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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements.	Rulemaking 13-09-011 (Filed September 19, 2013)

ADMINISTRATIVE LAW JUDGE'S RULING INVITING COMMENTS ON STAFF PROPOSAL REGARDING THE USE OF FOSSIL-FUELED BACK-UP GENERATION IN DEMAND RESPONSE PROGRAMS

Summary

This Ruling introduces a proposal from the Commission's Energy Division recommending that the Commission prohibit the use of fossil-fueled back-up generation in demand response programs beginning with the 2017 program year (Staff Proposal). In order to create a record to make a determination on whether to adopt a portion of or the entire Staff Proposal, parties in this proceeding are invited to review the attached proposal and respond in general and to the specific questions provided below. Comments are due no later than October 12, 2015; replies are due no later than October 15, 2015.

Background

Decision (D.) 14-12-024 confirmed the adoption of a policy statement that "the use of back-up generation[1] in demand response programs is antithetical to the Energy Action Plan and the Loading Order."[2] However, that same decision also determined that the record was incomplete to make a determination of whether it is prudent to prohibit the use of back-up generation in demand response programs. The Commission found that it should ascertain the depth of the issue by determining the number of back-up generators currently used in demand response programs and the extent they are being used. Hence, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (jointly referred to herein as the Utilities) were directed to collect information regarding the use of back-up generation and file the data in this proceeding (Rulemaking 13-09-011). The results of the data, due on November 30, 2015, would be used to determine next steps.

In February 2015, the Utilities each filed a back-up generation data collection plan via advice letters pursuant to D.14-12-024, OP 15. These advice letters have been protested and are currently in suspension.[3]

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[1] The terms fossil-fueled back-up generation and back-up generation are used interchangeably throughout this Ruling. For purposes of this Ruling, both refer to fossil-fueled back-up generation and include the following resources: distributed generation technologies using diesel, natural gas, gasoline, propane, or liquefied petroleum gas, in combined heat and power (CHP) or non-CHP configuration.

[2] D.14-12-024 at Ordering Paragraph (OP) 10.

[3] The Office of Ratepayer Advocates (ORA), the Joint Demand Response Parties, BloomEnergy, the California Large Energy Consumers Association (CLECA), and the Sierra Club all filed timely protests to the advice letters.

On July 23, 2015, the Commission adopted Resolution E-4728, which approved—with modifications—proposals of the Utilities to create an auction mechanism for demand response capacity, referred to as the demand response auction mechanism. Resolution E-4728 also required the Utilities to exclude fossil-fueled back-up generators from participating in the auction mechanism bidding.

A Joint Assigned Commissioner and Administrative Law Judge Ruling was issued on August 6, 2015 asking parties to comment on proposed guidelines to the Utilities for filing proposal to improve demand response programs during the 2017 bridge funding year. In that Ruling, the Commissioner and Administrative Law Judge referenced Resolution E-4728 and the adopted policy of prohibiting fossil-fueled back-up generation in the demand response auction mechanism pilot. The Ruling asked parties to comment on whether the Commission should adopt a fossil-fueled back-up generation prohibition policy for the overall demand response program beginning with the 2017 program year.

A final 2017 demand response program guidance Ruling was issued on September 15, 2015. In that Ruling, it was determined that a bridge funding Ruling is not the appropriate venue for addressing the issue of fossil-fueled backup generation; this issue was tabled. However, at that time, the parties were notified of the concerns regarding the data collection issues, which arose in the processing of the Advice Letter filed pursuant to D.14-12-024. The Ruling stated that the Commission would address the fossil-fueled back-up generation data collection issue in a future Ruling.

Overview of Staff Proposal

The Commission's Energy Division has proposed that the Commission should adopt a policy prohibiting the use of fossil-fueled back-up generation in

demand response programs now instead of pursuing data collection (Staff Proposal). The Staff Proposal (attached as Appendix A) defines fossil-fueled back-up generation as the following distributed energy resources: distributed generation technologies using diesel, natural gas, gasoline, propane, or liquefied petroleum gas, in CHP or non-CHP configuration.[4] This is the same definition as that used in E-4728 and is consistent with the Loading Order, which prioritizes energy efficiency and demand response at the top of the list for resource investments, followed by renewable resources and distributed generation, and, at the bottom of the list, conventional electricity supply.

The Staff Proposal recommends that the Commission adopt this same definition and prohibit the use of these resources in demand response activities. Additionally, the Staff Proposal recommends enforcement of this prohibition through attestation for residential customers and the use of proration for nonresidential customers. The Staff Proposal also recommends that nonresidential customers have two options for proration: select metering or derating their payments to reflect the size of their back-up generator.

Discussion

In order to determine whether to adopt the Staff Proposal, either in part or in its entirety, the Commission requires the creation of a record on the Staff Proposal. Hence parties are invited and encouraged to file comments on the attached Staff Proposal no later than October 12, 2015. Reply comments are due no later than October 15, 2015.

