BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Microgrids Pursuant to Senate Bill 1339 and Resiliency Strategies.	Rulemaking 19-09-009 (Filed September 12, 2019)

COMMENTS OF MICROGRID RESOURCES COALITION ON THE ASSIGNED COMISSIONER'S AMENDED SCOPING MEMO AND RULING FOR TRACK 3

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Background

The Microgrid Resources Coalition ("MRC") respectfully files its comments in response to the R.19.09-009 Standby Charges Energy Division Staff Questions (the "Staff Questions") provided in conjunction with the Assigned Commissioner's Amended Scoping Memo and Ruling for Track 3 (the "Track 3 Scoping Ruling") issued as a part of the California Public Utility Commission (the "Commission") proceeding instituted in its Order Instituting Rulemaking Regarding Microgrids Pursuant to Senate Bill 1339 ("SB 1339") in the above captioned proceeding. The MRC appreciates this opportunity to assists in formulating the issues for this phase of the proceeding.

The MRC is a consortium of leading microgrid owners, operators, developers, suppliers, and investors formed to advance microgrids through advocacy for laws, regulations and tariffs that support their access to markets, compensate them for their services, and provide a level playing field for their deployment and operations. In pursuing this objective, the MRC intends to remain neutral as to the technology deployed in microgrids and the ownership of the assets that form a microgrid. The MRC's members are actively engaged in developing microgrids in many regions of the United States including many who are actively engaged in microgrid development in California.[1] MRC members have also been operating sophisticated microgrids over an extended period of time (some for over 30 years). They are at the cutting edge of microgrid technology.

The mission of the MRC is to promote microgrids as energy resources by advocating for policy and regulatory reforms that recognize and appropriately value the services that microgrids offer, while assuring non-discriminatory access to the grid for various microgrid configurations and business models. We generally support disaggregated, fair pricing for well-defined services both from the grid to microgrids as well as from microgrids to the grid. We promote community-based resilience standards and support utilities that are working toward new business models that value resilient distributed resources. We work for the empowerment of energy customers and communities.

Overview of Comments

The Staff Questions principally focus on the possibility of trading an exemption from standby charges for grid services rendered by microgrids. Microgrids have the capability of providing a wide range of grid services, as we attempt to explain below. They provide many of them without compensation, and others that they could provide are blocked by various tariff limitations. As indicated in the background above, however, the MRC generally supports disaggregated, fair pricing for well-defined services both from the grid to microgrids as well as from microgrids to the grid, and generally seeks a level playing field for microgrids. We are concerned that the suggested trade will not be based on accurate valuation of the respective services and could muffle rather than create incentives for microgrids.

The MRC has been among the voices in this proceeding calling for the elimination or reform of standby charges. Standby charges were last addressed comprehensively by the Commission in Decision 01-07-027 (July 12, 2001) in Docket R. 99-10-025 (Order Instituting Rulemaking into

[1] Members of the MRC include: Bloom Energy, Concord Engineering, Eaton, eco(n)law, Emory University, Engie, Icetec, International District Energy Association, Mainspring Energy, Massachusetts Institute of Technology, Princeton University, Reimagine Power, Resilience Plus, Scale Microgrid Solutions, Schneider Electric, Thermo Systems, University of Missouri and the University of Texas at Austin. The MRC's comments represent the perspective of the coalition and should not be construed as speaking for individual members.

Distributed Generation.) (the “Standby Decision”). At the time, California was still in the throes of an energy crisis; solar energy was in very limited use; batteries and fuel cells were not a part of the electric supply system; and PG&E argued that “there are relatively few distributed generation units connected at distribution voltage”.[2] While the Commission certainly appears to have given the matter careful thought at the time, things have changed. The MRC believes that standby charges as currently implemented do not fairly reflect utility costs related to behind the meter generation broadly speaking or related to microgrids in particular.

The Track 3 Scoping Ruling states that a microgrid exemption from cost responsibility surcharges contravenes the SB 1339[3] prohibition against cost-shifting.[4] Perhaps that is so, but there is no evidence in the record to support the statement. We believe that thoughtful cost effectiveness analysis is required on both the standby side and the microgrid services side. That, we submit, is the responsibility of the Commission, and in any event, is not within the capability of any party to provide in the three weeks allotted for this filing.

In this context, the MRC suggests that:

- The Commission fully eliminated standby charges for microgrids below 5 MW in aggregate generation capability.
- The Commission re-evaluate standby charges for all behind-the-meter (“BTM”) distributed energy resources, and that in the interim the distribution component of the Reservation Charge be eliminated for all microgrids 5 MW or larger.

We believe that these modifications reduce an improper cost shift from utilities to microgrids and are consistent with the SB 1339’s direction to the Commission to eliminate barriers to the commercialization of Microgrids.[5]

The following discussion explains our reasoning in more detail in the form of answers to the Staff questions. Throughout we reference Pacific Gas and Electric Company (“PG&E”) rate schedules by way of example. However, no specific comment on PG&E’s rates as compared with other large electric companies is intended.

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[2] Standby Decision at 12.
[3] SB 1339 (Stern 2018) https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180SB1339
[4] Track 3 Scoping Ruling at 6.
[5] Pub. Util. Code § 8371(b).

Responses to Staff Questions

A. Background and Question

1) Do you agree with the overview of standby charges provided in section A above? If not, please explain.

The description is not wrong so far as it goes but is very short on critical detail. Recently, standby rates for PG&E were substantially modified pursuant to Decision 18-08-013 (August 17, 2018) in Docket A.16-06-013 (Decision on Pacific Gas and Electric Company's Proposed Rate Designs and Related Issues) as it relates to time of use ("TOU") rates (the "TOU Decision"). Schedule SB replaced old Schedule S.[6]

B. Overarching Scoping Questions

1) Should the CPUC require the IOUs to waive or reduce standby charges for a customer operating a microgrid if specific conditions are met?
    a) If so,
        i) What are the specific conditions that should be met to qualify for a standby charge waiver or reduction?
        ii) Which standby charges should be reduced or waived, and by how much?
        iii) Please explain any additional details of how a standby charge waiver or reduction should be implemented that are necessary for the CPUC to consider.

