in this proceeding?

A7. Yes, I do.

Q8. Does this conclude your qualifications and prepared testimony?

A8. Yes, it does.

Attachment B: Qualifications of Paul D. Nelson

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Q1. Please state your names and business address.

A1. My name is Paul D. Nelson. My business address is Barkovich & Yap, Inc., P. O. Box 11031, Oakland, CA, 94611.

Q2. Briefly describe your present responsibilities at Barkovich & Yap, Inc.

A2. I provide expert services on regulatory matters at the California Public Utilities Commission, which include addressing ratemaking, demand response, resource adequacy and reliability. I also provide expert services on related matters before the California Independent System Operator and California Energy Commission.

Q3. Briefly describe your educational background.

A3. I have a Master's Degree in Economics from Claremont Graduate University and a Bachelor's of Arts Degree in Economics from University of Southern California. I have a Certificate in Project Management from University of California, Irvine.

Q4. Briefly describe your professional background and experience.

A4. I have over 25 years of experience in utility ratemaking, development of cost effectiveness methodologies, and reliability planning. For Southern California Edison (Edison), I developed and testified on generation, transmission, distribution, and customer marginal costs for the purposes of revenue allocation and rate design. At Edison, I developed demand response cost effectiveness methodology, many of the aspects of which were incorporated into Environmental and Energy Economics development of a demand response cost effectiveness protocol adopted by the California Public Unities Commission. At Edison, I worked in the Resource Economics group and performed studies on Planning Reserve Margin, Loss of Load Expectation, and Effective

Load Carrying Capability. At Edison, I was a Senior Regulatory Advisor and for five years I represented Edison at the California Independent System Operator in stakeholder initiatives on electric market design and governance of the Energy Imbalance Market.

I am on the organizing committee of the Rutgers University's Center for the Research in Regulated Industries annual Advanced Workshop on Regulation and Competition. I have written and presented papers at the workshop on marginal cost methodologies, loss of load expectation, planning reserve margin, transmission cost ratemaking, and a case study of the Energy Imbalance Market.

Q5. What testimony are you sponsoring in this proceeding?

A5. I am jointly sponsoring the Testimony of Catherine E. Yap and Paul D. Nelson on Behalf of the California Large Energy Consumers Association.

Q6. Was this material prepared by you or under your supervision?

A6. Yes, it was.

Q7. Insofar as this material is factual in nature, do you believe it to be correct?

A7. Yes, I do.

Q8. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A8. Yes, it does.

Q9. Do you adopt this testimony as your sworn testimony in this proceeding?

A9. Yes, I do.

Q10. Does this conclude your qualifications and prepared testimony?

A10. Yes, it does.