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[4] Stand-alone storage and storage coupled with renewable generation is permitted, but must meet the relevant greenhouse gas emissions factor thresholds adopted by the Self-Generation Incentive Program.

In addition, parties are asked to respond simultaneously to the following ten sets of questions:

1. The Staff Proposal recommends that the Commission proceed directly to adopting a policy prohibiting fossil-fueled back-up generation usage in demand response, rather than resolve problems with the back-up generation data gathering plan submitted by the Utilities. Do you agree with this change in direction? If you disagree, please explain how the Utilities' proposed back-up generation data collection plan will provide the Commission the data it needs to determine a back-up generation policy in light of the data collection issues raised by staff (*see Staff Proposal at 2-3*). Please explain how the Utilities' proposed data collection plan will result in the Commission's ability to establish a policy regarding the use of back-up generation prior to the approval of the 2018 demand response portfolio.

2. The Staff Proposal recommends that the following fossil-fueled distributed energy resources be prohibited or disqualified for use in demand response activities: distributed generation technologies using diesel, natural gas, gasoline, propane, or liquefied petroleum gas, in CHP or non-CHP configuration (*see Staff Proposal at 6-7*). Should any of the listed distributed energy resources be eliminated? Should any distributed energy resources be added to the list? Should the list be clarified in any way?

3. The Staff Proposal recommends that stand-alone storage and storage coupled with renewable generation is allowed to be used in demand response, but must meet the relevant greenhouse gas emissions factor thresholds adopted for the Self Generation Incentive Program (*see Staff Proposal at 7*). Should this exemption be adopted as is? Should a modified version be adopted? If so, what modifications should the Commission consider?

4. The Staff Proposal recommends a hybrid enforcement mechanism, differentiating between residential and nonresidential customer sites and providing a range of certainty which is lower for residential customer sites and higher for

nonresidential customer sites (*see Staff Proposal at 8-10*). It also provides an option for nonresidential customers to choose whether enforcement occurs through a default adjustment based on the rated capacity of the onsite distributed energy resource or a metered adjustment. Should this proposal be adopted as is? Should a modified version be considered? If so, what modifications should be considered?

5. The Staff Proposal recommends that demand response participants be responsible for the cost of the meter and its installation (*see Staff Proposal at 10*). Should the Commission consider other options to fund the cost of the meters and their installation? Please provide those options and the policy rationale for them.

6. What are the estimated costs for an interval meter and its installation?

7. If a demand response customer claims that it has no back-up generation on its premises, the Staff Proposal requires the utility or demand response provider to verify the claim bi-annually with site visits or cross-examining other data sets (*see Staff Proposal at 9*). Are there other ways to perform the verification? Is a bi-annual verification requirement frequent enough or should the verification be performed more often?

8. The Staff Proposal provides an example of how incentive structures for demand response programs would be adjusted or prorated to account for back-up generation usage in demand response (*see Staff Proposal at 10*). Are there other ways to adjust the incentive structures for demand response programs if a proration policy is adopted? Are there demand response programs that require their own unique application of a proration policy?

9. The Staff Proposal recommends specific roles for the Utilities and third-party providers for the implementation of the proration policy with regard to Aggregator Managed Portfolio contracts (*see Staff Proposal at 9*). Should the proposed roles be modified in any way?

10. Should the Commission implement the policies concerning back-up generation use for demand response all at once or gradually? For example, should attestation be allowed for some period of time after which more certain enforcement mechanisms are required? If gradual implementation is recommended, what requirements are recommended at what intervals?

Parties are encouraged to contact staff for clarifications on the Staff Proposal or the questions above. However, the contact shall be made through email and simultaneously sent to the entire service list for this proceeding. Staff shall respond via email to the entire service list. The contact person for the Staff proposal is Bruce Kaneshiro at bruce.kaneshiro@cpuc.ca.gov. By using this contact process, all parties will receive any additional information from Commission Staff simultaneously.

IT IS RULED that:

1. Parties shall file comments on the attached Commission staff proposal prohibiting the use of fossil-fueled back-up generation in demand response programs beginning in 2017 and responses to the ten sets of questions provided within this Ruling, no later than October 12, 2015. Reply comments shall be filed no later than October 15, 2015.

2. Clarifications and questions regarding the attached Commission staff proposal shall be e-mailed to bruce.kaneshiro@cpuc.ca.gov. and copies to the entire service list of Rulemaking (R.) 13-09-011. Responses to the clarifications and questions shall also be e-mailed to the service list of R.13-09-011.

Dated September 29, 2015, at San Francisco, California.