As discussed above, the MRC suggests that:

- The Commission fully eliminated standby charges for microgrids below 5 MW in aggregate generation capability.
- The Commission re-evaluate standby charges for all behind the meter distributed energy resources, and that in the interim the distribution component of the Reservation Charge be eliminated for all microgrids 5 MW or larger.

The MRC believes that current standby charges improperly shift costs to microgrids (and to a lesser extent to other BTM resources). We discuss the basis for this conclusion at length in response to Question F. 1. below. The current charges fail to take account of diversity of resources both on the distribution system and within microgrids. In addition, standby charges have risen disproportionately to demand charges for use of the distribution system and are not based on

[6] *See*, https://www.pge.com/tariffs/electric.shtml

Commission principles of cost causation. Until more definitive studies can be conducted, we believe that elimination of the distribution portion of the reservation charge is warranted. The suggestion of a 5 MW lower limit for any charge is the same as the current limit for NEM fuel cell resources[7] and is based on the extreme improbability of the simultaneous failure of enough resources of this size in near proximity to each other to create a significant disturbance on the system.

b) If not, why not?

2) What are potential consequences of waiving standby charges? Please quantify wherever possible.

a) If reducing or eliminating standby charges for microgrids would facilitate the installation of new microgrid capacity that would create benefits for non-microgrid customers, please detail how, and quantify the benefits.

The following discussion is based on the ability of microgrids to act as their own balancing authority in island mode and their corresponding ability to manage their load, generation, exports and imports in grid connected mode. Microgrids also typically have internal generation diversity. Some of the services can also be provided by non-microgrid DER though in some cases with less reliability or precision.

- Microgrids simply take load off the system. California provides subsidies for energy efficiency projects that do this.[8] They displace the need for resource adequacy whether or not they are qualified to be paid for it. They take load off their individual feeder which in effect provides non-wires alternative space on the feeder. The value of this is idiosyncratic but is likely to be directly proportional and offsetting to the difficulty of providing standby service on the feeder.
- Microgrids reduce volatility and the need for ramping capability to manage the duck curve. They exercise demand management on a full-time basis (they may also provide demand response, but that is a distinct service).
- Microgrids paid for with private or community investment reduce costs to other ratepayers including:
    - The cost of meeting state renewable energy goals. Where space is available microgrids will typically include solar and batteries along with fuel-based

[7] *See*, PG&E web page "Net Energy Metering for Fuel Cells", https://www.pge.com/en_US/for-our-business-partners/interconnection-renewables/net-energy-metering/nem-for-fuel-cell-generators.page
[8] As discussed elsewhere in this proceeding, microgrids are instead charged for the privilege of doing this.

generation and may use renewable fuel sources as well. Fuel resources will typically be far more efficient than the current grid average, and SB 1339 limits their emissions profiles (which may be further limited by local air-quality approvals). Many microgrids are entirely solar and batteries. Any renewables installed where the ratepayers do not pay (e.g. through PPA rates) for the capital investment benefits all ratepayers.

  - The cost of increasing generation capacity to electrify the transportation system and more of the built environment. The effect is the same as above.

  Both of these benefits require taking a dynamic rather that a static view of cost effectiveness. This has not been the Commission's approach to date, but we suggest that it should be.

- Microgrids provide resilience. The "value of resilience" will be the subject of further examination in Phase 4 and will not be briefly resolved. Clearly the resilience of hospitals, schools and other critical facilities have value for other ratepayers, and microgrids have an excellent track record of providing that resilience.[9] In anecdotal reports from our members and members of our member organization IDEA, their microgrids in Texas all survived the most recent winter storm and kept operating. However, that value is not captured in payments or avoided costs within the grid.

In addition to the benefits microgrids already provide, they can provide many more if enabled.

- The MRC takes its definition of resilience from the landmark 2017 study by the National Academies of Sciences, Engineering, and Medicine, Enhancing the Resilience of the Nation's Electricity System,[10] which distinguishes between reliability – the ability to withstand disruption and keep operating in normal mode – and resilience – the ability to rapidly reconfigure and/or repair the system in response to a failure. Microgrids can play a key role in grid resilience *if* utilities invest in sectionalizing the distribution system and in distributed semiautonomous controls that allow microgrids to support local sections of the grid. This is a lower cost (to ratepayers) alternative to diesel at substations. In this connection we also recommend a recent study out of Florida that uses smart meter

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[9] See Exhibit B, Examples of Microgrid Resilience.

