BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U39M) for Approval of its Proposal for a Day-Ahead Real Time Rate and Pilot to Evaluate Customer Understanding and Supporting Technology U 39 M	Application No. 20-10-011 (Filed October 23, 2020)

RESUBMISSION OF MARGINAL GENERATION CAPACITY COST REPORT PURSUANT TO ADMINISTRATIVE LAW JUDGE SISTO'S JANUARY 14, 2022 RULING

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Dated: March 17, 2022

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On March 15, 2022, Pacific Gas and Electric Company ("PG&E") filed and served the "MGCC Pricing Formula for PG&E's Day-Ahead Hourly Real Time Pricing (DAHRTP) Rates, Report To Parties In California Public Utility Commission Dockets A.20-10-011 And A.19-11-019" (Study) in compliance with Administrative Law Judge Sisto's January 14, 2022 ruling ("ALJ ruling") setting March 15, 2022 as the filing date for the marginal generation capacity cost study ("Study") in both this proceeding, A.20-10-011, and PG&E's GRC II proceeding, A.19-11-019.

Subsequently PG&E has discovered an error that occurred as the Study was finalized for filing and service. In that process, "net load" was abbreviated to "NL". In order to correct that error, PG&E is refiling and reserving the Study with the correction. The corrected Study is attached to this pleading.

PG&E is serving the corrected Study with an exhibit cover sheet indicating that it is corrected.

Respectfully Submitted,

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Dated: March 17, 2022

Application: A.20-10-011
Exhibit No.: PG&E-24
Date: March 17, 2022
Corrected: March 16, 2022
Witnesses: Jan Grygier
Ben Guiterrez
Ryan Mann
John D. Wilson
Catherine E. Yap

PACIFIC GAS AND ELECTRIC COMPANY

COMMERCIAL ELECTRIC VEHICLE DYNAMIC RATE OPTION

MARGINAL GENERATION CAPACITY COST PRICING FORMULA FOR PG&E'S DAY-AHEAD HOURLY REAL TIME PRICING (DAHRTP) RATES, REPORT TO PARTIES IN CALIFORNIA PUBLIC UTILITY COMMISSION DOCKETS A.20-10-011 AND A.19-11-019

MGCC Pricing Formula for PG&E's Day-Ahead Hourly Real Time Pricing (DAHRTP) Rates

REPORT TO PARTIES IN CALIFORNIA PUBLIC UTILITY COMMISSION DOCKETS A.20-10-011 AND A.19-11-019

March 15, 2022

MGCC Study Participants:

- Jan Grygier and Louay Mardini, Pacific Gas and Electric Company (PG&E)
- John D. Wilson and Paul Chernick, Resource Insight, Inc. for the Small Business Utility Advocates (SBUA)
- Ben Gutierrez and Vanessa Martinez, CPUC Public Advocates Office
- Catherine Yap, Barkovich and Yap, Inc., for the California Large Energy Consumers Association (CLECA)
- Ryan Mann, Enel X for the Joint Advanced Rate Parties (JARP)

1 Executive Summary

Two ongoing proceedings of the California Public Utilities Commission (CPUC or Commission), Application (A.)20-10-011, Commercial Electric Vehicle (CEV) rates, and A.19-11-019, Pacific Gas and Electric Company's (PG&E) General Rate Case (GRC) Phase II, are developing rate schedules with a day-ahead, hourly real-time pricing (DAHRTP) rate component. As a result of a stipulation and related rulings in these two proceedings, several parties to those proceedings conducted this Marginal Generation Capacity Cost (MGCC) Study to research the design of a pricing formula to allocate PG&E's MGCC on an hourly basis. The hourly MGCC pricing formula is designed for use in a DAHRTP rate. The MGCC Study Participants recommend a formula that calculates much of the DAHRTP price from the value of net load, adjusted for temperatures affecting imported energy from areas outside the management of the California Independent System Operator (CAISO) (referred to as "ANL_T"). The remainder of the MGCC price component would be captured by a Flex Alert event "adder." It is appropriate to use a combination of ANL_T and Flex Alert events to determine hourly MGCC pricing because grid stress and reliability events may occur in a variety of load conditions.

High load or net load (load adjusted for wind and solar) days have a high probability of the CAISO issuing an Alerts, Warnings, and Emergencies (AWE) notification (AWE event), but not a 100 % probability. Other factors affect system reliability, and grid stress and reliability events do occur on days with low load or net load. For these reasons, the MGCC Study Participants evaluated alternative adjustments to net load, determining that:

- Consideration of temperatures in Arizona and the Pacific Northwest improved the precision of predicting the probability of the CAISO calling an AWE event; and
- A Flex Alert event "adder" of $0.25/kilowatt-hour (kWh) also contributes to the MGCC pricing because other factors beyond ANL_T can create stress in the grid and influence CAISO decisions to call an AWE event; this "adder" also leverages extensive publicity around Flex Alerts.

The ANL_T portion of the MGCC pricing formula is designed to collect the majority of the MGCC cost by using a sigmoidal (S-shaped) to relate this adjusted net load metric to an hourly price function. The hourly price function is referred to as PCAF-S to distinguish it from PG&E's original proposed Peak Capacity Allocation Factor (PCAF)-based function.[1]

In choosing a recommended MGCC pricing formula, the MGCC Study Participants considered both the accuracy of the signal (in terms of aligning with CAISO AWEs, which indicate operationally times of high grid stress), as well as the year-to-year variability expected under various versions of the MGCC signal. Some of the benefits of the recommended MGCC pricing formula, compared to PG&E's original proposal, are:

- Non-zero MGCC prices at lower adjusted net loads;

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1 The standard PCAF formula allocates capacity to hours in which a measure of load is above a threshold (here, 80% of the expected maximum annual hourly load), proportional to the amount the load exceeds that threshold.

- A maximum hourly MGCC price component (rather than increasing indefinitely at higher and higher net loads); and
- Lower year-to-year revenue variability.

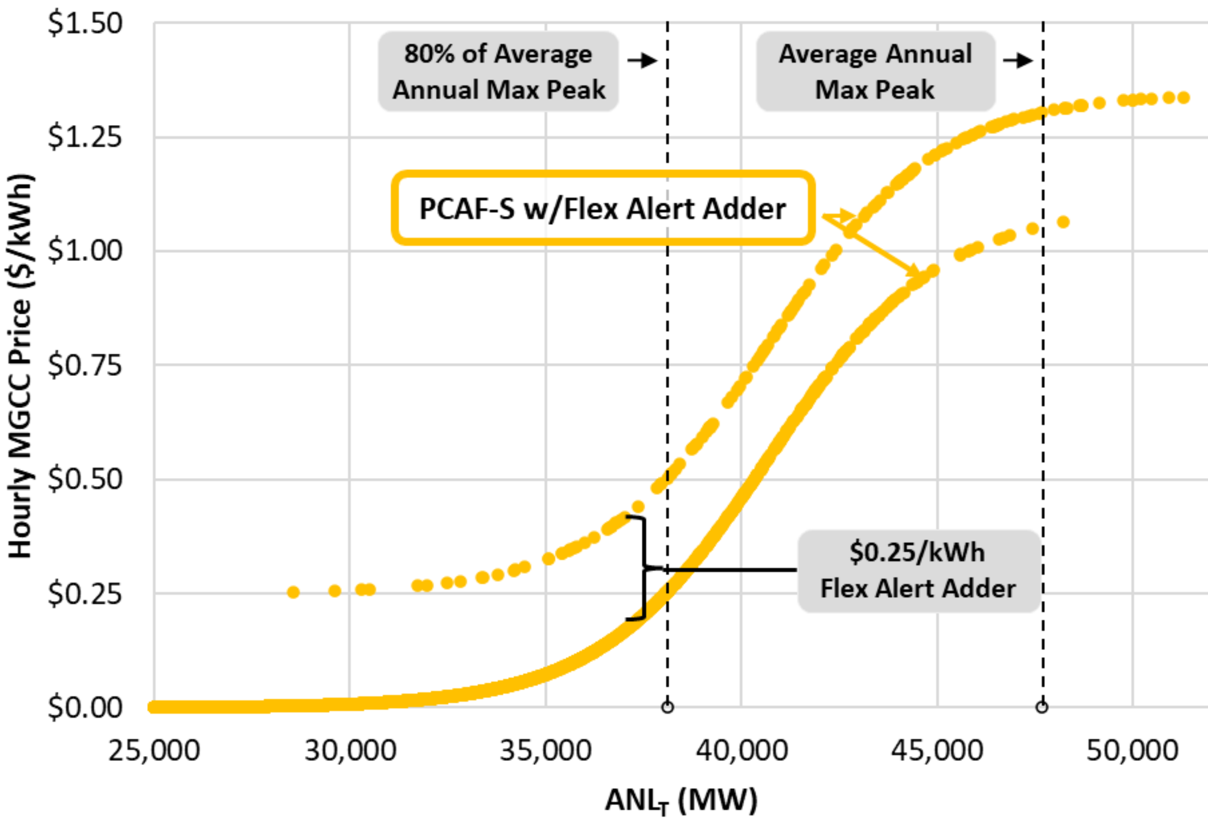
Low year-to-year variability in the MGCC portion of the DAHRTP rate is important because it reduces the likely magnitude of revenue over- and under-collections.

The MGCC Study Participants also evaluated potential bill impacts on a prototypical Schedule B-6 customer. The DARHTP rate would not substantially increase year-to-year variability in a customer's bill and it would provide a meaningful enhancement to the customer's "profit" from use of a battery storage device.

Accordingly, the MGCC Study Participants recommend the CPUC adopt the following formula for setting the MGCC price in PG&E's DAHRTP rate., illustrated in Figure 1 and defined in Equation 1. The hourly price is determined using the variables H (maximum price contribution from the hourly PCAF-S function of adjusted NET LOAD) and E (event-based adder), which are optimized to recover the total MGCC of $90.35/kilowatt-year (kW-year) in an average year, and the variables A and B are determined using logistic regression using historical data, as explained in Section 3.

Figure 1: Hourly MGCC Pricing Formula

Applied to Net Load and CAISO Day-Ahead (DA) Energy Prices for 2017-2021



Equation 1: Hourly MGCC Pricing Formula

$$\text{Hourly MGCC Price: PCAF-S}(ANL_T) = H / (1 + \exp(A - B * ANL_T)) + E * \text{Flex Alert}$$

$$\text{PCAF-S}(ANL_T < L) = 0$$

ANL_T is normalized[2]

$$E = \$0.25$$

$$H = \$1.097$$

$$A = 18.78$$

$$B = 23.72$$

$$L = 27{,}713 \text{ MW}$$

The MGCC Study Participants anticipate that the specific values for H, A, B, and L may be updated by PG&E prior to program launch, reflecting additional historical data or any updates to the MGCC price of $90.35/kW-year, using the methods described in this report. The value for E should only be updated if the CAISO updates the penalty price for ancillary services shortages.

