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Comments on the Load Management Workshop Docket Number 19-OIR-01, Load Management Rulemaking

Additional submitted attachment is included below.

Comments on the Load Management Workshop
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The California Large Energy Consumers Association (CLECA)[1] submits these comments in Docket 19-OIR-01 on the Load Management Workshop held on January 14, 2020, pursuant to the notice extending the deadline for comments to January 24, 2020.

I. INTRODUCTION

CLECA's participation in the Load Management Workshop is driven by its members' concern about high rates, as well as electric service reliability. A critical concern for CLECA is how the State's goals regarding greenhouse gas emissions and renewable portfolios are balanced against concerns about ratepayer costs and reliability of the electric grid. CLECA supports California's climate goals, but we are concerned about costs – since industrial customers compete in out-of-state and international markets, they cannot just pass higher electricity costs along to their customers. Thus, the level of electricity rates is extremely important to the viability of industrial businesses in California. Electric rates impact the State's climate goals, because keeping the production of cement, steel, minerals, industrial gases, and beverages in

[1] CLECA is an organization of large, high load factor industrial customers of Southern California Edison Company (SCE) and Pacific Gas and Electric Company (PG&E); the members are in the cement, steel, industrial gas, pipeline, beverage, cold storage, and mining industries and share the fact that electricity costs comprise a significant portion of their costs of production. Some members are bundled customers, others are Direct Access (DA) customers, and some are served by Community Choice Aggregators (CCAs); a few members have onsite renewable generation. CLECA has been an active participant in Commission regulatory proceedings since 1987, and all CLECA members engage in Demand Response (DR) programs to both promote grid reliability and help mitigate the impact of the high cost of electricity in California on the competitiveness of manufacturing. CLECA members have participated in the Base Interruptible Program (BIP) and its predecessor interruptible and non-firm programs since the early 1980s.

California enables their manufacture where energy is cleaner, and avoids additional emissions associated with transportation from out-of-state facilities. Since California seeks to avoid greenhouse gas leakage in the electric energy sector as part of its climate change policy, it should also be concerned about leakage from critical industries moving outside California. A key issue in this docket is how the State's broader goals for meeting clean energy targets are best managed through well designed cost-based rates.

As will be explained in more detail, CLECA has the following comments regarding load management strategies:

- Rates should follow marginal cost rate design principles to encourage usage during the time of excess renewable power; otherwise, there is the risk of sending a signal for too much demand during low-generation-cost periods which could lead to cost increases related to distribution service
  - Excess incentives can result in requests for grandfathering of outdated time-of-use periods, as has occurred for certain tariffs encouraging the use of renewable energy or mitigation payments (e.g., for customers on RES-BCT) to compensate for investments that may no longer be cost effective should future rate design change
- Demand charges are appropriate cost-based rate elements; refinements are in process in investor-owned utility (IOU) rate design proceedings to develop more accurate cost-based time-related rates
- The deployment of smart meters allows for more accurate and granular cost-based rates for all customers
  - For example, rates could be structured to discourage simultaneous EV charging when it would be harmful to the distribution system
- Encouraging too much demand during periods of excess generation could lead to a higher cost of service if the demand triggers the need for additional investment in the distribution system (rates should not ignore distribution impacts)
  - For example, businesses and residential customers with multiple electric vehicles should face rates that encourage them to charge sequentially, not simultaneously
- Recommendations for more localized generation prices contradict prior FERC review of the issue, which found the implementation costs far exceeded the benefits
- SCE's two-part real time pricing proposal is conceptually interesting
- The conclusion in the CEC staff presentation, that unmanaged electric vehicle charging is superior to an approach based on time of use rates, uses renewable curtailment as the metric when it should use cost; using cost as a metric shows time of use pricing is superior to unmanaged charging

II. COMMENTS

A. Electricity Rates Should be Based upon Marginal Cost, Which Will Provide the Proper Price Signal

The California Public Utilities Commission (CPUC) has adopted the use of marginal cost in ratemaking since 1981.[2] Under economic theory, setting the price at marginal cost sends the proper price signal for the customer to either consume additional energy or value the savings that occur from consuming less energy.[3] For the customers of investor owned utilities (IOUs), time of use (TOU) rates have been mandatory for commercial, industrial, and agricultural customers, and will soon become the default rate for residential customers.[4] For Southern California Edison (SCE), Pacific Gas and Electric (PG&E), and San Diego Gas and Electric (SDG&E), CPUC decisions have adopted the design of TOU rates, which already reflect data showing that the marginal cost of energy is no longer highest during the afternoon. The investor-owned utility on-peak prices are now 4-9 pm, except for certain customers that are eligible for grandfathering. New off-peak prices encourage shifting of load to spring and summer late mornings and early-to-mid afternoons. These new TOU periods send customers appropriate price signals based on the current cost structure, or will send them when the default rates go into effect.