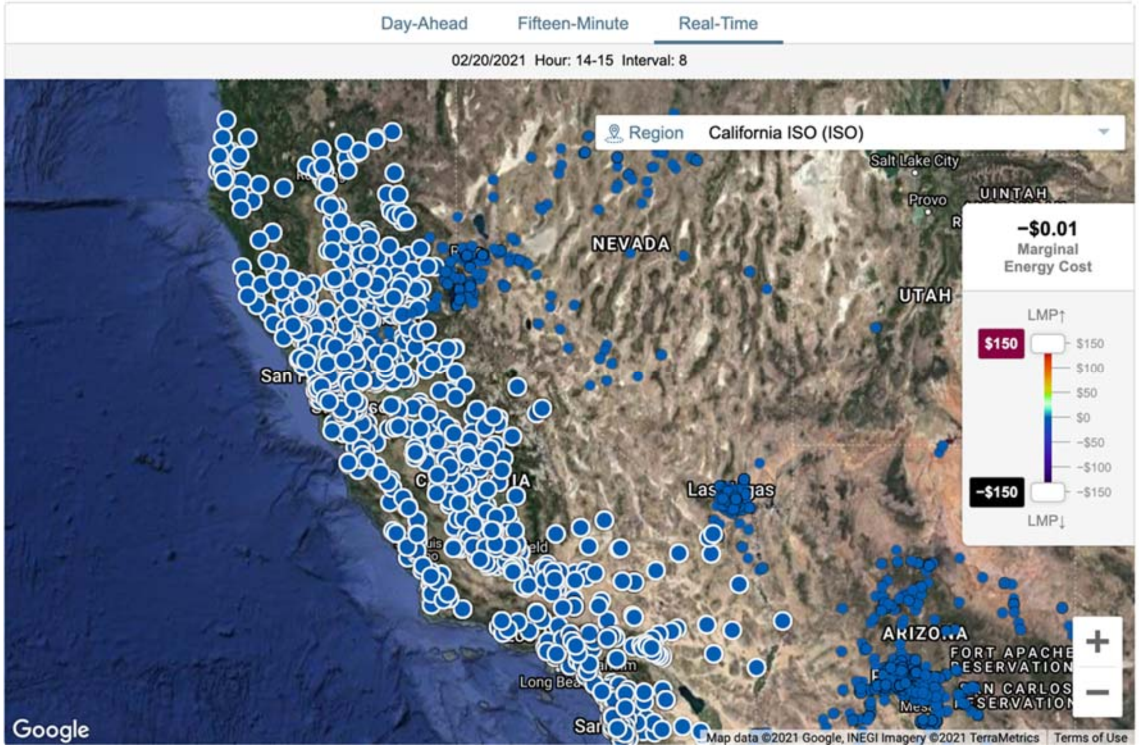
[10] The study is available at, https://www.nationalacademies.org/news/2017/07/enhancing-the-resilience-of-the-nations-electricity-system

installations as a proxy for the degree of utility investment in the visibility that is a necessary component of resilience and concludes that these investments have substantial benefits for ratepayers.[11]

- Many of the benefits that microgrids provide in other jurisdictions comes from their ability to export power or provide other grid services. Exports of power at market rates (e.g. the wholesale rates determined by CAISO) can only help ratepayers by providing more competition. In other RTO markets our members provide frequency regulation, demand response and capacity with the same beneficial effect on wholesale rates. However, as we have discussed elsewhere in the proceeding the interconnection issues for wholesale sales have generally not been addressed, and sales to the utilities are generally impossible for non-Rule 21 eligible resources.
- Microgrids (and other BTM generation) cannot access real wholesale power purchase rates. PG&E's recently revised TOU rates are blocked into peak, partial peak, off peak and spring "super off peak" time blocks for summer, winter and spring periods – not actually tracking wholesale prices. It is hard for a microgrid to deliver the services that it could when it can't respond to detailed price signals. As shown in the screenshot below, at around 2:30 Saturday afternoon, February 20, a spot check of the CAISO website revealed that the wholesale price was negative everywhere in the state. In an efficient system, every battery on the grid should have been charging. But it would have cost over 10 cents per MWh to do so under the PG&E's E-20 tariff (then still in effect). Further, restrictions on charging NEM batteries with grid power would have completely prevented some of them from doing so. Finally, the non-NEM batteries may have had no way of exporting.

[Illustration next page.]

[11] Cheyney O'Fallon, Avi Gopstein, NIST Publications, Quantifying Operational Resilience Benefits of the Smart Grid (2021), *available at,* https://www.nist.gov/publications/quantifying-operational-resilience-benefits-smart-grid

- 

b) If reducing or eliminating standby charges for microgrids would result in a cost shift prohibited by SB 1339, please detail how, and quantify the cost shift.

As discussed above and at greater length below in response to Question G. 1., the MRC believes that the cost shift goes the other way. BTM resources are paying more than their fair share for the distribution system in standby charges.

C. Existing Rate Schedule Features (directed to Utilities and Developers)

1) Describe the existing ways a customer generator or microgrid project can take service that would not obligate the customer to incur a standby charge, citing for reference to the exact applicable CPUC authorized tariffs, rates, or rules. Are there existing exemptions from standby charges that could apply to certain microgrid use cases? If so, describe.

The Commission and its staff are uniquely positioned to answer this question. In our experience the following exemptions are relevant:

- Net Energy Metering resources.
- Partial offset under PG&E Schedules B-19 and B-20

2) What obstacles prevent customer generators or microgrid project developers from using the customer provision of physically assured load reduction (for one example, refer to PG&E

Electric Sample Form No. 79-1050)? Would options such as providing physical assurance through reliable firmware settings and less expensive protective relay equipment reduce those obstacles?

The MRC believes that the physical assurance program is inefficient and uneconomic. It requires substantial expenditure on unnecessary equipment that may limit the performance of the microgrid in other conditions. In addition, it ignores true hardship. If hospital generation fails, cutting off its power is a poor solution. In the 2001 Standby Decision the Commission heard suggestions for a customer selected level of backup supplemented by a high emergency rate if it requires more.[12] This and other creative solutions are worth further consideration.

3) If a microgrid project developer or customer generator account signs a physical assurance agreement, will they be eligible to participate in the base interruptible program,[1] emergency load reduction program[2] or other demand response programs, by promising to island when called and continuing to serve their own customer microgrid load?

D. Questions for Developers

1) Please list examples of customers who were presented with a project cost estimate that declined to move forward in past five years based on concerns of economic feasibility, where it would be reasonable to expect that a complete elimination or partial reduction in standby charges would have changed the customer's decision. Please include quantitative details on the project cost, customer's economic feasibility threshold, and standby charges involved for each example.

Please see Exhibit A for a description provided by Carol Denning, CEO of MRC member Energy Pathways, of a project that was redesigned, stalled, and is currently uncertain of completion due to standby and departing load charges.

2) Please provide quantitative examples of hypothetical but realistic scenarios demonstrating how standby charges affect project economics and/or company profitability.