The MGCC Study Participants are authorized to state that PG&E, Small Business Utility Advocates (SBUA), Public Advocates Office at the California Public Utilities Commission (Cal Advocates), California Large Energy Consumers Association (CLECA), and Joint Advanced Rate Parties (JARP) support the report and its recommendations, and urge the Commission accept the findings and recommendations of the MGCC Study. It is also hoped that other parties to A.20-10-011 (CEV rates), and A.19-11-019 (PG&E's GRC Phase II) will provide their support.

2 ANL_T is normalized using the formula: $(ANL_T – Min)/(Max – Min)$, where Min/Max are the minimum/maximum ANL_T values in the dataset. The normalized values of ANL_T used in Equation 1 range from 0 to 1.

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2.1 Tables

2.2 Figures

2.3 Equations

3 PROCEDURAL HISTORY

PG&E proposed to develop dynamic rates based on DAHRTP signals in two CPUC proceedings: A.20-10-011, CEV rates, and A.19-11-019, its GRC Phase II. The CEV proceeding went to hearing in June 2021 on numerous issues raised by PG&E's application. CPUC Decision (D.) 21-11-017 (November 18, 2021) in the CEV proceeding resolved most issues, but the issue of the appropriate allocation of MGCC to each hour was subject to a stipulation between parties that agreed to form an MGCC Study Working Group to collaboratively study the complex issues in greater depth (the MGCC Stipulation).[3]

In D. 21-11-017, the CPUC continued the CEV proceeding to provide time for completion of this MGCC Study, and Administrative Law Judge (ALJ) Sisto extended that time to March 15, 2022 by a January 14, 2022 ruling. At the January 26, 2022 Real-Time Pricing (RTP) hearings in the GRC Phase II proceeding (A.19-11-019), ALJ Sisto confirmed her direction that PG&E file and serve the same MGCC Study as a late-filed exhibit, and that any party from PG&E's GRC Phase II proceeding who is interested in commenting this study should do so through the proceedings scheduled in A.20-10-011, for administrative efficiency. This MGCC Study Report fulfills the requirements of D.21-11-017 and subsequent related rulings.

Most of the issues in PG&E's 2020 GRC Phase II were decided in D.21-11-016, but RTP rate design issues, including the issue of the appropriate allocation of the MGCC to each hour, were deferred to a separate track. On January 14, 2022, a settlement of most RTP issues was filed in A.19-11-019 (January 14 Settlement).[4] The parties are awaiting a Proposed Decision (PD) on the January 14 Settlement.

In addition, D.21-11-016 reserved the issue of a whether Property Tax Adder should be applied to the annual MGCC proposed by PG&E for a future decision. On January 21, 2022 PG&E and CLECA filed a stipulation regarding the property tax adder, and after no protests were filed on the stipulation, a PD accepting the stipulation was issued on February 11, 2022.[5] The earliest a Final Decision on the Property Tax Adder PD can be voted on by the Commission is March 17, 2022.

This document assumes that the annual MGCC of $76.35/kW-year specified in that PD will be maintained in the CPUC's Final Decision. The annual MGCC is increased by the 15% Planning Reserve Margin (PRM) and losses of 2.9% corresponding to primary voltage distribution service to yield a final expected annual capacity cost for primary voltage customers of $90.35/kW-year.

The methodology issues concerning development of the MGCC element for the hourly RTP rate are in both the GRC Phase II RTP proceeding A.19-11-019 and the CEV proceeding, A.20-10-011. In both proceedings, the MGCC RTP issues were deferred to a future phase of the proceeding. The MGCC RTP

3 A.20-10-011, Exhibit PG&E-20, Joint Stipulation on Study for MGCC Rate Design Issue (MGCC Stipulation).

4 A.19-11-019 Joint Motion of the Agricultural Energy Consumers Association, CLECA, California Solar and Storage Association, Enel X North America, Inc., Energy Producers and Users Coalition, Federal Executive Agencies, OhmConnect, Inc., Cal Advocates, SBUA and PG&E (U 39 E), For Adoption of Joint Settlement Agreement on RTP Issues Including Stage 1 Pilots (Jan. 14, 2022).

5 A.19-11-019, PD (Feb. 11, 2022).

rate issue is now set for hearings for May 18 to 20, 2022, in A.20-10-011.[6] This document is the MGCC Study described in Exhibit 20 of A.20-10-011, and required to be served by March 15, 2022, pursuant to the ALJ ruling issued January 14, 2022 in A.20-10-011.

Parties generally agreed that PG&E should offer a consistent DAHRTP rate design for both the CEV pilot participants and whatever eligible customer groups are offered an RTP rate as a result of a GRC Phase II decision. One additional party to the Phase II proceeding joined the parties to the CEV proceeding in the MGCC Study Working Group.

The MGCC Study Working Group includes five organizations represented by subject matter experts who have collaborated in the study on behalf of their respective organizations.

- PG&E – Jan Grygier, Louay Mardini and Matt Kawatani
- SBUA – John D. Wilson and Paul Chernick (Resource Insight, Inc.)
- Cal Advocates – Benjamin Gutierrez and Vanessa Martinez
- CLECA – Catherine Yap (Barkovich & Yap, Inc.)
- JARP – Ryan Mann (Enel X)

A number of other individuals from the five organizations also contributed substantially to the MGCC Study Working Group's work product. Throughout the text, the term "MGCC Study Participants" is meant to refer to a consensus interpretation, opinion or agreement reached among the individual representatives of each organization.

3.1 Proposals Set Forth in Testimony Regarding the Allocation of MGCC to Hours

The MGCC Study Working Group parties set forward positions in several rounds of testimony filed in both the CEV and GRC Phase II proceedings. These positions evolved in response to parties' mutual consideration of proposals and further research. A brief summary of the rate design approaches filed by four parties[7] follows.

3.1.1 PG&E

PG&E proposed to use its generation PCAF method based on Adjusted Net Load (ANL)[8] to determine the appropriate allocation of capacity cost to the DAHRTP prices for each hour of the year. PG&E's ANL/PCAF method includes a hydro variable in the definition of ANL and uses all weather year

6 The January 14 settlement in A.19-11-019, pp. 15-18, refers to the MGCC Stipulation (A.20-10-011, Exhibit 20) regarding the scope, approach, and schedule for a MGCC study to determine the structure for the Stage 1 RTP pilot rates' MGCC component. The January 14 settlement proposes that the litigation for the MGCC RTP rate component occur on a consolidated basis in the two proceedings.

7 CLECA did not address the allocation of MGCC in testimony.

8 ANL is equal to Net Load (gross load (GL) minus grid-scale wind and solar generation) minus hydro, nuclear, and other renewables. ANL is thus the amount of load that must be met by thermal generation, imports, energy storage, and nuclear.

scenarios in the calculation of the threshold and the "PCAF denominator."[9] PG&E initially proposed to multiply the hydro variable by a factor greater than one (as used in PG&E's Marginal Energy Cost (MEC) model from the GRC Phase II), but later suggested using a lower factor to take into account the fact that hydro generation typically shows lower variability year-to-year during grid stress conditions than during normal operations.

3.1.2 Cal Advocates

Cal Advocates proposed to reflect different hydro year assumptions than used by PG&E, by limiting the selection of weather years used to calculate both the PCAF threshold and the PCAF denominator in the MGCC allocation to those simulated weather years with similar hydro conditions to the current year. Cal Advocates also proposed allocating 13% of the MGCC to hours that reflect the CAISO issuance of a DA Flex Alert or DA Alert[10] with the remaining MGCC value (87% of total) assigned to hours based on PG&E's proposed PCAF methodology.

3.1.3 Small Business Utility Advocates

SBUA proposed to allocate the MGCC based on a combination of CAISO Alerts and Flex Alerts, CAISO Restricted Maintenance Operations (RMO) events, and an ANL/PCAF method based on PG&E's hydro assumptions or with Cal Advocates' hydro year modification, potentially using a different functional form for PCAF weighting above the threshold than PG&E's linear function, and/or using a different threshold than PG&E's 80% of scenario-averaged maximum annual ANL.

3.1.4 JARP (California Solar and Storage Association, Enel X)

JARP did not oppose PG&E's proposed MGCC allocation methodology but also supported a collaboration among parties to address allocation issues arising in the proceeding.

3.2 Scope of MGCC Working Group Study

The MGCC Stipulation established the scope of the Working Group study as:

> *[to] determine the fit between alternative formulations of hourly MGCC... and capacity shortfall (reliability) metrics. The primary purpose of a real-time capacity price signal is to accurately reflect temporal (hourly) variations to the risk that there will be insufficient capacity to serve demand – and thus variations in the capacity costs at the margin of serving incremental load.*[11]

In order to develop the formulations of hourly MGCC and capacity shortfall metrics, the MGCC study will

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[9] The "PCAF denominator" is equal to the expected sum of load above the threshold over a set of "weather years" for which load and renewable generation is matched to the weather in that calendar year.

[10] Cal Advocates proposed to assign 13% of the MGCC to the hours during which CAISO issues a day-ahead Flex Alert or alert (CAISO alert) and only for the hours between 3-9pm for which PG&E's PCAF-based capacity prices do not meet or exceed a certain threshold, possibly with limits on the minimum and maximum number of hours called in each calendar year.

[11] MGCC Stipulation, p. 5.

analyze the relationship of the following variables to the condition of the CAISO grid: 1) hydro year conditions, 2) the definition and weighting of the hydro variable in the calculation of Adjusted Net Load (ANL), 3) CAISO restricted maintenance operations (RMO), 4) day-ahead CAISO Flex Alerts and CAISO alerts events, 5) other CAISO warning and emergency events, 6) the Peak Capacity Allocation Factor (PCAF) threshold [that identifies PCAF hours], and 7) the functional form of PCAF weighting above the PCAF threshold.[12]

And finally, the MGCC Study will

help to identify the appropriate level of inter-annual variation in the DAHRTP pilot rate's MGCC price element. Parties' MGCC proposals result in differing levels of intra- and inter-annual variation in capacity prices. By comparing the various proposals to reliability metrics and determining which proposals produce the best fit, the Study could indicate what level of intra- and inter-annual variation is most appropriate and would most accurately capture varying levels of capacity shortfall risk within a year and across multiple years.[13]

While the MGCC Study is mainly focused on the hourly MGCC price component, the MGCC Study also considers interactions with the other two components of the DAHRTP price, the MEC and the Revenue Neutral Adder (RNA). The MGCC Study Participants did not evaluate any alternatives to the MEC and RNA components, which have been resolved by D.21-11-017 (November 18, 2021) in the DAHRTP-CEV proceeding. The MGCC Study Participants assumed for purposes of this study that those issues would be resolved similarly in the GRC Phase II proceeding.