The implementation of policy objectives, including through poor rate design, can lead to unintended consequences, rendering those rates no longer cost-based. The success of the State's solar development policies resulted in a reduction of the market value of energy during the late morning and early-to-mid-afternoon, and a relative increase in the market value of energy after the decline of solar output when other resources are required to serve load. This led to marginal costs that are higher later in the day and lower during the period of solar output, which led to revised TOU periods.

For example, in the case of customers using the Renewable Energy Self-Generation Bill Credit Transfer (RES-BCT)[5], the change in marginal costs and TOU periods negatively affected those customers when the value of the credit for solar output declined along with the marginal costs. To preserve the benefits for these governmental customers, under a settlement agreement in SCE's rate case, RES-BCT customers were not just offered a grandfathered rate based on the old TOU periods, but were also provided a mitigation payment to ameliorate the impact of the changing TOU periods.[6] Thus, grandfathering these customers will continue to send the wrong marginal cost price signal until the grandfathering period expires. The grandfathering also

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[2] CPUC D91749, March 3, 1981 (OII 67) at 2.

[3] Price cannot be set to only marginal costs, because due to the large amount of fixed costs, the utility will not be able to recover its revenue requirement. In addition, for some rate schedules, such as residential, the practice has been to use only usage measurement without considering peak demand cost impacts, which reduces the ability to send the proper marginal price signal to customers.

[4] CPUC D. 15-07-001 and D. 17-09-036.

[5] The RES-BCT program allows local governments and college campuses to generate energy from a central location to offset usage at other locations, a form of virtual net metering.

[6] CPUC D. 18-11-027 (SCE TY2018 GRC Phase 2) at 60.

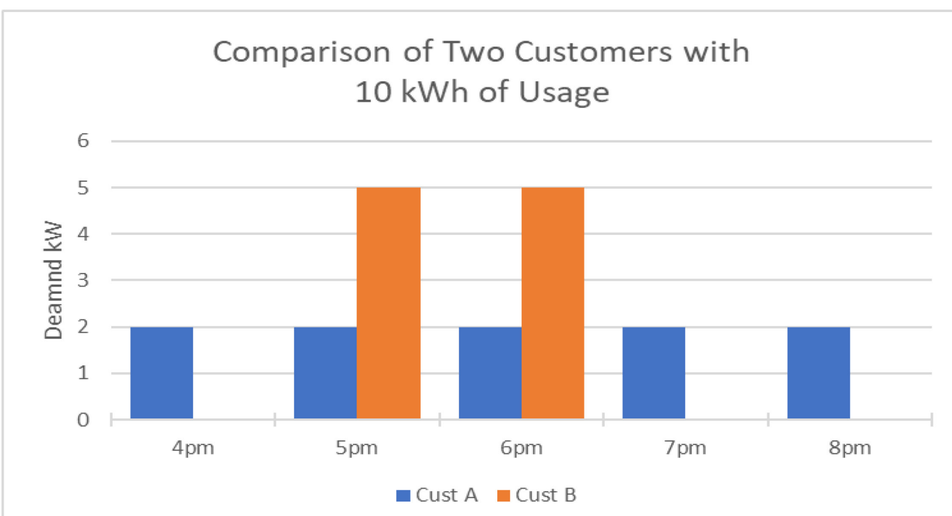
results in a revenue shortfall.[7] The revenue shortfall and mitigation payments have to be picked up by other customers.

Rates based upon marginal costs provide the proper incentive to choose efficient levels of power consumption during the various hours of the day. These rates should also be updated as underlying costs change. Proper rates should help shift usage into the daytime period when energy is abundant; however, increased usage may over time increase the marginal cost of energy in these hours in the future. The CPUC determined that TOU periods would not be changed more frequently than every five years, but the prices within those TOU periods are subject to revision. The design of the future TOU periods may change if the cost structure changes. Improved communication with customers will help them better understand how rates may change in the future, so that they can take that risk into account in their investment decisions.