The following chart is taken from <u>The Effect of Departing Load Charges on the Costs and Benefits of Combined Heat and Power</u> prepared by ICF International for the California Clean DG Coalition in 2013 (the "ICF Report"). It shows the effect for 3 typical projects of PG&E's then

[12] 2001 Standby Order at 52.

standby and departing load charges on the projects' delivered cost of energy – around a 30 percent increase for the smallest project size.[13] As shown below in our response to Question G. 1., the standby charges have increased disproportionately since then.

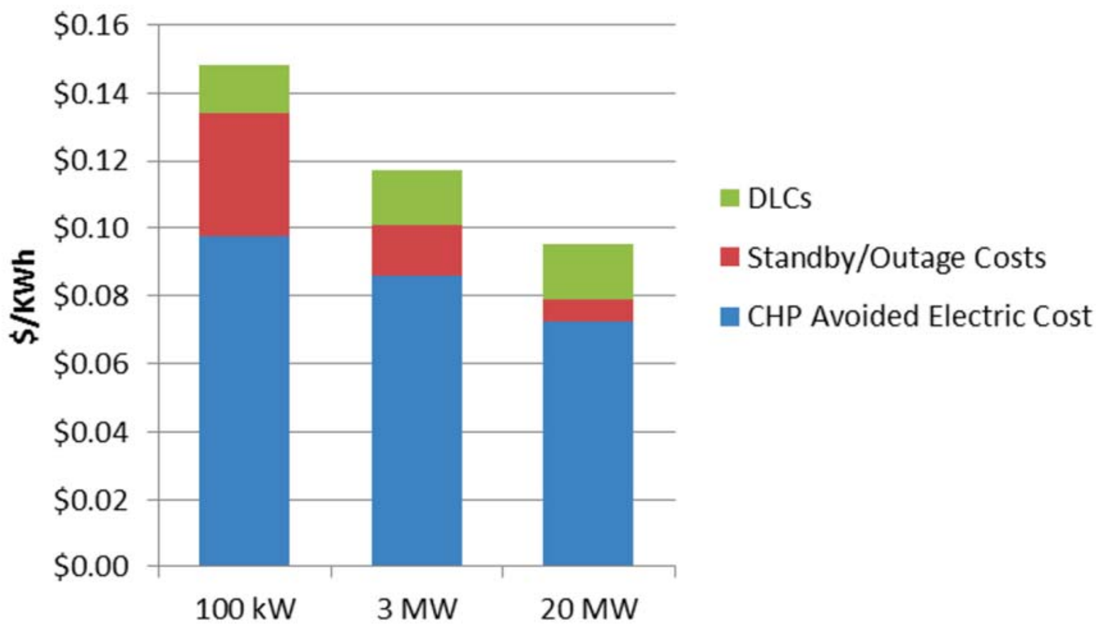


Figure 2. PG&E Retail Rates and CHP Unavoidable Costs

3) Provide examples of customers who have contracted for a physical assurance agreement and describe the terms, conditions, costs, and experience using physically assured load reduction in lieu of paying standby charges.
4) Please provide quantitative examples of realistic scenarios demonstrating how standby charges affect project economics and company profitability.
5) What obstacles prevent customer generators or microgrid project developers from shifting fuels to renewable fuels in order to become eligible for current standby exemptions or utility rate schedules limited to fully renewable and/or lower carbon intensity technologies?

Many of our members' technologies are capable of generating power from renewable or non-carbon fuels such as biogas or hydrogen. Bioenergy resources that are produced onsite at certain facilities, such as a wastewater treatment plant or dairy, may serve as the renewable fuel backbone

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[13] ICF Report at 7. *Available at,* https://bcse.org/images/BCSEinAction/impact%20of%20dlcs%20on%20chp%20economics%20final%20report%20clean%20copy%20r4.pdf

for some microgrids. The production of onsite RNG may still not be enough to meet the energy needs of a given facility. If a facility that is looking to install a microgrid must source renewable fuel from offsite, the options for procuring enough fuel for power generation are currently limited, though we anticipate future growth.

One barrier in the transition towards cleaner fuels in the power sector is the availability of supply in the market. There is a robust market for renewable fuels in California. The demand is largely concentrated in the transportation sector driven by the California Air Resources Board's Low Carbon Fuel Standard (LCFS) program.[14] The LCFS program and the U.S. Renewable Fuels Standard both value the externalities of carbon and generate credits for producers of renewable fuels. Those credits are most often purchased by the California trucking fuel and transportation sectors to offset the use of diesel and other heavy duty vehicle fleets.[15] While RNG can be secured for power generation, the market forces driving supply and demand are dominated by the transportation sector because of the robust incentives offered by the LCFS and RFS programs. While not an insurmountable obstacle for power generation technologies, nonetheless, it is a barrier that the Commission should acknowledge when assessing the availability of renewable fuels today and considering requirements for renewable fuels.

6) Please estimate the forecasted market for microgrids under the following situations by completing the table below listing identifying categories of market sectors or critical facility types defined by D.19-05-042. Please cite data sources where applicable:

This would require a major economic study, which we believe the Commission should undertake. In Docket R18-12-005 the Commission required utilities to create lists of critical facilities. The following table lists those categories along with a few others that almost certainly belong. It also gives the number of California facilities in each category to the extent we have determined it so far from publicly available sources (with a focus on which are likely to be large enough to economically support a microgrid):

[14] California Air Resources Board Low Carbon Fuel Standard https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard/about

[15] *The Feasibility of Renewable Natural Gas as a Large Scale, Low Carbon Substitute* Prepared for the California Air Resources Board and the California Environmental Protection Agency by UC Davis Sustainable Transportation Energy Pathways Program, pg. 13 https://ww2.arb.ca.gov/sites/default/files/classic/research/apr/past/13-307.pdf

Type of Facility	Number of CA Facilities
Police Stations	346
Fire Stations	802
Emergency Operations Centers	
Hospitals	341
Skilled Nursing Facilities	
Nursing Homes	1230
Blood Banks	
Schools	10,000
Public and private Utility Facilities Vital to Maintaining or Restoring Normal Service	
Drinking Water Plants	2895 (including 700 that are medium to very large)
Wastewater Treatment Plants	900
Communications Carrier Infrastructure	
Other Facility Types	
Airports (with scheduled flights)	24
Major Ports	11
Military Bases	32

This doesn't cover colleges and universities, grocery stores, gas stations or other transportation infrastructure. By any measure the need is very large. Moreover, none of these facilities sustains economic activity such as industrial and manufacturing facilities or protects them where unexpected shutdowns can result in explosions and toxic releases as occurred in hurricane Harvey in Texas.[16] The market for private facility microgrids is, of course, vastly larger.