/s/ KELLY A. HYMES

Kelly A. Hymes
Administrative Law Judge

APPENDIX A

Demand Response and Back Up Generation

Energy Division Staff Proposal

September 21, 2015

- **Background:**

For over a decade the Commission has repeatedly defined demand response as not including the use of fossil-fueled backup generation (BUGs).[1] The Commission recently stated that the use of fossil fueled (BUG)s in demand response (DR) is antithetical to the Energy Action Plan and the Loading Order.[2] Public Utilities Code Section 380.5 (a)(1) provides that "In establishing a demand response program, the commission shall….establish rules consistent with state and federal law for how and when back-up generation may be used within the [DR] program and establish reporting and data collection requirements to verify compliance with those rules." In passing this code section (SB 1414, Wolk, 2014), the Legislature found that "increasing the role of DR will reduce emissions of GHG and other pollutants from the electricity sector." Further the Legislature stated its intent "to ensure that California and the [CPUC] help meet the state's GHG reduction goals… by increasing the utilization of DR."[3]

In December 2014, the Commission declined to establish specific rules that prohibit the use of BUGs in DR because it reasoned that it had insufficient evidence on the size of the problem.[4] Pursuant to Decision D.14-12-024 (the Decision) the Investor Owned Utilities (IOU)s were ordered to gather specific BUG data from DR participants so that the Commission can determine the size of the problem, and then decide if prohibition was necessary.

In February 2015 the IOUs filed a BUG data collection plan via advice letters[5] in compliance with the Decision. Energy Division's assessment is that the IOUs' proposed data collection plan contains several flaws and misinterpretations of the Decision such that we are skeptical that the IOUs' proposed data collection plan will result in valid or useful data for future policy development. The main flaws in the IOUs' proposed data collection plan are:

1. Existing BUG meter data is likely to be in the form of cumulative run hours.[6] Cumulative run hours indicate the total time a BUG unit was operated but does not necessarily demonstrate if the BUG unit was operated coincident with a DR event. Hourly interval meter data is necessary to determine if a BUG unit was used by a participant to provide demand response load drop. Local air districts enforce additional hand-written hourly logs for BUG units; but it is unknown as to how accurate or dependable such logs are, and the extent to which they are required and monitored in air districts where DR participation is prevalent.

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[1] D.03-06-032 Attachment A p. 2, D.06-11-049 p. 58, D.09-08-027 pp 164-166 and D.11-03-003 p. 26.
[2] D.14-12-024, Finding of Fact 68.
[3] See SB 1414 (Wolk, 2014) legislative finding and intent: http://www.leginfo.ca.gov/pub/13-14/bill/sen/sb_1401-1450/sb_1414_bill_20140926_chaptered.pdf.
[4] D.14-12-024, Findings of Fact 69 and 72.
[5] PG&E AL 4582-E, SCE ALs 3173-E and 3174-E, SDG&E ALs 2699-E and 2700-E.
[6] The California Air Resources Board's (CARB) Airborne Toxic Controls Measure (ATCM) 93115 requires installation of a 'non-resettable' hour meter with a minimum display capability of 9,999 hours on diesel-fueled BUG 50 hp or larger. Energy Division interprets the ATCM to mean that the meter records cumulative usage, akin to a car odometer. Southern California Edison's Comments on the Proposed and Alternate Decisions in R.13-09-011 (which became D.14-12-024) reflect a similar conclusion about the ATCM: "It is SCE's understanding that BUG usage is often recorded with a simple total run hour meter, which does not record the time the generator was used, only the amount of time it was used. In order for SCE to collect the required information, it may be necessary to install sub-meters on each of the self-certified BUGs."(p. 5, November 17, 2014).

2. There may not be any operating data for some BUGs. California Air Resources Board and local air district regulations are mainly focused on BUGs that are 50 hp or larger. Thus, there may be no current way to verify the extent to which smaller BUG units are being used in conjunction with DR.[7]

3. The provision of BUG data from DR participants is *voluntary* per the IOUs' proposed BUG data collection plan. Even if relevant BUG meter data was available, if a DR participant refuses to provide that information, there are no repercussions for that customer per the IOUs' proposed data collection plan. The IOUs state that the Decision did not specifically authorize any negative repercussions (such as removal from DR programs) for DR participants who refuse to provide their BUG data.

4. Undefined cost: the IOUs do not provide any cost estimates for their proposed BUG data collection effort, but have implied it will be in the $ millions, as they will rely on a consultant and use of expensive surveys to get the data.

The data collection plan could potentially be improved, but it will likely require a modification of the Decision. A revised data collection plan may take a year or more to implement. An additional 6-12 months may reasonably be expected for the Commission to assess the data and adopt a policy on BUGs in DR. In short, a final policy on BUGs and DR is unlikely to be adopted until 2018, too late to include in the IOUs 2017 transition year program filings as well as DR programs starting in 2018[8]. The recent Demand Response Auction Mechanism (DRAM) Resolution (E-4728) and parties' comments on the 2017 Guidance Ruling (R.13-09-011) indicate that stakeholders are demanding a definitive policy on BUGs and DR. But the current trajectory suggests that such a policy will not be finalized until 2018 at the earliest.