1. Peak demand charges can appropriately recover costs and send the proper price signal

The cost drivers for electric service are energy (kWh), time-related peak demand (peak kW), non-time-related (non-coincident) peak demand (kW), and per customer charges. The peak demand charges apply to both generation and delivery services of transmission and distribution. Some parties have claimed that peak demand charges are inappropriate, or that they encourage inappropriate rate arbitrage. We disagree, as there is a cost justification for demand charges.

Consider two customers with 10 kWh of usage over a five-hour period. Customer A uses 2 kW over the five hours, and customer B uses 5 kW over two hours as shown in the figure below.



[7] For grandfathered customers on the old TOU rates, the evening rate is less than the current costs, and the value for daytime energy is also overstated, so the combination of the two impacts will result in revenue shortfall.

While both customers use the same amount of energy, customer B causes more stress to the system because its demand is 2.5 times the demand of customer A. Higher demand requires more generation and distribution capacity. Because it costs less to serve customer A than customer B, it is inappropriate to bill both customers using only energy rates, because under this rate scheme the two customers would pay the same amount. Instead, pricing should incorporate a demand charge, because it properly reflects the cost difference. A combination of time-related and non-time-related demand charges will best recover the cost to provide that capacity, because capacity costs are a mixture of generation and distribution. Since distribution capacity cannot be utilized by other customers on a different circuit, it is generally appropriate to reflect a significant portion in non-coincident demand charges. Alternatively, it may be appropriate to recover some portion in locally coincident charges, although the local demand on the distribution system may shift over time.

Dr. Severin Borenstein suggests that customers will use technology to perform regulatory arbitrage to manage demand charges.[8] While that is a legitimate concern if it simply allows the customer to avoid the rate without any reduced cost to the system, the problem is poor rate design rather than the existence of a well-designed demand charge based upon marginal cost. Consider the prior example; if customer B cost-effectively installs equipment to reduce its peak demand to avoid paying the cost-based demand charge, then there is a benefit to the customer through a lower bill; there may in the future be a benefit to the electric system if future capital investment can be avoided.[9] However, the costs of the existing distribution system must still be recovered.

Dr. Borenstein's statement that the "sloppy ratemaking of the past depended on customers not being responsive" is not a universal conclusion for all customer types.[10] For the IOUs, since the 1980s industrial customers have been paying a rate design based upon marginal cost that reflects cost drivers consisting of time-related energy charges, time-related peak demand, non-time-related peak demand, and a fixed per customer charge. After the energy crisis in 2000-2001, the requirement for time-related energy charges was expanded to all non-residential customers with peak demands above 200 kW. TOU rates are now used for all non-residential customers, and will soon be the default rate for residential customers.[11] In addition, the CPUC has required the IOUs to improve and justify their non-time-related demand charges. Recent decisions call for increased emphasis on time-related demand charges for larger non-residential customers. Therefore, while non-residential customers have had rates designed to encourage price responsiveness, it is only relatively recently that time of use energy charges have been deemed appropriate as the default for the residential sector.

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[8] Borenstein, Severin. The Value of Economic Pricing in a Low-Carbon Electricity System. Presented at the Load Management Workshop on January 14, 2020. Slide 4.

[9] The reduction in this customer's peak demand contributes to the deferral of future investment by allowing additional customer load growth on the circuit.

[10] Borenstein, Severin. The Value of Economic Pricing in a Low-Carbon Electricity System. Presented at the Load Management Workshop on January 14, 2020. Slide 14.

[11] D. 1507001 and D. 1709036.

2. The installation of smart meters will allow more accurate marginal cost-based rates to more customers that seek to charge electric vehicles

California wants to electrify the transportation sector by the use of electric vehicles (EV). Consider the behavior of a household or business with multiple EVs. Should those customers charge simultaneously when they return home and charge overnight, or should they charge sequentially? For the residential and small commercial rate classes, there is no disincentive for simultaneous charging. If simultaneous charging is concentrated in geographic areas, such as wealthy communities, then it will likely require increased distribution infrastructure, which increases the cost of electric service, likely in turn discouraging electric vehicle adoption.

However, with the ability to measure hourly usage due to smart meters, it would be possible to develop peak demand type charges for more types of customers in order to discourage simultaneous charging. This would provide a more accurate price signal and help avoid the need for distribution system additions that would be required to accommodate inefficient charging patterns.