- Total megawatts of microgrid generation capacity (excluding storage) that would be financially viable in California if standby charges were waived;
- Total megawatts of microgrid generation capacity (excluding storage) that would be financially viable in California if standby charges are not modified from their present form.

E. Resource Eligibility Questions

1) Please indicate which resource types below should be granted a partial or complete waiver and explain why (multiple answers are acceptable).

[16] *See*, Explosions and Black Smoke Reported at Chemical Plant, New York Times, (August 30, 2017), *available at,* https://www.nytimes.com/2017/08/30/us/hurricane-harvey-flooding-houston.html

a) No additional resource types, i.e. standby charge exemptions limited to:
   i) Resources that qualify for exemptions or waivers in existing CPUC authorized rate schedules, with no additional revisions;
   ii) Resources that qualify for exemptions or waivers through implementation of physically assured load reduction and a physical assurance agreement executed with the utility;
   iii) Only renewable electrical generating facilities as defined by the California Energy Commission Renewable Portfolio Standard Eligibility Guidebook and the Overall Program Guidebook;
   iv) Backup diesel generators that serve health care facilities as defined by Health and Safety Code 41514.1 (referenced in P.U.C. 8371(d));

b) Natural gas generators that comply with emissions standards adopted by the State Air Resources Board pursuant to the distributed generation certification program requirements of Section 94203 of Title 17 of the California Code of Regulations, or any successor regulation (referenced in P.U.C. 8371(d));

c) Resources that meet some other set of criteria (please explain);

d) No limits other than meeting the criteria defined elsewhere that are not related to resource eligibility.

All of the foregoing resources are expressly eligible to receive compensation under a microgrid tariff as required by SB 1339.[17] We do not view eliminating or reforming standby charges that improperly shift costs to microgrids as granting compensation, but, in any event, there no justification under SB 1339 for making distinctions. SB 1339 requires the Commission to eliminate barriers for all microgrids as defined, not some of them.

California currently has a broad array of policies aimed at decarbonizing its economy. These include measures directly affecting the electricity sector including an economy wide cap and trade program,[18] a renewable portfolio standard, and a variety of technology specific program such as NEM and SGIP legislation and the Waste Heat and Carbon Reduction Act[19] that favor certain types of renewable energy and storage, along with fuel cells and cogeneration. It also has broad policy objectives for deployment of renewable energy and decarbonization, some of which, such as the mandate to move to emissions free vehicles, will greatly affect the electric sector. Resource adequacy is required to be firm supply, which tends to favor natural gas assets.[20]

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[17] Pub. Util. Code § 8371 (d).

[18] Health and Safety Code § 38500, *et seq*. While the result is subject to a range of factors, back of the envelope calculations by MRC member engineers suggest that natural gas generators larger than 10 MW will typically exceed the statutory minimum of 25,000 $MTCO_2e$ per year and be subject to program mandates and generators as small as 5 MW may be included depending on their efficiency and other factors.

[19] Pub. Util. Code § 2840, *et seq.*

[20] Natural gas assets constituted roughly two thirds of all RA assets according to the Commission's September 2019 report

The MRC would support studies that quantify the contributions of microgrids to reducing (or increasing) CO_2 emissions. However, given the explicit statutory guidance on resources eligible for a microgrid tariff, and the evident (albeit less than fully quantified) benefits of microgrids across a range of policy objectives, the MRC suggests that it would be unwise for the Commission to try to second guess the statutory standard.

2) If CPUC were to allow nonrenewable project resources to be eligible for a waiver or reduction in standby charges in exchange for a service, should it take additional actions to ensure consistency with statewide greenhouse gas emissions and criteria air pollution reduction goals? For example,
    a) Should the CPUC impose a maximum emissions limit other than one of those listed in the question above?
    b) Should the CPUC define periodic reporting requirements to demonstrate a reduced carbon intensity compared to a standard?

   Please explain any other suggestions you think would address this goal.

F. Questions to Identify Details of Proposed Service Provided

1) What existing services (define and describe in detail) do distributed energy resources in microgrids already qualify for that the microgrid owner can offer to the IOU or the CAISO?

If microgrids aren't NEM resources or Qualified Facilities, it's very hard for them to sell energy (see discussion above at Question B. 2.). If a microgrid has a CAISO interconnection, it can sell demand response through an aggregator.[21]   FERC Order 2222[22] will expand wholesale markets, probably in 2022. The challenge is that microgrids are capable of providing services to *both* utilities and CAISO, but there is not an interconnection pathway structured for this. To our knowledge, in order to provide RA and other ancillary services to the wholesale market, a resource must interconnect under WDAT, which has a lengthy timeline for interconnection. Most microgrids provide distribution level services and in some cases are eligible for Rule 21 interconnection, but this currently precludes them from participating in CAISO markets. A challenge and an opportunity for the Commission would be to develop a microgrid tariff that allows DERs to both interconnect in six months or less and provide the full suite of grid services they are technically capable of providing today.

"The State of the Resource Adequacy Market".