12 MGCC Stipulation, pp. 1-2.

13 MGCC Stipulation, pp. 5-6.

4 DATA SOURCES

Ideally, the design of the hourly MGCC price component would rely primarily on modeled forecast data to be best aligned with the expected mix of resources that underlie those generation costs. Forecast data also provide useful estimates of low-probability, high salience reliability events. However, forecast data do not incorporate information from CAISO AWEs, which provide a direct indication of hours in which the CAISO determines that there is stress on the grid, i.e., an elevated risk of outages.

Fortunately, the incidence of rolling blackouts is normally very low, as evidenced by the only three Stage 3 Emergencies that occurred between 1998 and 2021.[14] Modeled forecast data does not include a direct measure of rolling blackouts, but instead provides a statistical measure of Expected Unserved Energy (EUE), which measures the expected loss (or curtailment) of load in units of megawatt-hours (MWh). The difference between historical and modeled forecast reliability measures demonstrates both the necessity and challenge of using both types of data in this study.

From a historical perspective, the MGCC Study Participants recognize that the CAISO issues other notices prior to the occurrence of a Stage 3 Emergency that are available for indicating increasing levels of grid stress. Based on analysis, the Study Participants have hypothesized that RMOs indicate moderate risk of bad outcomes, Alerts and Flex Alerts represent elevated risk, while CAISO Warnings and Stage Events represent greatly increased risk ultimately resulting in actual load drop on the system, as discussed in Section 4.1.3 below.

A similar pattern of increasing levels of grid stress is also available in modeled forecast data. EUE is the primary measure of capacity shortfall and is assumed to be linear; in other words, an EUE of 100 MWh in an hour (or year) is assumed to be ten times as costly to customers and the California grid as an EUE of 10 MWh. Other measures of grid stress are non-spin reserve shortfall, upward reserve shortfall, and calls on demand response (DR) resources. While there is not a one-to-one relationship between historical and modeled forecast reliability metrics, the MGCC Study Participants concluded that the statistical similarities could be leveraged to develop a useful model of grid stress.

However, as discussed below, the MGCC Study Participants determined that the available forecast data were generally not suitable for use in a rate design context. While suitable modeling is likely feasible, the MGCC Study did not have access to model data that would allow for modeled forecast reliability metrics to be described in a manner that could be used directly to design a DAHRTP rate. Some of the available forecast data were used as benchmarks, or comparator data, for example to indicate the general level of year-to-year variability expected for capacity-related costs.

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14 A Stage 3 Emergency is the highest risk event in the CAISO's AWE system and indicates that load interruptions (blackouts) are necessary. There were 38 Stage 3 Emergencies in 2001, the "California Energy Crisis" year. These emergencies were at least partially due to manipulation by market entities that has since been rendered significantly less likely.

4.1 *Historical Data*

4.1.1 Extended MEC Data

As part of its marginal cost showing in its Phase 2 proceeding, A.19-11-019, PG&E had prepared a set of data incorporating hourly load, generation and price information for January 2012-December 2019. This dataset was extended to the period May 2010-December 2021 and simplified to remove the MEC model calculations to reduce file size and the proprietary portions of the dataset. The extended data set incorporates historical hourly day ahead (DA) prices, real-time (RT) prices, CAISO total load, CAISO net load, adjusted net load, temperature data for surrounding areas, quantity of load met by various resource types, and other pertinent information. The MGCC Study Participants used this historical data in most historical analyses.

4.1.2 Alternative Load Metrics

The MGCC Study Participants analyzed six different load metric candidates for use in the DAHRTP design. Because most energy and capacity is procured to meet CAISO system-wide requirements, rather than local PG&E resource needs, all six candidates are based on total CAISO system load.

1. **Gross Load (GL)** – Excludes behind-the-meter (BTM) generation
2. **Net Load (NL)** – Also excludes interconnected solar and wind generation
3. **Resource-Adjusted Net Load (ANL_R)** – NL adjusted to exclude other Greenhouse Gas (GHG)-free resources, including hydroelectric, nuclear, biomass/biomass and geothermal
4. **Temperature-Adjusted Net Load (ANL_T)** – NL adjusted to account for non-CAISO system conditions, such as imports availability, using weather stations at Phoenix Airport (PHX) and Seattle-Tacoma Airport (SEA)[15]
5. **ANL_{RT}** – Combines the adjustments for NL, ANL_R and ANL_T into a single metric
6. **ANL_{RTG}** – Combines GL, ANL_R and ANL_T into a single weighted average metric

Note that in the remainder of this document, the term "net load" (without capitalization) refers to load metric candidates 2 through 6 generically, not just to candidate 2, above.

4.1.3 Alerts, Warnings, and Emergencies Data

The MGCC stipulation approved in D.21-11-017 (November 18, 2021) noted, "It would also be valuable to the Study to obtain more detailed information from CAISO regarding the standards that it applies to initiate an Alert, Warning or Emergency (AWE) event, both in general and with respect to historical events." MGCC Study Participants requested this information during a conference call on July 13, 2021, but the CAISO declined to provide information beyond what is published on its website.[16]

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15 The same temperature adjustments were used in the MEC model developed by PG&E in its 2020 GRC II testimony, A.19-11-019, Exhibit PG&E-2, Ch. 2, pp. 2-29 to 2-31, Marginal Generation Costs.

16 Overall procedures for calling AWEs are listed in Operating Procedure 4420, available at http://www.caiso.com/rules/Pages/OperatingProcedures/Default.aspx. However, that document does not detail specific conditions that can trigger an AWE. A list of AWEs since 1998 is at http://www.caiso.com/Documents/AWE-Grid-History-Report-1998-Present.pdf.

The MGCC Study Participants built on data assembled by Cal Advocates and SBUA for their testimonies, and created a complete list of each AWE event, the time it was called, and the dates and hours that it was in effect. AWEs designated by CAISO as restricted to Southern California were discarded. Most of those designations occurred as a result of the restrictions on the availability of the Aliso Canyon gas storage facility while natural gas supplies remained plentiful on PG&E's system.

The MGCC Study Participants used historical AWE event data as a means of determining the extent to which the six candidate load metrics correlate with system stress or capacity inadequacy. AWE event data published by the CAISO turned out to be incomplete (e.g., missing the time of the announcement) or inconsistent with press releases, social media announcements, or other information published by the CAISO. The MGCC Study Participants have used multiple information sources to check the data in the AWE list and ensure its accuracy. Overall, relatively few AWE events have been called by the CAISO over the past decade, with some years having very few events called, as shown in Table 1.[17]

The various AWE event types are described in CAISO Operating Procedure 4420, as summarized below.

- **Flex Alert** – Flex Alerts are part of a consumer educational and alert program for voluntary conservation of electricity during heat waves and other challenging grid conditions. Flex Alerts are most effective when issued a day or more in advance of "operating day," but may be issued with little or no advance notifications during sudden grid emergencies.
- **Restricted Maintenance Operations (RMO) notice** – RMO notices are issued when CAISO determines it is necessary to cancel or postpone any/or all work to preserve overall System Reliability. Operators are notified to only approve outages of transmission and/or generation facilities that will have no potential negative effect on system reliability, and to utilize exceptional and manual intertie dispatch as necessary. RMO notices are typically issued for an extended duration, which includes some hours with low DA energy prices. CAISO Operating Procedure 4420B describes the procedure for determining RMO event durations, but the detailed description of that procedure is not publicly available. RMOs can be issued one or more days ahead or on the operating day.
- **Alert** – An Alert is a type of Energy Emergency that is a precursor to Stage 1 emergencies, as well as a trigger to inform utilities to consider activating Emergency Load Reduction Programs (ELRP). The MGCC Study Participants found that when an Alert was issued, the CAISO almost always issued a Flex Alert. For this reason, the MGCC Study Participants have analyzed these two AWE events in combination, abbreviating references to them as Flex Alerts and Alerts (FA/A) Events. Going forward, CAISO has specified that Alerts will always be issued by 3 p.m. on the day before the operating day.
- **Warning** – The CAISO declares a Warning event when its real-time analysis forecasts that one or more hours may be energy deficient with all available resources in use or forecasted

17 The CAISO list of AWEs extends back to 1998 when the CAISO was formed. AWEs prior to 2010 were not considered in this study for two reasons: 1) the hourly load and generation data needed to construct the alternative load metrics discussed above are not available prior to April, 2010, and 2) the market prior to 2010 had a different structure (with a Power Exchange running a day-ahead market, and bilateral hour-ahead markets). Furthermore, the 2001 Energy Crisis resulted in a large number of AWEs due to factors such as market manipulation that are unlikely to be repeated and would be impossible to model.

to be in use and the CAISO is concerned about sustaining its required Contingency Reserves. A Warning event may trigger decisions to dispatch DR and non-market generation capacity resources. Going forward, Warnings and Emergencies (W/E) will always be called on the operating day.

- **Emergency, Stage 1** – The CAISO declares a Stage 1 Emergency event when all available resources are in use. Additional DR, load reduction, and generation resource programs and activities are taken progressively.
- **Emergency, Stages 2 and 3** – The CAISO declares a Stage 2 or 3 Emergency event when it anticipates it can no longer meet energy requirements and is energy deficient. During Stage 2, the CAISO escalates Stage 1 activities and makes arrangements to drop firm load. Firm load interruptions occur during Stage 3.[18]

The MGCC Study Participants did not evaluate CAISO transmission emergencies because the DAHRTP price is restricted to generation costs only.

Table 1: AWE Event-Days 2010-2021[19]

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total	Avg
RMO	9	4	8	3	2	9	6	19	5	2	17	16	**100**	**8.3**
Flex Alert	-	2	2	3	1	2	2	4	2	1	10	8	**37**	**3.1**
Alert	-	-	-	-	-	1	-	-	-	-	9	-	**10**	**0.8**
Warning	1	1	-	-	1	1	-	-	-	1	7	4	**16**	**1.3**
Stage 1	-	-	-	-	-	-	-	1	-	-	-	-	**1**	**0.8**
Stage 2	-	-	-	-	-	-	-	-	-	-	6	1	**7**	**0.6**
Stage 3	-	-	-	-	-	-	-	-	-	-	2	-	**2**	**0.2**
Warning or Emergency	1	1	-	-	1	1	-	1	-	1	7	4	**17**	**1.4**

The MGCC Study Participants could not fully analyze AWE event conditions because the detailed description of CAISO Operating Procedure 4420B, the AWE Guide, is not publicly available; the CAISO has not shared much public detail regarding the factors that it considers when deciding to issue an AWE.

The MGCC Study Participants noted that RMOs were issued on a multiple day basis because they are directed at generating resources that require significant advance notification because of potentially long startup times. However, from a reliability perspective the occurrence of RMO hours during the

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18 CAISO, Operating Procedure No. 4420, Version 13.2 (Oct. 21, 2021). Available at: http://www.caiso.com/rules/Pages/OperatingProcedures/Default.aspx.