- **The Commission Should Set a BUG-DR Policy Now, Instead of Pursuing BUG Data Collection:**

In D.14-12-024, the Commission declined to prohibit or otherwise adopt rules for BUG participation in DR because it did not have enough evidence on the size of the problem[9]. While a full evidentiary showing has yet to be rendered, there are data points to suggest that the scale of the problem may be significant. In a 2010 California Statewide Process Evaluation of DR Programs 60 percent of demand response participants who owned a BUG admitted to using it during demand response events[10].

Given the aforementioned concerns with the IOUs' proposed data collection plans and length of time it will take to adopt a final DR BUGs policy, Energy Division recommends that the Commission proceed

[7] SDG&E's comments on the Proposed and Alternate Decisions in R.13-09-011 (which became D.14-12-024): "There is no data suggesting that customers with small generators, those not covered by air quality regulations, keep records of hourly usage of the generation." p.5, November 17, 2014.
[8] Commission approval of 2018 DR programs would necessarily need to occur in 2017.
[9] Ordering Paragraph 69.
[10] KEMA, "Final Report: California Statewide Process Evaluation of Selected Demand Response Programs," April 7, 2010, at p. 2-95. Available at CalMAC.org database, Study ID CPU 0025.01

directly to set a policy prohibiting BUG usage in DR on the basis that using fossil fuel BUGs in DR is inconsistent with California's climate and environmental policy goals. The fact that a DR-BUGs policy is unlikely to be adopted until after the 2018 DR portfolio is already in place (assuming the current data collection plan is followed) is an outcome that should be avoided

Furthermore, the issue has been raised several times in other proceedings. As mentioned earlier, stakeholders have advocated for a more definitive policy on BUGs and DR in the Commission's resolution on the DRAM and the 2017 Transition Year guidance. In addition to these proceedings, BUGS and DR has been raised by stakeholders in SCE's Locational Capacity Resource (LCR) RFO proceeding (A.14-11-012) and the SGIP policy review proceeding[11]. These aforementioned proceedings suggest that the Commission needs to start addressing a DR and BUGs policy expeditiously as it has implications for Resource Adequacy, future DR procurement mechanisms, and participation of DR in CAISO wholesale markets. Addressing these implications will take time; and they are unlikely to be completely resolved in a single process. Hence, Energy Division staff's proposal provides a starting point for DR-BUGs policy that can be built upon when and where appropriate.

Lastly, the Commission is now required by law to "establish rules consistent with state and federal law for how and when back-up generation may be used within the (DR) program and establish reporting and data collection requirements to verify compliance with those rules." And the Commission shall "establish metering and monitoring policies" for DR programs.[12]

Below we discuss the relevant policy issues supporting a recommendation to move forward with a DR-BUGs policy.

- **Policy issues with Customer Side Resources being used in DR:**

A. Environmental issues. These have three dimensions:

i. **EAP Loading Order.** PU Code Section 454.5 places energy efficiency and "demand reduction" (DR) first in the loading order. The EAP II identifies renewables and clean DG (such as CHP) as second in the loading order. So, CHP is clearly a second-order preferred resource. As a demand side resource, <u>DR is the reduction of energy consumption or shifting consumption to another time period</u>.[13] Relying on a customer side generating resource to reduce load to the grid is akin to masquerading as DR.

ii. **GHG Emissions.** DR is a preferred resource and an integral part of the state's overall GHG strategy. Certain customer generation resources have higher GHG emissions than others, and thus, this needs to be considered. By statute, eligible SGIP technologies must avoid GHG emissions. Currently fossil-fueled CHP and fuel cell technologies are considered to have lower GHG emissions than the grid average, but these emissions factors are under

[11] In the SGIP policy review (R.12-11-005), the dual participation of SGIP resources in DR programs and the issue of "double-dipping" are being examined. BUGs and DR could affect the Integrated Demand Side Resources (ISDR) proceeding as well as the Distribution Resource Plan (DRP) proceeding.
[12] PU Code § 380.5
[13] D.12-04-045, page 2

review in a pending SGIP Proposed Decision, which could eliminate some of these technologies from the program.

iii. **Public Health.** Fossil-fueled customer generation may have public health implications due to local criteria pollutant emissions.[14] In the best case, with proper air permits, (non-fuel cell) fossil-fueled customer generation still produces more harmful emissions than central station generators. In the worst case, these units may operate illegally without permits or exceed allowable hours of use under their permits.[15]

B. **Double Payment.** Certain customer generation resources (both renewable & fossil fuel) already receive Commission-authorized incentives (such as through SGIP). Allowing DR incentives for such resources could result in ratepayers paying twice for the same action or benefit.[16]

In response to the SGIP ACR, 8 of 12 commenters want to address double-dipping; 5 commenters want to allow SGIP / DR dual enrollment with no restrictions. All three IOUs acknowledge double dipping and want to address it either by outright prohibition of dual enrollment (SDG&E) or by allowing dual enrollment but having policies preventing double-dipping (SCE & PG&E).