[21] *See discussion in,* Post-Technical Conference Comments of the California Independent System Operator Corporation filed in FERC Docket RM18-9-000, *available at*, https://www.caiso.com/Documents/Jun26_2018_Post-TechnicalConferenceComments-Participation_DERA_MarketsOperated_RTOISO_RM18-9.pdf

[22] 172 FERC ¶ 61,247.

2) Under what specific circumstances would it be in the public interest to require utilities to waive or reduce standby charges to a microgrid for intentional islanding? How should the benefits to the public be identified, measured, and valued?

Intentional islanding is a form of demand response. The costs to operate in island mode are likely to be very different for different microgrids and may vary widely depending on the ambient conditions and the duration of islanding. This is an example of the difficulties of making vague tradeoffs rather than well specified services as described above.

3) Would providing electric service to a critical facility as defined by D.19-05-042 in situations where the IOU does not provide service, such as during a planned public safety power shutoff, be sufficient to merit waiving or reducing standby charges? (E.g., if a microgrid that serves a critical facility must island to continue to provide service to the critical facility during a utility planned outage such as a PSPS, should the standby charge be waived or reduced for that microgrid for any month in which that occurred?) If so, why should a waiver or reduction in standby charges be available to microgrids and not other types of backup generation? Please explain your answer. If you think criteria other than those defined in D.19-05-042 should be used to determine eligibility, please explain which criteria should be used and why.

This question does strongly suggest that microgrids (or other resources) that provide backup to utilities who abandon their obligation to serve and declare PSPS events to shield themselves from liability, should get the professional courtesy of an exemption from standby charges. It is not clear why that should be limited to the month in which a PSPS occurs. Microgrids are providing year-round backup. Will standby charges be limited to the rare occasions when generators fail?

4) Other than islanding, is there a different type of grid service that can be uniquely provided by microgrids (or specific types of microgrids), and not the individual resources comprising the microgrids, that would merit a standby charge waiver or reduction (please define the type of microgrid and the grid service)? How should the benefits to the public be identified, measured, and valued?
5) How should a customer be required to demonstrate that it can provide a particular service in exchange for a standby charge waiver or reduction and why?
    a) Physical equipment meeting certain specifications;
    b) Software settings capable of inducing equipment behavior;
    c) Contractual obligation only;

d) Combination of the above;
e) Other.

The answer to this question clearly depends on the service. In general, contractual obligations with financial consequences for failure to perform are preferred. Financial assurances may be appropriate, and a microgrid could elect between automated response and providing such assurances. Physical limitations are very unlikely to be efficient.

6) What trigger should CPUC require a customer to respond to in exchange for a waiver or reduction in standby charges and why? Examples:
   a) Warning of Stage 3 Emergency ;
   b) Specific temperature threshold (please specify);
   c) Price threshold (please specify);
   d) Emergency situation on the electric distribution or electric transmission system (please specify);
   e) Situation impacting system restoration (please specify);
   f) Emergency declaration by local, state, or federal authority;
   g) Designated situation specific to IOU bi-lateral agreement;
   h) Other

G. Cost Benefits Questions

1) Are standby charges appropriately rooted in cost causation principles? If reducing or exempting microgrids from standby charges would result in a cost shift prohibited by Senate Bill 1339, please detail how.

The MRC believes that standby charges have lost their moorings in cost causation. In the 2001Standby Decision PG&E successfully argued that there were very few DERs, and that the lack of diversity suggested that each DER should shoulder a large proportion of the costs of standby capacity to serve its needs.[23] This is clearly no longer accurate; diversity is far greater. Utilities could provide accurate information, and the Commission could require it, but as a rule the parties to this proceeding would not have access. The architecture of the distribution system will create local divergences, but the current standby charge does not pretend to take those into effect (and, as discussed above, where there is limited ability to serve a resource it is also probably true that the resource is providing large non-wires benefits on a regular basis).

In addition to the increasing diversity of DER on the grid, microgrids typically incorporate

[23] 2001 Standby Decision at 55.

diverse resources internally. These are likely to include solar generation, battery storage, fuel-based generation, building management systems and other internal load shedding capacity, and system controls, and may include, for example, other renewable resources, legally required backup generation, and thermal storage. They will not all fail together. Maximum hourly peak demand is clearly not an appropriate measure of standby requirements, and the capacity of the largest resources is also unlikely to reflect performance on the loss of generation. The largest capacity resource may not be intended as base load, a battery that is charging can switch to discharging, legally required backup power can come on, or the microgrid can shed load. This all argues for customer nomination of required backup, subject to utility review. Adjustments for performance over time make sense.

Other factors also enter in. The reservation charge is generally based on allocating the fixed cost of equipment in place.[24] Measuring that on non-coincident peak loads for each customer necessarily leads to a sum of usage amounts that exceeds both actual average usage and coincident peak usage. The Commission generally uses Equal Percent of Marginal Cost (EPMC) to set rates.[25] In other words, rates are set to cover the utility's revenue requirement in a way that is proportional to each rate class' contribution to marginal cost. The design size of the distribution system is based on coincident peak and is a relevant measure cost causation and historic fixed costs should to some extent be allocated on average usage. There is no real justification for non-coincident peaks. Moreover, having those charges recomputed by the month leads to unnecessary and inappropriate variability in allocation of fixed costs. Finally, to a large extent the utility determines the necessary local system expansion to serve a load at the time of interconnection and charges the customer for the needed capacity to serve it. If a new microgrid reduces imports by an existing customer, the local standby capacity is already there.