19 As the CAISO sometimes calls events that span more than one day, an event-day is defined a day with an AWE event (of any number of hours). The primary source for these data is CAISO's AWE Grid History Report, available at: http://www.caiso.com/Documents/AWE-Grid-History-Report-1998-Present.pdf. CAISO press releases, social media, and other publicly available information were used to correct data irregularities and fill in missing data.

off-peak periods is fairly meaningless—there is no suggestion that additional generation resources would result in the CAISO shortening RMO events to just the peak periods. Therefore, the MGCC Study Participants concluded that not all RMO hours should be considered.

The MGCC Study Participants concluded that the development of the MGCC pricing formula would only consider RMO event hours from 3 PM to 10 PM. Data supporting this decision can be found in Finding 5.6, where Figure 6 and Figure 7 illustrate the hourly incidence of Flex Alerts and W/E events. Focusing on the 2017-2021 time period, almost all of those events occurred between the hours of 3 PM to 10 PM.[20] In contrast, RMO events often begin much earlier than 3 PM – in fact, Figure 7 omits many RMO event hours that occurred before 10 AM. In addition to those data, the Participants also observed that the 3 PM to 10 PM period corresponds to PG&E's mid-peak and on-peak hours, except for the hour between 10 PM and 11 PM.

As noted above, Alerts are always issued on a DA basis and for the period analyzed in Table 1, they have always occurred on the same day as a Flex Alert, so they are referred to jointly as FA/A events. For purposes of analysis, Warning and Emergency events (which are issued day-of), are occasionally combined and may be referred to as W/E events. A total for these events is provided in Table 1 since a Warning is not necessarily issued prior to an Emergency.

4.1.4 Cutoff Time for Notifications to Participants

The MGCC Study Participants learned from PG&E staff that PG&E would like to communicate the DAHRTP price to pilot participants before approximately 4 PM each day. There is concern that a later notification may be significantly less convenient for participants.

Historically, CAISO has called a significant number of FA/A events between 4 PM and 6 PM. However, the MGCC Study Participants anticipate that due to a more formal link between FA/A events and DR programs, particularly for the ELRP, CAISO is likely to call almost all FA/A events prior to 4 PM.

Accordingly, for purposes of this study, the MGCC Study Participants found it reasonable to interpret RMO or FA/A events called before 6 PM as DA events for purposes of analysis. The Participants anticipate that there will be few, if any, events called between 4 PM and 6 PM. The Participants expect that PG&E will communicate the DAHRTP price to pilot participants before approximately 4 PM each day, but that from an analytic point of view, a 6 PM cutoff time should be used for historical data.

Accordingly, in certain analyses, a distinction is made between FA/A and RMO events that are called after 6 PM on the DA. Where making a distinction based on this historical 6 PM cutoff, events will be classified as either as DA or as Evening and/or Day-Of (EDO).

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20 Those Flex Alerts and W/Es in the 2017-2021 period that occurred earlier than 3 PM had load below the 99th percentile, suggesting that those event hours may have been included because the CAISO determined that it was important to address a more severe condition later in the day by initiating the event early. Moreover, while some of the Warnings in Figure 6 and Figure 7 begin in HE 13 and extend past 10 PM, the descriptions of those extended Warnings reference anticipated reserve shortfalls between the hours of 3 PM and 10 PM.

4.2 Modeled Forecast Data

4.2.1 Strategic Energy Risk Valuation Model Forecast Data

The Commission's Energy Division uses the Strategic Energy Risk Valuation Model (SERVM), a probabilistic reliability and production cost model, to validate the reliability, operability, and emissions of resource portfolios.[21] The Energy Division designed a 38 million metric tons (MMT) Core Portfolio Preferred System Plan to produce the 2021 Transmission Planning Process (TPP).

Evaluation of a resource portfolio by SERVM is configured for specific study years using a range of future weather, economic output, and unit performance (outages) assumptions. The 2021 TPP SERVM evaluation includes the following assumptions:

- **Study years:** Load and generation resource forecasts for 2022, 2026 and 2030
- **Weather:** Twenty weather years (1998-2017)[22]
- **Economic output:** Load forecasts varied by -2.5%, -1.5%, 0%, +1.5% and +2.5% the forecasted load
- **Unit performance:** Simulation of hourly economic unit commitment and dispatch using 50 stochastic draws of possible outages
- **Import constraint:** Imports are constrained to a level that cannot exceed 4,000 megawatts (MW) from 4 pm to 10 pm, June through September[23]

Modeling twenty weather years with five load forecast variations results in 100 cases for each forecast year, with each SERVM case representing 50 random stochastic draws of possible generation and transmission system outages. SERVM outputs include forecasts for a number of variables; for purposes of the MGCC Study, four Grid Stress metrics were identified as variables of interest: (1) the hourly amount of EUE, shortages in (2) Non-Spin Reserve and (3) Upward Reserve resources,[24] and dispatches of (4) reliability DR.

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21 The following description of SERVM and its application by the Energy Division is found in Energy Division presentations: SERVM Production Cost Modeling Results (Dec. 17, 2021), available at ftp://ftp.cpuc.ca.gov/energy/modeling/IRP_PSPo_2020IEPR_HEV_SERVM_final.pdf; and Reliability and GHG Modeling Results (August 17, 2021), available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2019-2020-irp-events-and-materials/psp-servm-ruling-presentation.pdf.

22 It is not possible to directly match forecast and historical data based on weather year because the forecast loads and generation data differ substantially from the loads and generation that occurred in the actual historical year. For example, it is not reasonable to assume that an AWE event that occurred on August 1, 2015 would also occur on August 1 in the 2022 SERVM forecast using the 2015 weather year, because there would be significantly more solar and short-duration energy storage resources in the SERVM run, as well as fewer gas-fired resources.

23 CPUC Energy Division, Reliability and GHG Modeling Results, Aggregated Load Serving Entity (LSE) Plans, 38 MMT Core Portfolio (Aug. 17, 2021), Energy Resource Modeling Team, p. 23.

24 SERVM refers to Non-Spin resources as Quick-Start resources. Upward Reserve resources are the sum of Regulation Up plus Spinning Reserves.

The Energy Division provided the MGCC Study Participants several sets of SERVM forecast data, as summarized in Table 2. Energy Division's practice is to retain summary data for all 100 cases and detailed hourly data for only ten cases. No details are retained that can be attributed to the individual stochastic draws. It was understood that the ten cases with detailed hourly data are supposed to be those with the highest EUE. However, as shown in Table 3, hourly data were retained for only six of the ten highest-EUE cases for the 2026 forecast with the remaining four cases corresponding to very low EUE levels.[25]

Table 2: SERVM Forecast Cases Provided by the Commission's Energy Division

Dataset	2022	2026	2030
Annual Summary Data – 100 Cases	High-load Sensitivity Case	Base Case	Base Case
Hourly Data – 10 Cases	Base Case	Base Case	Base Case

25 The ten detailed hourly cases for the 2022 forecast also appears to include some cases with EUE levels that are not very high. However, since the ten detailed hourly cases are not comparable to the 100 summary data cases, it is impossible to determine whether the 2022 hourly cases did or did not represent the highest-EUE cases.

Table 3: Hourly Data Availability for 2026 SERVM Forecast Cases

Case Number	Load Forecast	Weather Year	EUE	Hourly Data Retained	Case Number	Load Forecast	Weather Year	EUE	Hourly Data Retained
99	2.5	2017	9,410		18	-1.5	2001	-	
97	1.5	2017	5,806		**20**	-2.5	2001	-	
44	2.5	2006	5,104	Yes	**21**	0	2002	-	
89	2.5	2015	2,803	Yes	**22**	1.5	2002	-	
87	1.5	2015	2,398	Yes	**23**	-1.5	2002	-	
42	1.5	2006	1,904	Yes	**25**	-2.5	2002	-	
96	0	2017	1,201		**26**	0	2003	-	
4	2.5	1998	998	Yes	**27**	1.5	2003	-	
41	0	2006	802	Yes	**28**	-1.5	2003	-	
74	2.5	2012	513		**29**	2.5	2003	-	
47	1.5	2007	340		**30**	-2.5	2003	-	
98	-1.5	2017	308		**31**	0	2004	-	
84	2.5	2014	251		**32**	1.5	2004	-	
43	-1.5	2006	241		**33**	-1.5	2004	-	
72	1.5	2012	217		**34**	2.5	2004	-	
45	-2.5	2006	207		**35**	-2.5	2004	-	
49	2.5	2007	169		**36**	0	2005	-	
2	1.5	1998	153		**37**	1.5	2005	-	
82	1.5	2014	120		**38**	-1.5	2005	-	
76	0	2013	117		**39**	2.5	2005	-	
86	0	2015	116		**40**	-2.5	2005	-	
94	2.5	2016	95		**48**	-1.5	2007	-	
100	-2.5	2017	70		**50**	-2.5	2007	-	
71	0	2012	60		**51**	0	2008	-	
73	-1.5	2012	31		**52**	1.5	2008	-	
17	1.5	2001	28		**53**	-1.5	2008	-	
14	2.5	2000	23		**54**	2.5	2008	-	
88	-1.5	2015	16		**55**	-2.5	2008	-	
3	-1.5	1998	15	Yes	**56**	0	2009	-	
91	0	2016	10		**57**	1.5	2009	-	
12	1.5	2000	10		**58**	-1.5	2009	-	
78	-1.5	2013	9		**59**	2.5	2009	-	
46	0	2007	5		**60**	-2.5	2009	-	
19	2.5	2001	5		**61**	0	2010	-	
79	2.5	2013	4		**62**	1.5	2010	-	
77	1.5	2013	4		**63**	-1.5	2010	-	
81	0	2014	4	Yes	**64**	2.5	2010	-	
24	2.5	2002	2	Yes	**65**	-2.5	2010	-	
83	-1.5	2014	0	Yes	**66**	0	2011	-	
1	0	1998	-		**67**	1.5	2011	-	
5	-2.5	1998	-		**68**	-1.5	2011	-	
6	0	1999	-		**69**	2.5	2011	-	
7	1.5	1999	-		**70**	-2.5	2011	-	
8	-1.5	1999	-		**75**	-2.5	2012	-	
9	2.5	1999	-		**80**	-2.5	2013	-	
10	-2.5	1999	-		**85**	-2.5	2014	-	
11	0	2000	-		**90**	-2.5	2015	-	
13	-1.5	2000	-		**92**	1.5	2016	-	
15	-2.5	2000	-		**93**	-1.5	2016	-	
16	0	2001	-		**95**	-2.5	2016	-	

4.2.2 Limitations of SERVM Forecast Data

There were several limitations to the SERVM forecast data provided by the Energy Division. First, the hourly data cases do not represent an ideally constructed statistical representation of the relationship between reliability, load, and generation.