B. SCE's Two-Part Real-Time Pricing Rate Shows Promise, but Requires Further Refinement

At the workshop, SCE presented the concept of a Two-Part Real-Time Pricing Rate.[12] The base generation usage would be based upon historical usage, and priced at the prevailing time of use rates for the tariff; the latter would include both capacity and energy components. An incremental portion of the customer's usage would be priced based upon an energy component and a capacity adder based upon real-time conditions. The energy component would be based upon the California Independent System Operator (CAISO) day-ahead price for SP15. A capacity adder component would be triggered by an implied market heat rate which is based upon the CAISO market price and the SoCal City gate price for natural gas. SCE did not provide details on the threshold for the capacity adder trigger. The presentation also mentioned that the value of the capacity adder would also be based upon the CAISO day-ahead energy price. If the energy price is based upon the CAISO day-ahead price and the capacity adder is also based upon the CAISO price, this would appear to double count the cost of energy and any shortage value that is embedded in the CAISO prices due to scarcity. In other words, if CAISO energy prices are very high due to shortage, or due to CAISO penalty price parameters when the CAISO must relax a constraint, then we question whether it is necessary to apply a capacity adder which is also based upon CAISO prices.

SDG&E made a presentation on how to design a dynamic rate, involving several layers of base costs, distribution time-related costs, and time-related energy costs. An important point in the presentation is that distribution peaks do not always occur at the time of the system peak. Furthermore, the daytime gross peak around 4 pm does not occur at the same time as the net peak,[13] which occurs later in the evening period; the net peak is when the cost of generation is

[12] SCE, Two-Part Real Time Pricing (RTP), January 14, 2020.
[13] Net peak = Retail load – Solar – Wind

the highest. The economic benefits of shifting load to the daytime period in order to take advantage of lower cost generation may be offset by more expensive additional investment in the delivery system to accommodate the increased daytime demand. Therefore, it is important to include the appropriate marginal cost impacts to the delivery system.

Conceptually, SCE's two-part rate idea has promise, and SDG&E shows the components of a dynamic rate, but there is considerable complexity in sending the right price signal while recovering costs; the details matter. CLECA looks forward to reviewing the real time pricing proposals in future rate setting proceedings.

C. Recommendations for Retail Rates Using Finer Local Granularity Contradict Prior FERC Review, Which Found It Was Not Cost Effective

Currently, the CAISO charges for wholesale load at the default load aggregation point, which is a weighted average of the p-nodes within the aggregation point. At the January 14, 2020, workshop on Load Management, Dr. Borenstein suggested that customers should be charged for generation based upon their local (we assume p-node) price instead of the default aggregation point, in order to provide a more accurate locational price signal. In 2014, the Federal Energy Regulatory Commission (FERC) denied the CAISO's request for a permanent waiver from charging load at a more granular level, and ordered the CAISO to justify why the waiver should be permanent. The CAISO performed a cost versus benefit study of charging load at a more granular level and determined that the implementation and ongoing costs exceeded the expected benefits. The benefits were estimated at $1-3 million annually. The estimated implementation costs for fully nodal disaggregation totaled $14.6 million in one-time implementation costs, $132.6 million in capital costs, and $12.6 million annually. [14] One of the complications is that the customers connected to a p-node are not static, because they can be shifted among distribution circuits. Therefore, new metering and telemetry would need to be installed and maintained, in order to manage and track which customers are connected to which p-node at any given time period. The FERC accepted the CAISO request for the permanent waiver from more granular pricing to load. [15] Unless the benefits of pricing load at increased local granularity are found to exceed its cost, the CEC should reject this request.

D. The Conclusion that Unmanaged Electric Vehicle Charging is Superior to Responding to Time of Use Pricing is Incorrect and Misleading

Mr. Noel Crisostomo, CEC Staff, delivered a presentation on Electric Vehicle Charging Load at the January 14, 2020, Load Management Workshop. Mr. Crisostomo's presentation on Slide 3 indicated that unmanaged (i.e., undifferentiated or flat prices) electric vehicle charging resulted in less renewable curtailment than charging based upon responding to time of use (TOU) pricing. This is a misleading conclusion for several reasons. Renewable curtailment is only one factor to consider; there is also the total cost impact to the electrical system for electric vehicle charging. The same study that Mr. Crisostomo relied upon compared the total system cost under unmanaged and TOU prices and found the use of TOU pricing to be less expensive, as shown in