The extent to which the double payment issue is a concern depends on:

i. Whether one believes the SGIP incentives are primarily meant to overcome the capital cost of installing these technologies, but that additional incentives may be necessary (and justifiable) to encourage the operation of these systems on peak when the grid needs them most. Conversely, one might say that because **peak demand reduction** is one of SGIP's **statutory goals**, installations should be expected to operate on peak without additional incentives. (Current SGIP rules do not require on-peak operations; residential AES is an exception.)

ii. Relative weight given to the market transformation goals of the SGIP program versus peak savings (and GHG reductions). Placing additional requirements on the SGIP program or limiting opportunities to participate as DR could dampen market transformation effects.

- **Defining a "BUG": what resources should be prohibited with DR?**

The DR rulemaking (R.13-09-011) focused on fossil-fueled backup generation, however it did not clarify or define what resources are considered a BUG. BUGs are a subset of customer-side distributed energy resources (DERs) that raise policy concerns when used in conjunction with DR. As illustrated in Figure 1,

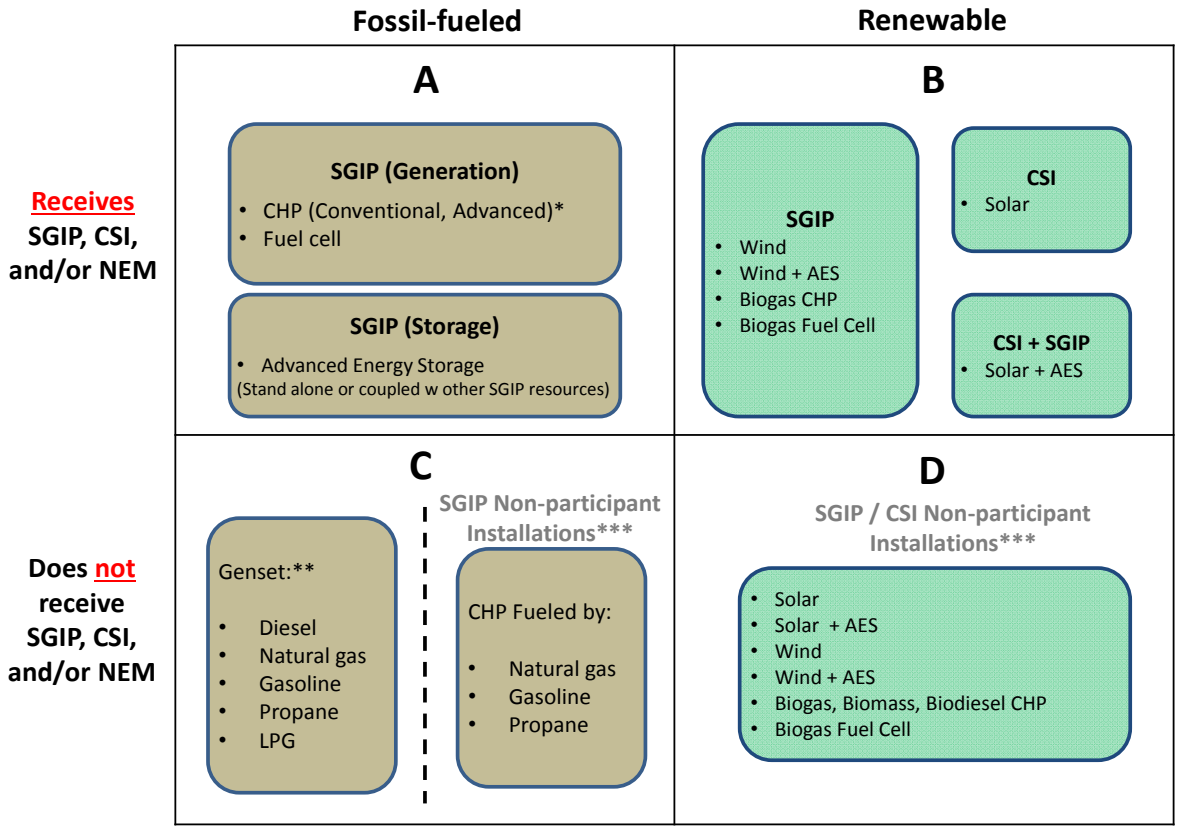
[14] Also all fossil-fuel resources carry public health implications (emission rates, intake fraction, NOx, Sox, PM, etc.) These impacts are often several times higher compared to central power plants. A 2006 study in CA showed that the intake fraction for nonreactive primary air pollutants was 20 times higher for small-scale, urban-sited distributed electricity generation (DG) sources than for large-scale, central power plants in California [Heath, G.A., Granvold, P.W., Hoats, A.S., Nazaroff, W.W., 2006.]