- Each case represents the average of 50 stochastic model iterations. While suitable for many purposes, this averaging process conceals a certain amount of statistical variation that would be useful for analysis.
- Energy Division retained, and made available, hourly data for only ten of the 100 cases for each forecast year.
- Energy Division confirmed by email on November 23 that the ten cases retained are not the cases with the highest EUE; it is unclear how the Energy Division selected the ten cases.
- For the 2022 forecast year, two of the ten cases included very unusual results that do not appear in any of the 2026 or 2030 hourly cases, nor in the summary results from the 100 2022 high-stress cases, thus, the Study Participants decided to exclude these two cases from the analysis.
- For the 2022 forecast year, the summary data for the 100 cases are from a different (high-load sensitivity) model run than the ten supplied hourly cases. This makes it difficult to understand how the hourly cases relate to the full 100 case SERVM analysis.

Second, Energy Division did not provide all SERVM data that could have been useful for completing the study. Specifically, Energy Division redacted Operating Reserve Demand Curves and pricing data from the output files due to concerns about its validity. The MGCC Study Participants understood the concerns of Energy Division, but this decision resulted in a need to conduct further research to obtain alternate references.

Third, and most significant, the 4,000 MW import limit during the summer peak period created an insurmountable challenge to the use of the SERVM data to directly inform the rate design. During hours in which the import limit is effective, the model indicates a corresponding increase in thermal dispatch. This results in an increased probability of EUE during hours in which the modeled import limit is in effect. While the intent of the summer peak period import limit is to reflect existing RA contracts and capture the import limitation experienced during recent summer months, imports during June-September from 4-10 PM during 2020 and 2021 have actually exceeded 4,000 MW in 85% of the hours in which the CAISO GL was above 37,000 MW (with an average over those hours of 6,160 MW)—and for 5-10 PM imports exceeded 4,000 MW in *all* of the high-load summer hours.[26]

Furthermore, the import limit is not sensitive to load conditions that could actually constrain imports. During summer peak hours when CAISO net load is relatively high, modeled imports are near 4,000 MW – regardless of the level of load or net load in non-CAISO regions, which may be low due to relatively mild weather or high renewable generation, or high due to very hot conditions, especially close to sunset.

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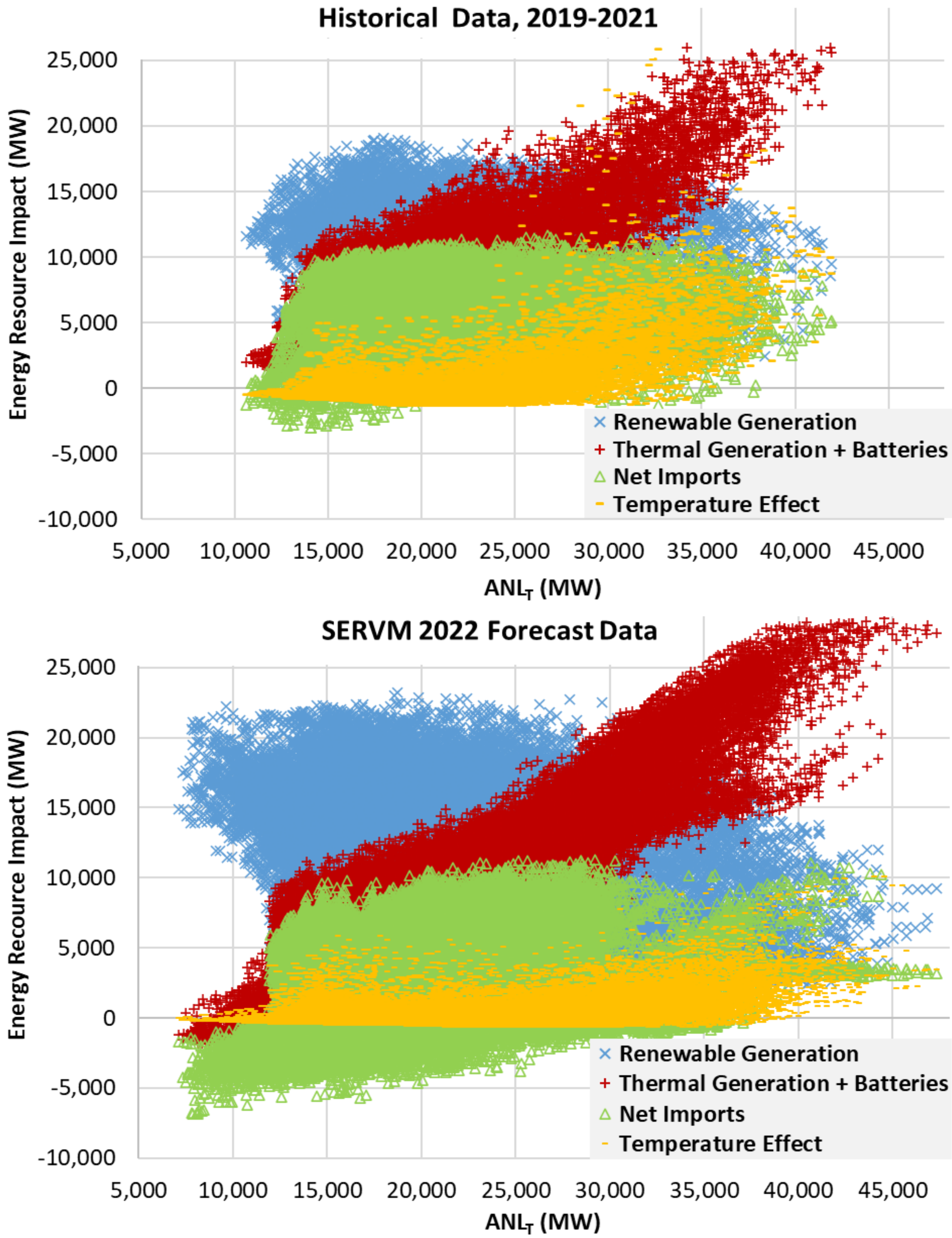
26 MGCC Study Participants recognize that historical data may not reflect future import levels and import patterns.

The differences between the historical and model forecast data are illustrated in Figure 2, below.

Figure 2: Energy Resource Impact, Comparison of Historical and Modeled Forecast Data



Some of the differences shown in Figure 2 are to be expected. Renewable generation is higher in the forecast model due to assumed continued renewables buildout. The higher renewables level results in increased net exports (illustrated as negative imports at low loads). However, a "spike" in net imports is visible at high loads; the spike is a result of the 4,000 MW import ceiling in summer peak hours, and only appears in the model forecast data.

As a result of the potential shifts in hourly EUE and insensitivity of imports to weather conditions, the MGCC Study Participants determined that the reliability metrics with temperature adjustments could not be used. The Participants agreed that one consequence of the 4,000 MW import limit is that EUE may be relatively overstated or understated on an hourly basis. In general, SERVM runs with or without an import limit should have roughly the same total EUE since the resource mix is selected to achieve a reliability target (usually expressed as loss of load expectation). The use (or non-use) of an import limit will affect the distribution of EUE across the year, with some hours having elevated EUE and others having reduced EUE.

When net load is high in non-CAISO regions, which would reduce CAISO import availability, the 4,000 MW import limit may reasonably represent actual conditions.[27] However, when net load is low in non-CAISO regions, the artificial 4,000 MW import limit may underestimate CAISO imports and result in relatively *overstated* EUE for those hours. In turn, because total EUE is driven by the reliability target, overstating EUE in some hours likely means that some high-load hours will have relatively *understated* EUE.

Even more important than the potential shift in EUE hours for the MGCC Study rate design effort is that the 4,000 MW SERVM import limit removes the temperature-dependence of import availability during high net load hours. As shown in Figure 2 for the 2022 forecast case on the right, during high net load hours, imports are almost always 4,000 MW, irrespective of the modeled load impact due to non-CAISO temperatures ("Temperature Effect").

As explained in Finding 5.4, the MGCC Study Participants agreed that ANL_T is the net load metric that is best associated with AWE events because the use of forecast temperature data for non-CAISO regions helps to predict the availability of imported power. The import limit included in SERVM modeling removed any significant variation in imported power during summer peak hours, resulting in hourly SERVM results that showed no relationship between temperature and grid stress. For this reason, it was not possible to use the SERVM data to conduct an hourly analysis of grid stress using the most accurate load metric (ANL_T).

4.2.3 Grid Stress Metrics in SERVM Forecast Data

Although the MGCC Study Participants did not use the SERVM data due to the shortcomings in the datasets discussed in Section 4.2.2, the Participants determined that the modeled forecast data includes four reliability metrics that could potentially be used in the future to refine the hourly MGCC price curve. If inconsistencies identified in Section 4.2.2 were addressed, including more dynamic

27 MGCC Study Participants understand that the SERVM Import constraint was chosen to model relatively conservative possible future conditions in a planning context, and that CAISO determined the constraint to be appropriate for the use case for which it was designed.

modeling of imports during the summer peak period,[28] then a Grid Stress metric could be developed using SERVM forecast results to inform the hourly MGCC price curve.

The MGCC Study Participants see some advantages to using hourly SERVM data to verify or refine the hourly MGCC prices in the future. Use of the SERVM data to refine the MGCC price curve after the pilot is completed might be beneficial because the SERVM dataset includes assumptions (e.g., loads, generation resource mix) that are meant to represent future conditions (e.g., 2022 and 2026) that are more closely aligned with prevailing conditions when the rate would be implemented than historical CAISO events data. In addition, the SERVM production cost modeling results include a high degree of hourly variability across several metrics that represent a range of reliability risk levels, which theoretically makes it a useful dataset for predicting hourly changes in system capacity costs.

However, as demonstrated in Finding 5.7.3, the reliability metrics in SERVM forecast data exhibit considerable inter-annual variability. Therefore, formulating a pricing function based on the single Grid Stress metric, as discussed below, would need to be tempered so as to keep the interannual variability to a reasonable level.

The SERVM forecast data includes four outputs that indicate increasing levels of grid stress and reliability impacts: Upward Reserve shortfall, Non-Spin Reserve shortfall, dispatch of reliability DR, and EUE, as discussed in Section 4.2.1. The two reserve shortfalls are associated with types of ancillary services. EUE corresponds to energy deficiency and firm load interruptions (Stage 2 and 3 Emergencies). For convenience, these four outputs are collectively referred to as the reliability metrics.

If SERVM forecasts were developed with a refined (or removed) summer peak import constraint, it would be possible to develop a function to relate ANL_T to the reliability metrics by weighting each of the reliability metrics by its relative cost to the system (price) and combining the four weighted reliability metrics into a single Grid Stress metric. The MGCC Study Participants identified two possible methods for determining the weight of each reliability metric.