Comparison of the reservation component of standby charges with demand charges in other rate schedules strongly suggests that standby charges are inappropriately high. From November 2014 to November 2019, PG&E standby total reservation charges increased 133% from $3.33/kW to $7.75/kW. In contrast, over this same time period, summer and winter demand charges for A-10 TOU increased 44% from $13.40/kW to $19.25/kW and 82% from $6.68/kW to $12.17/kW, respectively. For E-19 over the same five-year time period, maximum monthly demand charges

[24] 2001 Standby Decision at 51.
[25] TOU Decision at 12.

increased 59% from $10.24/kW to $16.27/kW.[26] Moreover, a comparison of current charges also suggests inequity. The current PG&E Reservation Charge for distribution under Schedule SB is $8.07 per kW per month (applied to 85 percent of the Reservation Capacity).[27] The current PG&E demand charge for distribution under Schedule B-20 is $28.69 per KW per month summer (with different sub-rates applied to different non-coincident peaks) and $12.87 per KW per month winter (applied to peak period peak). To roughly equalize these charges, one has to assume that the usage of the distribution system on a standby basis under Schedule SB is over 25 percent in summer and over 60 percent in winter! It is hard to see any justification for this cost allocation.

Finally, we believe that generators below a certain size do not fail in sufficient concentrations in any given region of the grid to constitute anything more than noise in the overall operation of the grid. The suggestion for a 5 MW lower limit is somewhat arbitrary and intended to be rebuttable, but we doubt that it is easily rebutted. Above 5 MW it seems clear that current rates are highly arbitrary, and we simply suggest that they be suspended unless and until better cost analysis and allocation is provided.

2) How can the estimate of public benefits to non-participating ratepayers not connected to a microgrid be quantified in such a way as to be able to provide a basis for waiving or reducing standby charges?
3) What form of evidence that the microgrid provides incremental benefit to other customers must the microgrid owner provide to justify the waiver? (e.g. If the microgrid can demonstrate measurable, quantified benefits to non-participating customers or the utility or the microgrid serves critical facilities, essential services and others identified by D.19-05-042.)

This should not be done on an individual basis. It would be time consuming and arbitrary.

4) What controls are needed to ensure that the customer generator or microgrid project is not over-compensated and not double-counted from among multiple programs. including the Base Interruptible Program, the Emergency Load Reduction Program, individual power purchase agreements or bilateral contracts, Net Energy Metering, and the various incentive programs such as the Self Generation Incentive Program?

I. Questions to Identify Details of Potential Waiver

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[26] R.19-09-009 Track 2 Staff Concept Paper pg. 64 and PG&E Tariff Books for A-10 and E-19 https://www.pge.com/tariffs/electric.shtml

[27] *See*, https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_SB.pdf
For a 5 MW generator this amounts to $411,570 annually in perpetuity. This amount would amortize over $5 million at 5 percent over 15 years. In other words, the charge is equivalent to adding over $5 million to project cost. At the rate the charge has been escalating the actual lifetime cost is much higher.

1) What specific parts of the standby charges rate schedule should be waived or reduced, if any waivers or reductions are granted?
   a) Reservation;
   b) Other (please explain).

We suggest elimination of all standby charges for microgrids under 5 MW, and elimination of the distribution portion of the reservation charge for microgrids 5 MW and greater.

2) What amount of standby charges should be waived if waivers are granted, and why?
   a) All;
   b) Proportionate to benefit;
   c) All if no demand charges in that billing period;
   d) Other (please explain).
3) How long should a waiver be granted if any waivers are granted, and why?
   a) Indefinitely;
   b) Certain number of years (please specify);
   c) Annual, with annual renewal;
   d) Certain capacity enrolled;
   e) Other (please explain).
4) If the CPUC takes the action above such as modifying the standby charge, should CPUC limit the applicability of the standby charge waiver to new projects, or should the waiver apply to existing projects as well? Please justify your answer, after first stating your position:

If, as we believe, current standby charges represent an improper cost shift to microgrids, they should be reduced or eliminated for all microgrids.

   a) Please describe what types of incremental benefits a waiver of standby charges would be likely to enable existing microgrids to provide to non-microgrid customers. Please describe in detail how a waiver of standby charges would enable the delivery of each proposed benefit, and how the benefit would be incremental to the present circumstances.

We described those benefits in response to Question B. 2.

   b) Please estimate, in $/MW, the financial value of each incremental benefit that waiving standby charges for existing microgrids would deliver to non-microgrid customers.

It is not realistic to ask this of participants in the proceeding. The NEM 2 cost effectiveness study took months of work by professional econometric analysts. We have had three weeks' notice.

Conclusion

The MRC respectfully requests that the Commission (i) exempt small microgrids from standby charges entirely, (ii) take interim action to exempt all microgrids from the distribution component of the reservation charge of the standby tariff, and (iii) initiate a thorough study of the benefits and costs to the grid of microgrids prior to and as a necessary basis for reinstatement of any reservation charge and to support its further deliberations in this proceeding.

Dated: March 3, 2021

Respectfully submitted,

C. BAIRD BROWN

By: /s/ C. Baird Brown

C. Baird Brown

Attorney for
Microgrid Resources Coalition

Exhibit A

Information on DLC and SBC Burdens

The following information was supplied by Carol Denning, President of Energy Pathways, who has a long history of developing microgrids. In particular she was involved in a proposed 4 MW co-generation microgrid to support a group of biotech facilities on a University of California campus. The campus is already served by significant onsite and offsite solar, but the proposed project was a gas co-generation microgrid to provide hot water and assure ongoing electric service for some of the top bioscience research projects in the U.S. It was also expected to significantly reduce energy costs.

By way of background, the UC California system is operating 136 MW of cogeneration across their portfolio because of all of its attributes. These systems provide resilient, efficient energy to both UC hospital campuses, as well as UC educational campuses. She comments on that choice:

- *Resiliency*: In the past we were reluctant use fuel cells in any resiliency application because they easily trip off under poor power quality conditions from the grid (the new norm) or the intermittency of renewables coming on and off the microgrid. Once tripped off fuel cells can take several hours to come back online.
- *Efficiency*: As for efficiency, when there is a thermal source, CHP can reach efficiencies of up to 90%, whereas electric only technologies, at best 45-60% and still don't address the thermal loads.
- *Economics*: When affordability is a factor, long duration synchronous generation is a fraction of the cost of fuel cell technology. In many cases 30-50% less expensive depending on technology and application. This is an important point for our DAC's.