[15] South Coast AQMDs comments on the IOU DRAM ALs indicate that fossil "back up generators" may operate under air permits for emergency back-up applications limited to ~200 hours annually. They say that a fossil DG unit could operate under a "prime" permit (subject to Best Available Control Technology), but no such permits have been issued in California.

[16] SGIP Policy has some measures to prevent double dipping with DR however they are only applicable to one specific array of DR programs. This is being addressed in the SGIP program review proceeding.

BUGs are part of a broader "ecosystem" of customer-side DERs, characterized by their fuel type (renewable or fossil-fueled), and whether or not they receive policy support (through SGIP, CSI, NEM).

Figure 1 illustrates the customer-side DER "ecosystem" as it pertains to the BUG-DR nexus, according to fuel type (Renewable or Fossil Fuel) and whether they receive other (non-DR) incentives.



* Conventional CHP (ICE,MT,GT, ST) , Advanced CHP (WTP, PRT)
{ Internal **C**ombustion **E**ngine, **M**icro-**T**urbine, **G**as **T**urbine, **S**team **T**urbine, **W**aste **H**eat to **P**ower, **P**ressure **R**eduction **T**urbine}
**Not eligible for SGIP
***These are SGIP or CSI non-participant installations, which are likely very few.

Figure 1

The Decision clearly intends for BUG policy to address traditional fossil fueled DG technology (gensets) in quadrant C, but the language is vague and could be interpreted more broadly to include fossil-fueled "clean DG" and storage technologies in quadrant A. Meanwhile, the SGIP policy review under way in R.12-11-005 is re-examining whether dual participation of SGIP resources in DR programs should be permitted. Hence, which resources should be defined as "BUG" for purposes of prohibiting or limiting their use with DR is critical and has implications for resources outside of the DR proceeding.

➢ **Policy Recommendations:**

Staff recommends the following fossil-fueled DERs be prohibited or disqualified for use in DR: distributed generation technologies using diesel, natural gas, gasoline, propane, or liquefied petroleum

gas, in CHP or non-CHP configuration[17]. Stand-alone storage and storage coupled with renewable generation is allowed[18], but must meet the relevant GHG emissions factor thresholds adopted for the SGIP program.

This policy should apply to all DR participants receiving capacity, energy, or other incentive payments from the IOU, directly or indirectly.[19]

- **Enforcement Options Considered:**

The following enforcement options were evaluated in terms of their cost (if available), impact on DR, simplicity/ease of implementation, and enforceability.

A. Outright ban: This means that if a customer has a BUG on their premises, that customer cannot participate in a DR program/contract.

This approach is simple and has low cost of implementation, but it is a blunt instrument which could leave out a lot of non-BUG induced DR potential that the participant could provide. It also requires some enforcement mechanisms to ensure that DR participants do not own BUGs.

B. Attestation: This option allows a customer to own a BUG on their property, but enables the customer to participate in a DR program/contract by declaring or attesting to not use the BUG during DR events. It also provides some repercussions to the DR participant, because if they are found to be in violation of their attestation they could be removed from the program.

This approach is also simple and economical to implement and it is superior to Option A in that it captures non-BUG induced DR potential from BUG owners. However, this option would be difficult to enforce: without metering or some other method of verification, the IOU would have no reliable and consistent way to determine if the customer was fulfilling its vow not to use the BUG for DR.

C. Proration: Similar to Option B, this options allows the customers with the BUG to participate in DR, but not get compensated for load drop attributed to the BUG. This approach can be accomplished in two different ways:

a. ***Metering:*** An interval meter on the BUG unit enables the IOU to determine the extent to which a BUG unit was used for DR and thus make the appropriate proration to the incentive payment so that only non-BUG assisted DR is compensated. This option is

[17] This definition is consistent with the loading order which prioritizes investments first in energy efficiency and demand response, followed by renewable resources and distributed generation, and only then clean conventional electricity supply. This is also the definition adopted in the DRAM Resolution E-4728

[18] Storage is allowed (and indeed encouraged) because of its important role for renewables integration and in meeting AB 2514 storage procurement targets per DRAM Resolution E-4728.