First, SERVM includes price-related outputs that might possibly provide a reasonable basis for weighting the reliability metrics. The MGCC Study Participants could not verify this, however, because the Energy Division did not provide price-related outputs (see Section 4.2.2).

The second method would rely on available CAISO market operational parameters and SERVM data. Values on a $ per MWh basis for three of the four reliability metrics are included in CAISO market optimization software parameters,[29] and a value for DR is available from SERVM modeling practices.

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28 MGCC Study Participants recognize that the import limits used in the SERVM model reflect existing import RA contracts. It is likely that that the CAISO market may import energy higher than RA contract levels, particularly when net loads in the rest of the Western Electricity Coordinating Council (WECC) are not extremely high. Ideally a robust WECC model would reflect resource plans of all LSEs and simulate market frictions to replicate WECC wide operation. In the absence of a robust WECC wide model of non-CAISO entities' resource plans, MGCC Study Participants offer a recommendation to use historical import levels correlated with WECC-wide LSE net loads to inform modeled maximum imports.

29 California ISO, Business Practice Manual for Market Operations (Version 79, Rev. Jan. 25, 2022), pp. 246-252. Available at: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Operations.

Under conditions of Grid Stress, the CAISO procures ancillary services (including reserves) up to a maximum price. Above that price cap (known as the penalty price), the CAISO prioritizes energy procurement over operational reserves. The CAISO has set the penalty price for ancillary services at $248-250 per MWh. (The three $1 price steps allow the model to have a "shortfall order" based on the sequence of the price caps for different ancillary service requirements.) Based on these practices, the two reserve metrics could each be valued at $250 per MWh.

The CAISO market rules allow energy procurement to occur at prices up to $2,000 per MWh ($2 per kWh).[30] When this price cap is reached, conditions of energy deficiency (Stage 2 Emergency) and load interruptions (Stage 3 Emergency) may occur. Based on this practice, EUE could be valued at $2,000 per MWh.

The SERVM inputs provided by the Energy Division state that the vast majority of DR resources are modeled as dispatched at a price of $600 per MWh. The remainder is dispatched at a price of $1,000 per MWh. Based on the SERVM input assumptions, and for simplicity, DR could be valued at $600 per MWh.

The reliability metrics could be weighted based on these practices to form a single Grid Stress metric, as shown in Table 4. Such a Grid Stress metric would be calculated on an hourly basis by multiplying the level of each reliability metric times the value-derived weighting factor. For example, if an hour has shortfalls of 100 MWh of Upward Reserve and 100 MWh of Non-Spin reserve, but no EUE or DR, then the Grid Stress metric would be 16.2 MWh (100 x 8.1% x 2). This hourly Grid Stress metric could be used to construct an equation relating a DA load metric, such as ANL_{T}, to the combined hourly capacity stress (grid stress) on the system.

Table 4: Potential Grid Stress Metric Weighting Factors

Reliability Metric	Value	Weighting Factor
Expected Unserved Energy (EUE)	$2,000 per MWh	64.5%
Demand Response (DR)	$600 per MWh	19.3%
Upward Reserve Shortfall	$250 per MWh	8.1%
Non-Spin Reserve Shortfall	$250 per MWh	8.1%

The MGCC Study Participants did not complete development of a final Grid Stress metric. Three steps would need to be taken to complete its development. First, the shortcomings in the SERVM forecast data discussed in Section 4.2.2 would need to be addressed. Second, any updates to the weighting factors would need to be considered, or potentially substituted with price-related model output data if made available. Third, the application of the Grid Stress metric in an MGCC pricing curve would need to be refined in order to balance the interest in more accurately reflecting grid stress with the importance of avoiding dramatic swings in revenue collection from year to year.

30 CAISO used a $1,000 MWh price cap through spring 2020, but per FERC Order 831 increased the price cap to $2,000 per MWh on June 13, 2021. https://www.caiso.com/Documents/Presentation-2021SummerReadinessUpdateCall-June23-2021.pdf.

Nonetheless, the MGCC Study Participants found that development and testing of the Grid Stress metric was informative regarding the relative contribution of the reliability metrics to overall grid stress. The general S-shape of the SERVM reliability metrics, which indicated that some forms of grid stress begin to increase at relatively low levels of net load, is reflected in the study's final recommended rate design in Section 6.2. This qualitative corroboration boosted the Participants' confidence in the research findings in Section 5. Furthermore, the MGCC Study Participants found the *annual* SERVM forecast data useful for assessing inter-annual variability, as discussed in Finding 5.7.3.

5 Research Findings

The MGCC Study Participants report the following findings based on their analysis of historical DA load forecasts and CAISO AWE events.

5.1 *Finding: DA Hourly Forecast Data Are More Useful Than 15- or 5-Minute RT Data for Design of a DAHRTP Rate.*

D.21-11-017 approved the use of CAISO's DA pricing and average Default Load Aggregation Point (DLAP) loss factor for the MEC component of the DAHRTP rate.[31] The MGCC Study Participants found that the MGCC component of the DAHRTP rate should also use the DA hourly load forecast data.

CAISO's energy market can be subdivided into three market products. CAISO produces a load forecast for both DA and day-of-market purposes. The vast majority of transactions take place in the DA markets while the day-of markets are used primarily to balance resources with actual loads. The CAISO's day-of-market pricing includes the Fifteen Minute Market and a five-minute market, or Real-Time Dispatch market. The day-of-market pricing products are not useful for a dynamic RTP rate design at this time. The final cost of energy procured through these two markets is often not known until later in the day, or perhaps further into the future, as CAISO must true-up actual energy deliveries. Perhaps more importantly, these products represent a relatively small minority of total energy consumption. The actual cost of energy to customers is best reflected by the DA market price.

Another important and practical reason to prefer DA pricing is that it can be supplied to participants in advance via a DAHRTP rate notification, allowing participants to optimize energy use or storage decisions for their business or home over the following day. For the same reasons, the CAISO DA hourly load forecast should be used for the design of a DAHRTP rate.

5.2 *Finding: A DAHRTP Rate Should Not Be Geographically Differentiated.*

For several reasons, a dynamic RTP rate is best offered across the entire PG&E system for generation costs only. In testimony, parties considered the potential for a geographically differentiated rate that takes into consideration varying conditions on PG&E's distribution system. However, there is evidence that it would be costly and confusing to customers to offer a geographically differentiated rate. Differentiating pricing based on distribution systems would require frequent updates, as pricing reflects the potential to defer additional investment. That potential may change as actual or forecasted customer load enters or exits the system, or when distribution investments are placed in service. Thus, incorporating area-based distribution rates would add substantial complexity to PG&E's information and billing systems, and could potentially confuse customers with accounts in multiple areas. Many of these same concerns would apply even if geographically differentiated rates were only used for

[31] D.21-11-017, pp. 9-10.

generation costs, which can differ within PG&E's DLAP.[32] Moreover, PG&E and all other LSEs within its service territory (such as Community Choice Aggregators) actually settle (or pay for) load at the DLAP, not the finer granularity used for generation resources.[33] Accordingly, PG&E's billing system does not track customers by sub-LAP. Indeed, there is relatively little differentiation in generation prices between sub-LAPs.[34]

It should be noted that, except for multiple RMO orders and a single Flex Alert issued by CAISO for Southern California, all of the AWEs in the historical record are at the CAISO level or apply to Northern California. Other than excluding Southern California AWEs from various analyses, the evaluation of generation reliability did not require differentiation between the PG&E system and other CAISO areas.

5.3 *FINDING: AWE Events Are a Good Indication of Generation-Related Grid Stress or Reliability Events.*

The CAISO calls AWE events when it anticipates grid stress or even the need to drop load. Generation-related events may be caused by high demand, supply shortfall (due to generator outages, fuel constraints, or low amounts of variable resource generation), and transmission constraints (congestion or outages). Based on CAISO's definitions and practice, the MGCC Study Participants found that the seven types of AWE events listed in Section 4.1.3 are a good indication of the potential for generation-related grid stress or reliability events.[35] Furthermore, the MGCC Study Participants found that AWE event hours are disproportionately represented in the highest 10% load hours.[36]

5.4 *FINDING: ANL_T is the Net Load Metric That Is Best Correlated With AWE Events.*

The MGCC Study Participants evaluated the six net load metrics described in Section 4.1.2 to determine which were most closely correlated with AWE events and determined that ANL_T performed best overall. By adjusting NL to account for non-CAISO system conditions using weather stations at PHX and SEA, ANL_T recognizes the relationship between extreme heat or cold and the lack of regional generating

32 The PG&E DLAP is a load-weighted average node (load source) that averages all the locational marginal price nodes within PG&E's service territory. The DLAP is the only point within PG&E's territory where power purchases are made, so all of PG&E's electricity purchases in CAISO markets occurs at PG&E DLAP prices.

33 For example, see https://www.caiso.com/InitiativeDocuments/SVPComments-ReviewTransmissionAccessChargeStructure-WorkingGroupMeetings-Aug29-Sep25_2017.pdf.

34 A.20-10-011, Exhibit PG&E-1, Ch. 2, pp. 2-12 to 2-15.

35 The MGCC Study Participants also evaluated Base Interruptible Program (BIP) events. Most of the non-local BIP events occurred in August and September 2020, and generally coincided with DA RMO, DA Flex Alert, Warning, and Stage 2 Emergency events. They found that the BIP events did not add significant value to the quantitative analyses but contribute to an understanding of the relationship between AWEs and DR dispatch.

36 For example, as measured using ANL_T, 87% of all AWE event hours (of any type) occur during hours with loads in the top 10th percentile and 72% occur during hours with loads in the top 5th percentile.

resources.[37] High temperatures often increase plant outages, while both high and extreme low temperatures increase load levels outside of the CAISO system. Extreme temperatures outside of the CAISO can therefore reduce the availability of imported power and exacerbate supply and demand imbalances on the CAISO system.

The MGCC Study Participants reviewed the frequency of all types of AWE events (RMOs, Flex Alerts, and W/Es) in various combinations as compared to the six candidate load metrics, considering both the full 2010-2021 period as well as a limited 2017-2021 period to focus on years with higher solar penetration. Based on many different combinations of AWE event types and different periods, the MGCC Study Participants concluded that the ANL_T is the net load metric that best balances alignment with AWE events and simplicity.

For example, there were 31 Alerts, Warnings or Emergency events[38] that indicated anticipated or actual grid stress from 2017-2021. Table 5 below shows the frequency (probability) of any such AWE event occurring on the system as the load metric increases. The columns represent the six different load metrics, while the rows represent the level of CAISO load expressed as a percentile over the entire dataset (2017-2021). Roughly one quarter of the recorded event hours occurred when loads were in the top 0.1% of all hours. Thus, a load metric that is a strong predictor of AWE events would show low probability of AWE events at low load levels and would increase to a high probability of an event at high load levels (in the top 0.1% of all hours). As shown in Table 5, ANL_T had the second highest frequency of such events (54.55%) during the top 0.1% of all hours, while ANL_{RT} (which also subtracts hydro and nuclear generation) had a slightly higher frequency of 56.82% in the highest 0.1% of hours.