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[14] CAISO, Load Granularity Refinements. March 24, 2015, at 3.
[15] FERC, Acceptance of CAISO Compliance, Oct. 21, 2015 (ER02-1656-038) (ER06-615-061)

the figure below.[16] The study found "compared to unmanaged charging, TOU charging provides California $90 to $550 million in value per year".[17] While smart charging based upon a dynamic signal reflecting real-time system conditions is an ideal option, there is a cost associated with its implementation that will not be cost effective for everyone. TOU pricing is an option that can be implemented by electric vehicle owners with minimal cost or no additional cost, as many electric vehicles can be programmed to charge during specific time periods. TOU periods can offer marginal benefits at relatively low cost, whereas obtaining the benefits under smart charging will require higher costs for management and communication technology. Some customers may find the benefits of smart charging higher than its costs, but other may choose TOU rates.

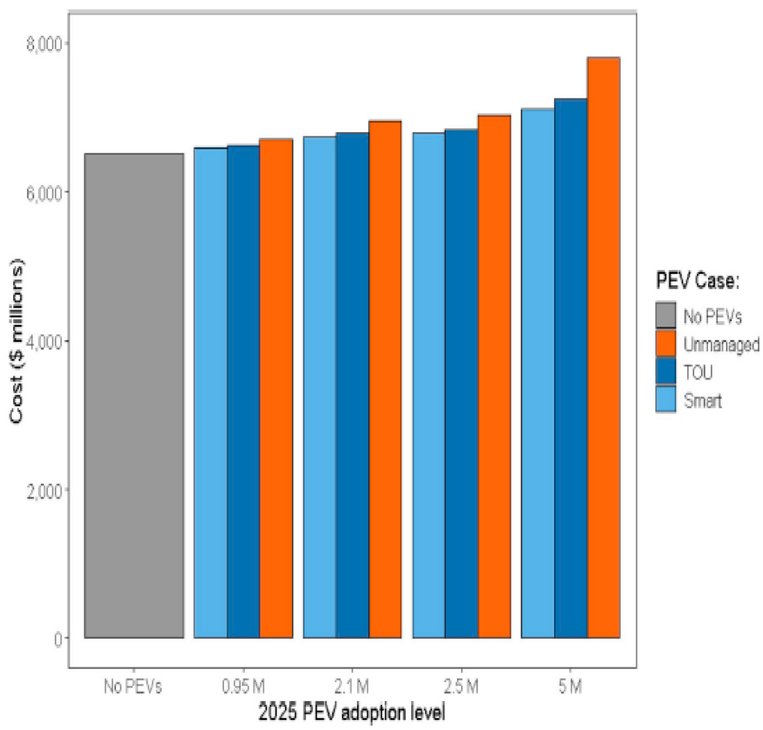

Fig. 5. Annual California total system cost. Annual total system cost for California includes the grid operating cost from generation, emissions, and net imports.

In addition, the referenced study did not develop an explicit TOU rate; it assumed that all residential charging would start between 10 pm – 2 am.[18] With new TOU pricing options offering the cheaper pricing during the daytime hours, some of this EV charging may shift to hours with abundant renewable power. This could be accomplished by customers either shifting, if feasible, their residential charging times, or charging while at work, provided the site passes

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[16] Lawrence Berkeley National Laboratory & UC Berkeley (2020), Reduced grid operating costs and renewable energy curtailment with electric vehicle charge management at 9.
[17] Lawrence Berkeley National Laboratory & UC Berkeley (2020), Reduced grid operating costs and renewable energy curtailment with electric vehicle charge management at 9.
[18] Lawrence Berkeley National Laboratory & UC Berkeley (2020), Reduced grid operating costs and renewable energy curtailment with electric vehicle charge management at 7.

through a rate that is cheaper than if they charged at home during the night. Therefore, the TOU scenario in the study may underestimate its impact on customer behavior.

As mentioned previously, it is important to prevent possible unintended consequences that electric vehicle charging can have on the distribution system if the vehicles are concentrated in a local area, and simultaneous charging occurs. This concern is particularly valid for charging at work locations when there may be many electric vehicles wanting to charge at the same time. Therefore, the use of properly designed TOU rates or smart charging options will be critical for widespread electric vehicle adoption.

III. CONCLUSION

CLECA supports cost-based electricity rates recognizing that the costs may change over time and rates must reflect this. We caution that non-cost-based rates will lead to unintended consequences, and urge that both distribution and generation-related costs be considered in the updating of the CEC's load management standards.

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