[19] Some IOU programs, such as the Aggregated Managed Portfolio (AMP), are structured so that participants receive incentive payments from a third-party demand response provider, who is under contract with the IOU to provide DR capacity. Such arrangements are indirect payments from the IOU and are therefore included in the policy.

superior to Option A in terms of maximizing non-BUG DR potential, and superior to Option B in terms of enforceability. Under this option, the DR participant would be responsible for the cost of the meter and its installation. The cost of necessary metering may not be worth it for smaller customers / sites with less DR potential. Metering costs are lowered to the extent that the BUG unit already has an interval meter that can be leveraged. There will also be the cost to implement new proration processes and procedures within the IOU.

b. ***BUG rated-capacity proration:*** Instead of using a meter to determine the proration, this sub-option automatically prorates the DR incentive based on the rated capacity of the BUG unit. This sub-option is superior to Options A and B in the same manner as Sub-Option C.a. However it is not as accurate as Sub-Option C.a since it presumes the customer will be using the BUG unit on every DR occasion when that might be occurring only part of the time. On the other hand, this sub-option would be less expensive to the customer than sub-option C.a, since there are no metering costs.

D. **Hybrid proration / attestation:** This option allows small customer sites (residential and maybe small commercial) to attest the non-use of BUGs but uses proration for larger customers (customer has the option to select metering or the BUG rated capacity method). Similar to how the SGIP requires Performance Based Incentives (PBI) (with metering to support it) for systems over 30 KW, an initial BUG policy could focus on the largest customers which are most likely to have BUGs installed.

This approach would require less meter installations, while ensuring that non-BUG induced DR potential on larger customer facilities is fully tapped.

As noted earlier, Resolution E-4728 prohibited the use of fossil-fueled BUGs in demand response contracts procured through the Demand Response Auction Mechanism (DRAM). Bidders in the DRAM were provided options to ensure that fossil-fueled BUGs were not being used to provide DR, such as through attesting that their bid proposals do not rely on BUGs or through metering arrangements on their participants. Hence Resolution E-4728 adopted a combination of Options B and C above, which is effectively Option D.

- **Recommended Enforcement Mechanisms:**

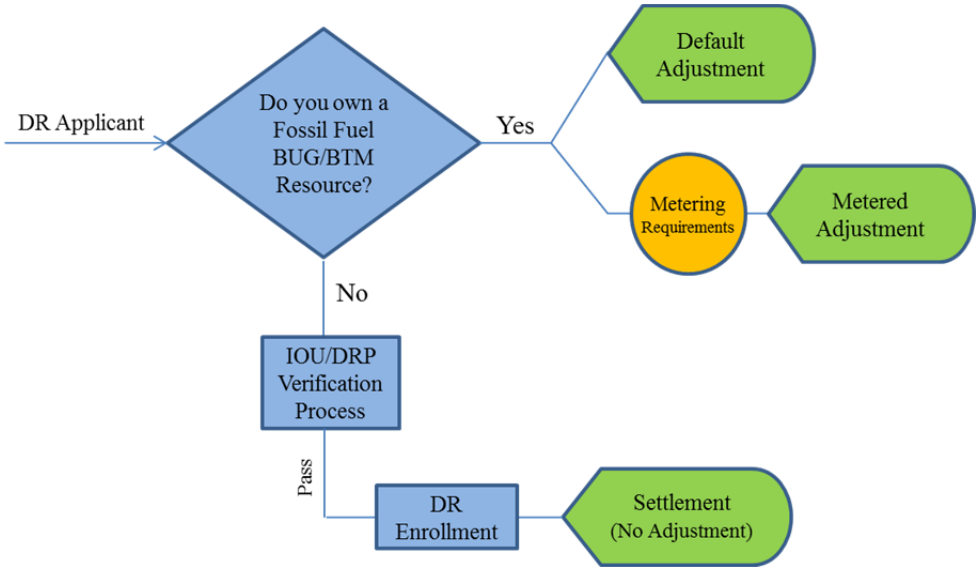
Energy Division recommends an approach similar to that taken in Resolution E-4728: Option D (Hybrid proration/attestation) with proration applied to non-residential customers and attestation applied to residential customers. While this option creates some risk that residential DR participants could renege on their commitment not to use their BUG units during DR events, that risk is outweighed by the cost to install meters on those customers. Option D captures non-BUG induced DR, while leaving it to the participant to decide on the specific method of proration (metering or BUG rated capacity).

A. **Exemptions to the Enforcement Mechanism:** PU Code Section 380.5 specifically exempts the following programs from policies set with regard to BUGs and DR: time-variant pricing including

but not limited to: time-of-use rates, critical peak pricing, real-time pricing and peak time rebates.

B. **Non-DRAM IOU-Third Party DR Contracts (AMP):** with regard to these contracts, the enforcement mechanism would be implemented by the third party DRP, but the IOU is responsible for ensuring via the contract that it has access to all data (DR performance and BUG meter data) to verify that the DRP has executed the enforcement mechanism in compliance with the policy. Additionally the same data may be accessible by the Commission should it decide to do its own verification analysis.