Table 5: Alerts and Warning Event Frequency Compared to Candidate Load Metrics, 2017-2021,
Frequency of hours with any of the following: Alerts, Warnings, or Emergency (of any stage)

Percentile	GL	NL	ANL_R	ANL_T	ANL_{RT}	ANL_{RTG}
< 90 %	0.00%	0.01%	0.01%	0.00%	0.00%	0.00%
90 – 95 %	0.14%	0.18%	0.27%	0.14%	0.14%	0.23%
95 – 97 %	0.80%	0.91%	0.80%	1.03%	0.91%	0.34%
97 – 99 %	2.17%	2.05%	1.83%	1.48%	1.60%	2.05%
99 – 99.6 %	7.60%	5.70%	5.70%	6.46%	5.32%	5.32%
99.6 – 99.8 %	14.77%	12.50%	10.23%	4.55%	7.95%	11.36%
99.8 – 99.9 %	15.91%	20.45%	25.00%	31.82%	29.55%	29.55%
99.9 – 100 %	34.09%	38.64%	43.18%	54.55%	56.82%	50.00%

Depending on the particular AWE event types and time periods examined, other metrics such as ANL_{RT} or ANL_{RTG} may have slightly better performance than ANL_T. However, ANL_T also has two other advantages over other candidates. First, it is simpler to explain. Second, it has less inter-annual variability than metrics that include hydro generation. The MGCC Study Participants evaluated several approaches for hydro generation, but because they did not present any evident advantages over the

37 The best temperature coefficients for use in the ANL_T metric were determined using a logistic regression of the probability of RMO event hours. The logistic regression is described in Section 6.1.

38 In other words, AWE events excluding Flex Alerts and RMOs.

simpler formulation and would have required further analysis to reach agreement, the Participants agreed to exclude hydro generation from the recommended net load metric.

The MGCC Study Participants concluded that the ANL_T is the net load metric that is best associated with AWE events because under nearly all event types and time periods examined it had the highest or among the highest frequency of events at the high load percentiles, and because the other similar-performing metrics were more complex to calculate and explain to customers than ANL_T.

5.5 *FINDING: High Net Load Occurs From June To October and in Recent Years, Has Been Concentrated Between 3 PM and 10 PM.*

Using the ANL_T metric, high net load occurs from June to October, as illustrated in Figure 3.

Figure 3: Proportion of ANL_T in Top 1 Percentile by Month and Hour Ending, 2010-2021

	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Average
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	1%	4%	6%	7%	8%	9%	7%	2%	0%	0%	3%
7	0%	0%	1%	2%	5%	10%	12%	15%	17%	16%	10%	1%	0%	0%	6%
8	0%	0%	3%	5%	9%	16%	21%	22%	24%	21%	16%	3%	0%	0%	10%
9	0%	0%	0%	3%	7%	10%	11%	13%	13%	11%	5%	2%	0%	0%	5%
10	0%	0%	0%	1%	1%	1%	1%	2%	1%	1%	0%	0%	0%	0%	1%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Average		**0%**	**0%**	**1%**	**2%**	**3%**	**4%**	**5%**	**5%**	**5%**	**3%**	**1%**	**0%**	**0%**	

As illustrated in Figure 4, in recent years, high net load is concentrated between 3 PM and 10 PM.[39] The shift towards a later, more concentrated peak net load period is consistent with the impact of solar power development on the CAISO system.

39 All figures and charts depicting historical data show HE in Pacific Prevailing Time (i.e., including the influence of Daylight Saving Time). For example, HE 19 in June represents the time period of 6 PM to 7 PM, Pacific Daylight Time.

Figure 4: Proportion of ANL_T in Top 1 Percentile by Month and Hour Ending, 2017-2021

	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Average
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	3%	6%	8%	11%	13%	12%	4%	0%	0%	4%
7	0%	0%	0%	0%	1%	3%	5%	9%	17%	24%	15%	2%	0%	0%	6%
8	0%	0%	0%	0%	2%	9%	16%	22%	30%	34%	25%	8%	0%	0%	10%
9	0%	0%	0%	0%	2%	5%	6%	12%	18%	16%	10%	4%	0%	0%	5%
10	0%	0%	0%	0%	0%	0%	0%	2%	2%	1%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Average		**0%**	**0%**	**0%**	**0%**	**2%**	**3%**	**4%**	**7%**	**7%**	**5%**	**2%**	**0%**	**0%**	

It is also worth noting that the MGCC Study Participants observed similar patterns in the Grid Stress metric that was developed using SERVM forecast data. Although the MGCC Study Participants did not conclude analysis of hourly SERVM forecast data due to the shortcomings in the datasets discussed in Section 4.2.2, those shortcomings are unlikely to have substantial effects at a seasonal scale, or even when aggregating those data in a 12x24 format. The MGCC Study Participants can confirm that the same general patterns (June – October, afternoon/evening) are observed in the 2022 and 2026 SERVM forecast data.

5.6 *FINDING: High Net Load Contributes to, But Does Not Fully Explain, Grid Stress and Reliability Events.*

As noted in Finding 5.4, while AWE event hours are concentrated in the highest 5th or 10th percentile loads, there are still some AWE event hours that occur during lower load hours. Furthermore, even for hours with net load in the top 0.1% of all loads, no AWE event of any type (excluding RMOs) was called for roughly 20% of those hours. Both of these observations are unsurprising.

- Even when net load significantly exceeds the weather normal peak load forecast, the CPUC and the CAISO have directed LSEs to procure reserves, the level of which is planned to accommodate uncertainties such as unexpected resource outages.[40] When the level of outages is low, those resources can be expected to operate at nearly full capacity, and system distress does not develop despite very high loads.

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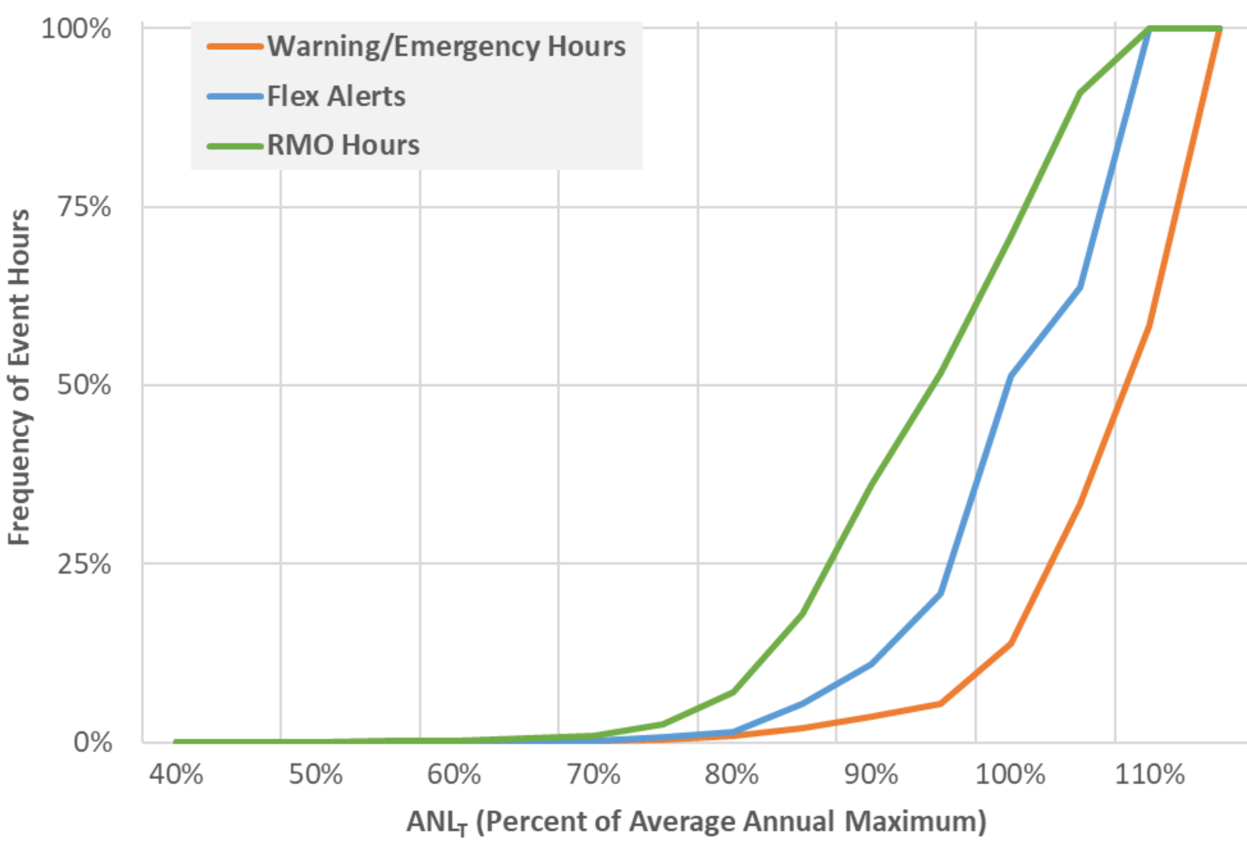
40 CPUC-jurisdictional load-serving entities must procure sufficient capacity to meet their expected 1-in-2 weather year peak load plus a 15% PRM according to current Resource Adequacy requirements. In D.21-03-056, the Commission temporarily increased the PRM to a minimum of 17.5% above expected peak demand for summer 2021 and 2022.

- Even when net load is significantly below the weather normal peak load forecast, other factors may contribute to system distress, such as reduced reserve levels caused by resource outages (loss of generator or transmission line) or resource limitations due to reduced availability of natural gas fuel caused by a polar vortex event or the Aliso Canyon gas storage incident.

The MGCC Study Participants determined that it is important to recognize the imperfect causal relationship between net load and grid stress and reliability events in the design of the MGCC component of the DAHRTP rate. Ideally, that rate will provide a price signal to DAHRTP participants that is highest when both the probability and severity of a generation reliability constraint are highest. Similarly, if either the probability or the significance of a generation reliability constraint is very low, then the MGCC component price should also be low.

While later findings will describe in more detail the relationship between net load and reliability, this finding demonstrates that on a meaningful number of days with high net load hours, the CAISO does not perceive any grid stress or reliability concerns. However, as shown in Figure 5, the probability of each of the three categories of AWE events increases with adjusted net load.

Figure 5: AWE Hour Frequency, Relationship to Peak Adjusted Net Load (ANL_T), 2010-2021[41]



41 The x-axis scale goes above 100% because some years (in particular, 2020) had significantly higher maximum loads than the average, which was calculated based on 2010 through 2021.