For this project, the design-build cost of the proposed plant is anticipated to be approximately $16 million with energy savings calculated at approximately $4.7MM under conservative economic conditions over the 20-year life of the project. The project shows savings if approved built and commissioned by December 31, 2020 before the departing load exemption for the Universities of California is due to expire. If the CHP plant is not completed by this deadline, the departing load charge will add a staggering $13 million in additional fees nearly doubling the cost of the project. The project financial analysis includes increased gas transportation charges for greenhouse gases and pipeline safety fees, 40% biogas beginning in 2025, carbon offsets for all GHG emissions (which increased slightly) property taxes and standby charges escalating yearly at 7% per year.

- The units would provide 27,557,563 kWh annually plus thermal district energy.
- Though one CHP unit was the better fit, two CHP units were configured because they decreased SBC's by $36,000 per month. The equipment tied to the CHP were boilers, chillers and backup generators.
- The actual annual DLCs were $455,000 and SBCs were $519,000 for an annual total of $974,000.
- The annual energy savings with neither DLCs nor SBCs was approximately $1.5 million.

The project has been delayed by utility interconnection processes and as a result will not meet the deadline to avoid DLCs.

Exhibit B

Examples of Microgrid Resilience

When Hurricane Sandy caused significant damage to the power grid and local infrastructure, with power outages of a week or more, Princeton University's microgrid (described in Appendix A) continued to function and provide electricity to the campus. This allowed Princeton to provide hot meals, hot showers and cell phone charging to first responders. In addition to the Princeton microgrid, other distributed energy resources in the region, such as the NYU downtown campus cogeneration facility and interconnected buildings and the NRG Princeton Medical Center microgrid, were able to remain online throughout Sandy. In contrast, the power failure and eventual closing of the NYU Langone Medical Center in midtown Manhattan drew national attention and initiated a review of the center's energy infrastructure. Below we provide a number of further illustrations of how microgrids can support the resilience of the grid.

Co-op City is a residential development home to roughly 50,000 people in the east corner of the Bronx. After the 2003 blackout, Co-op City invested in a microgrid served by a 40 MW CHP facility. During Superstorm Sandy, Co-op City was able to reliably provide electricity, heat, and hot water to its 50,000 residents without interruption.[28] In the aftermath of Sandy, Co-op City helped restore the grid by providing black start services to Consolidated Edison.[29]

Nassau Energy has a microgrid supported by a 57 MW CHP facility. During Superstorm Sandy, Nassau Energy provided power to the Long Island Power Authority, helping with restoration efforts. Furthermore, Nassau Energy provided thermal energy to the Nassau

University Medical Center and the Nassau Community College during Superstorm Sandy. In part because of Nassau Energy's services, the Medical Center was able to attend to several patients displaced from nursing homes during the storm, and the Community College served as an emergency shelter that provided services to over 1,000 people displaced by the storm for over one month.[30]

The College of New Jersey has a microgrid supported by a 5.2 MW CHP facility. The College operated in island mode during Superstorm Sandy and maintained electric service despite grid disruptions. In the aftermath of the storm, the College was able to use its equipment to back-

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[28] Environmental Defense Fund Report: Sandy Success Stories at 67-68 (Jun. 2013) (EDF Report) *available at* https://www.edf.org/sites/default/files/sites/default/files/content/SandySuccessStories_June2013.pdf.

[29] IDEA briefing jointly with the Microgrid Resources Coalition and the Environmental and Energy Study Institute on microgrid policy guidance (Dec. 6, 2016) (IDEA Briefing) *available at* http://www.eesi.org/briefings/view/120616idea.

[30] ICF International Report, Combined Heat and Power: Enabling Resilient Energy Infrastructure for Critical Facilities at 25 (Mar. 2013) (hereinafter "ICF Report") *available at* https://www1.eere.energy.gov/manufacturing/distributedenergy/pdfs/chp_critical_facilities.pdf.

feed one of PSE&G's power lines to bring it back to service.[31]

The Danbury Hospital (Danbury, CT) has a microgrid supported by a 4.5 MW CHP unit that provides the buildings at this 371-bed hospital with electric power and heat. The Danbury Hospital was able to withstand Superstorm Sandy due to its ability to operate in isolation from the microgrid during the storm and continued to admit patients from other sites that were forced to close due to the storm.[32]

The South Oaks Hospital (Amityville, NY) has a microgrid supported by a 1.25 MW CHP facility. During Superstorm Sandy, the Hospital isolated itself from the grid and was able to provide critical services for two weeks relying solely on its CHP system. The hospital admitted patients from other sites that had been displaced by the storm and offered refrigeration of vital medicines to those who had lost power and had no other means of keeping their medicines refrigerated.[33]

New York University (New York, NY) has a microgrid supported by a 14.4 MW CHP facility. During Superstorm Sandy, the NYU microgrid provided uninterrupted electric service, heating, and cooling to the campus, which served as a command post for New York City officials during the storm and served area residents that had been forced to evacuate their homes.[34]

The Louisiana State University ("LSU") (Baton Rouge, LA) has a microgrid supported by two CHP facilities totaling approximately 24 MW of nameplate capacity. LSU stayed online and never lost power during Hurricane Katrina in 2005, and again during Hurricane Gustav in 2008, allowing the campus to be used as shelter for many employees that had been displaced by the hurricanes.[35]

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[31] *Id.* at 18.
[32] *See* Dhanya Skariachan, *Hospitals battled to protect patients as Sandy raged*, Reuters, Oct. 30, 2012, http://www.reuters.com/article/us-storm-sandy-hospitals/hospitals-battled-to-protect-patients-as-sandy-raged-idUSBRE89T1NV20121030.
[33] ICF Report at 13.
[34] *Id.* at 29.
[35] *Id.* at 24.