C. Process Flow for non-residential DR participants:



a) No BUG on Premises, with Verification

i. If a customer attests that there is no BUG present at the premises, the IOU/DRP must verify the information prior to executing a contract/tariff with the customer[20]. The verification process must be repeated bi-annually no later than March 30. If a customer obtains a BUG, it must inform the utility to initiate the proration process. Failure to provide the required information will result in the customer being removed from the respective demand response program/contract and deemed ineligible for all DR programs until the policy is complied with.

[20] IOUs/DRPs can verify that information either through site visits or cross examining data with AQMDs or SGIP administrators.

b) **BUG on Premises, with Proration**[21] Customers with BUGs have the option of choosing the proration method.

i. Default Adjustment

This option does not require metering[22]. In this option the final load drop will be adjusted based on the rated capacity of the BUG unit (to be verified by the IOU/DRP). If a customer is interested in a more accurate performance based incentive they have the option of choosing Metered Adjustment.

ii. Metered Adjustment

This option requires meter installation. Any customer who owns a fossil fueled resource on their premise and is interested in participating in DR without default adjustment must install and maintain metering and monitoring equipment at their own cost[23]. The metering system allows the IOU/DRP to determine the amount of net system load reduction that is Non-BUG assisted.

- **Energy and Capacity Incentive Adjustments (example):** The following example could be applied to the Capacity Bidding Program. Other methods may be necessary depending on the design of the specific DR program.

A. Energy Adjustment:

a. The calculated energy reduction is adjusted based on the <u>rated capacity of the BUG (Default Adjustment)</u> or the <u>BUG meter data (Metered Adjustment)</u> depending on the proration option chosen by the customer at the time of enrollment. The adjustment is incorporated into the IOU/DRP settlement process so that the portion of the energy reduction attributable to the BUG is not financially rewarded.

B. Capacity Adjustment:

a. Customer commits to an amount of DR load drop that is not BUG-assisted, and the capacity payment is based on that amount. The proration to the capacity payment is based on the <u>rated capacity of the Fossil-fueled Resource (Default Adjustment)</u> or the <u>Fossil-fueled Resource meter data (Metered Adjustment)</u>. If the final adjusted capacity value deviates by more than 10% from the customer's initial commitment as the non-

[21] Proration will ensure ratepayer-funded incentives result in expected levels of clean load reduction and that any fossil fuel generation during a demand response event is not compensated with DR incentives.

[22] This option is ideal for customers with smaller BUG units who want to participate in DR but prefer not to install meters.

[23] Requiring separate metering also has precedent in other subsidy programs. Participants in the Self-Generation Incentive Program ("SGIP") must install metering and monitoring equipment on SGIP facilities at the owner's expense, as a condition of receiving incentives. (Self-Generation Incentive Program Handbook (Jan. 2015), pp.60-64.)

BUG assisted load drop, then the customer's committed load drop for the following month will be adjusted to reflect the deviation. A customer can lower its DR commitment at any time within the program/tariff/contract permitted limits.

- **Other Requirements:**

The IOU/DRP is required to establish monitoring and enforcement infrastructures for calculating the net load reduction that is Non-BUG assisted. The details on how the IOUs will monitor and enforce its own programs and its contract with third party DRPs should be submitted to the Commission for approval.

IOUs must keep a record of all DR customers who own a BUG on their premises. The information should include

1. Owner's[24] info: Name, Address, Contact Info (phone/email)
2. Engine info: Make, Model, Year, Rated Brake Horsepower, Load
3. Service Account Number
4. Demand Response Program Info

- **Third Party DR Participating in CAISO Wholesale Markets**

As noted previously, the Commission has already adopted a BUGs-DR policy for contracts procured through the DRAM in Resolution E-4728. DRAM resources are required to participate in CAISO wholesale energy markets. However, there may be 3rd party demand response providers who are not selected for a DRAM contract, but may still choose to bid into CAISO markets via Rule 24/32[25]. Rule 24/32 (also known as 'direct participation') does not specifically address the use of BUGs and thus further development of new rules for Rule 24/32 may be needed. However, Energy Division does not anticipate many non-DRAM third-party demand response providers will be using Rule 24/32 to bid DR into wholesale markets initially[26]. We therefore recommend the Commission re-visit this issue if data indicates non-DRAM participation is substantial in 2016.

- **SGIP Resources-DR Dual Enrollment Eligibility:**

As noted previously, this issue is currently under consideration in R.12-11-005 and will be addressed in that proceeding.

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[24] If they own or operate a BUG (already or if they obtain one anytime during the program)

[25] Rule 24/32 is an IOU tariffed set of rules for third party demand response providers who seek to bid bundled load as DR in CAISO wholesale markets.

[26] D.15-03-042 found that there was no evidence that there are large numbers of utility customers who are ready to participate in third party direct participation (Finding of Fact 1). The decision also ordered the IOUs to delay enrollments in their Rule 24/32 registrations until after DRAM participants are ready to bid into CAISO markets (Ordering Paragraph 4).