A more in-depth look at the relationship between AWE events and net load helps illustrate the effect of other factors on grid stress and reliability events. Figure 6 shows heat maps for DA RMO and Flex Alert events, EDO Flex Alerts, and W/E events for hours with peak loads *above* the 99^{th} percentile, and Figure 7 shows the same heat maps for hours with peak loads *below* the 99^{th} percentile.

AWE event hours in Figure 6 show an unsurprising and consistent pattern for higher loads. For lower loads (Figure 7), especially during the earlier pre-2017 (low solar) years, AWE events sometimes occurred outside the June-October period, and sometimes relatively early in the day. The EDO Flex Alerts are a potentially strong indication of events that could not be anticipated by a DA net load signal alone.

Figure 6: Number of AWE Event Hours by Month and Hour Ending with ANL_T Above 99^{th} Percentile

DA RMO

2010-2016 (low solar)

	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	3	4	4	4	4	4	-	-	-
7	-	-	2	2	2	5	5	5	5	5	5	1	-	-
8	-	-	2	3	3	4	6	6	6	5	4	-	-	-
9	-	-	-	-	1	2	2	2	2	2	-	-	-	-
10	-	-	-	1	1	1	1	1	1	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-

2017-2021 (high solar)

	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	1	4	5	7	8	8	3	-	-
7	-	-	-	-	1	2	4	4	7	7	5	2	-	-
8	-	-	-	-	2	9	14	17	20	20	20	9	-	-
9	-	-	-	-	2	4	5	7	10	10	7	4	-	-
10	-	-	-	-	-	-	-	1	1	1	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-

DA Flex Alert

2010-2016 (low solar)

	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	1	1	1	2	2	2	2	1	1	-	-	-
8	-	-	2	2	2	2	2	2	-	-	-	-	-	-
9	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-

2017-2021 (high solar)

	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	1	2	2	2	1	-	-
7	-	-	-	-	-	-	-	-	2	2	1	-	-	-
8	-	-	-	-	-	5	5	5	5	5	5	5	-	-
9	-	-	-	-	1	2	3	5	6	6	5	1	-	-
10	-	-	-	-	-	-	-	1	1	1	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-

EDO Flex Alert

2010-2016 (low solar)

	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	1	1	1	1	1	1	-	-	-
7	-	-	1	1	1	1	1	1	1	-	-	-	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	-	-	-	1	1	1	1	1	1	1	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-

2017-2021 (high solar)

	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	1	1	1	1	-	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Warning or Stage 1,2,3 Emergency

2010-2016 (low solar)

	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	1	1	1	1	1	1	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	-	-	-	1	1	1	1	1	1	1	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-

2017-2021 (high solar)

	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	1	1	-	-	-
7	-	-	-	-	-	-	-	-	2	3	3	-	-	-
8	-	-	-	-	2	5	5	5	5	5	4	3	-	-
9	-	-	-	-	-	-	1	1	2	2	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Figure 7: Number of AWE Event Hours by Month and Hour Ending with ANL_T Below 99th Percentile[42]

DA RMO

2010-2016 (low solar)

	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	2	2	2	1	1	1	1	1	1	1	1	1	1	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	4	4	4	4	4	1	-	-	-	-	-	4	3	-
7	6	6	4	4	4	1	1	1	1	1	1	5	4	-
8	6	6	4	3	3	2	-	-	-	1	1	5	-	-
9	2	2	2	2	1	-	-	-	-	-	2	2	1	-
10	1	1	1	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-

2017-2021 (high solar)

	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	1	1	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	4	4	8	8	8	7	4	3	1	-	-	5	3	-
7	6	6	8	8	7	6	5	5	2	2	4	4	1	-
8	19	19	23	23	21	14	9	6	3	3	2	13	10	-
9	7	7	10	10	8	6	5	3	-	-	3	3	5	-
10	3	3	3	3	3	3	3	2	2	2	3	3	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-

DA Flex Alert

2010-2016 (low solar)

	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	1	-	-	-	-	-	-	-	-	-
8	-	1	-	-	-	-	-	-	-	-	-	-	-	-
9	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-

2017-2021 (high solar)

	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	3	3	1	1	2	-	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	-	-	-	1	-	2	3	1	-	-	1	-	-	-
10	-	-	-	-	-	2	2	1	1	1	2	2	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-

EDO Flex Alert

2010-2016 (low solar)

	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	1	1	1	1	1	1	1	1	1	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	1	1	1	1	1	1	1	1	1	1	1	1	1	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	1	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	-	-	1	-	-	-	-	-	-	-	1	1	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-

2017-2021 (high solar)

	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Warning or Stage 1,2,3 Emergency

2010-2016 (low solar)

	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	1	1	1	1	1	1	1	1	1	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	1	1	1	1	1	-	-	-	-	-	-	1	1	-
7	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	-	-	1	-	-	-	-	-	-	-	1	1	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-

2017-2021 (high solar)

	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	1	1	1	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	2	2	1	1	2	1	-
8	-	-	5	5	3	-	-	-	-	-	-	-	3	-
9	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-

42 Note that some DA RMO hours occurred earlier than the hours shown in this figure. The figure is constrained to HE 11 – 24 to focus on features of interest.

5.7 *FINDING: A Reasonable Standard for Inter-Annual Variability Is a Coefficient of Variation (CV) of up to 0.4.*

Some inter-annual variability in generation cost recovery from a DAHRTP rate is inevitable, and perhaps even desirable—higher rates in years with more grid stress are reasonably balanced with lower rates in years with less grid stress. The MGCC Study scope directs this report to consider "what level of intra- and inter-annual variation is most appropriate and would most accurately capture varying levels of capacity shortfall risk within a year and across multiple years."[43]

To put the variability of generation revenue recovery for the RTP rate into perspective, the MGCC Study Participants determined how much inter-annual variability occurs in actual generation energy and capacity costs from year to year. While there is no directly comparable measure of the annual cost to procure long-term capacity requirements, three types of capacity-related benchmarks provide an indication of the level of variation that might be reasonable to accept for an MGCC pricing formula, as follows.

- **Historical record** – Variation in load, net load, and energy prices
- **Resource adequacy** – Variation in weighted average RA prices
- **SERVM Grid stress metrics** – Variation in EUE, DR and reserve shortfalls

For each metric included in the three benchmark evaluations, a CV is calculated to indicate inter-annual variability relative to the average value, generally calculated as the standard deviation divided by average.

Overall, the three benchmarks showed that the CV of capacity-related benchmarks occurs in a range of 0.25 to 0.7. For two classes of benchmarks, the maximum CV is 0.4. For that reason, the MGCC Study Participants found this analysis suggests that reasonable standard for inter-annual variability is a CV of up to 0.4.

5.7.1 FINDING: Based on historical load and pricing data, a reasonable level of inter-annual variability is a CV of 0.25 – 0.40.

The historical record for load, net load and energy prices is perhaps the simplest source of comparison data on interannual variability. While future and historical loads will not be exactly comparable due to the increased buildout of solar generation, some trends are likely to remain robust despite changes in the generation mix. Six metrics are presented, all of which reflect annual averages except "Days ANL_T > 32,000" (number of days in which ANL_T exceeded a threshold of 32,000 MW). As shown in Table 6, the CV is only 5-10% for the three load-related metrics. For the other three metrics, the CV ranges from 20-39%.

43 MGCC Stipulation, pp. 5-6.

Table 6: Annual Average CAISO Loads and PG&E DLAP DA Prices, 2011-2021

Year	Gross Load	Net Load	Max Daily ANL_T	Days ANL_T > 32,000 MW	DA Price	Max Daily DA Price
2011	26,252	25,291	21,275	6	31.20	51.58
2012	26,770	25,472	24,731	29	29.25	45.19
2013	27,309	25,235	24,427	20	42.18	56.78
2014	27,002	24,220	24,562	18	48.94	68.62
2015	26,940	23,758	24,337	24	34.07	51.23
2016	26,699	22,764	22,861	15	29.86	50.03
2017	26,457	21,971	22,685	20	34.56	76.23
2018	25,928	20,868	22,281	16	39.48	79.85
2019	25,252	20,168	21,785	11	37.12	72.20
2020	25,067	19,856	23,089	35	33.42	78.77
2021	25,703	19,111	23,783	26	53.95	103.99
CV	**0.03**	**0.10**	**0.05**	**0.39**	**0.20**	**0.25**

The MGCC Study Participants make several observations regarding these data:

- None of these metrics are equivalent to the annual contribution towards the price of providing long-term capacity resources, but each has its own relevance.
- While GL shows a relatively flat trend, NL trends down, mainly due to expanding renewable generation reducing the NL each year. This downward trend explains the higher CV of NL as compared to GL.
- Despite annual average NL decreasing each year, neither of the ANL_T metrics shows a downward trend.
- Price-related metrics have a somewhat higher inter-annual variability as measured by CV.
- The number of days with very high ANL_T has the highest CV of all the metrics displayed here.

Because capacity costs are driven by extreme events, MGCC Study Participants consider that based on the historical data presented above, a reasonable level of inter-annual variability in the collection of MGCC costs as measured by CV should fall in the upper range of the metrics displayed in Table 6, i.e., 0.25 – 0.40.

5.7.2 FINDING: Based on Resource Adequacy Price Variability, a Reasonable Level of Inter-Annual Variability is a CV of 0.3 to 0.4.

Resource adequacy market prices provide another source of capacity-related historical costs data. However, in comparison to the historical data in Finding 5.7.1, the resource adequacy market represents volatility in prices to meet future, short-term capacity requirements.

The MGCC Study Participants have examined 2012-2021 resource adequacy (RA) market prices from the Energy Division's annual RA Reports.[44] The analysis used the CAISO System Resource Adequacy (System RA) weighted average contract prices ($/kW-month), with all prices converted to real dollars ($2021) using a 2% annual generation inflation rate. Since the 2021 RA report is not yet available, the analysis imputes a 2021 System RA value of $6.88/kW-month using the 2020 RA report price and the difference between the 2020 and 2021 Market Price Benchmark (MPB) System RA Adder from the Energy Division's annual Power Charge Indifference Adjustment (PCIA) MPB True-Up and Forecast filings.[45] The MGCC Study Participants decided to include an imputed 2021 capacity price for consistency with other analyses in this report, and because it is important to consider the 2021 conditions which resulted in a tightening of the capacity market, and a considerable increase in capacity prices and overall price variability.

As shown in Table 7, the CV for System RA market price variability during 2012-2021 is 0.37. Due to the use of an imputed 2021 System RA value, the MGCC Study Participants interpret this result as supporting inter-annual variability with a CV of 0.3 to 0.4.

Table 7: System Resource Adequacy Price Variability

Year	Monthly System RA Price
2012	3.47
2013	3.35
2014	(missing)
2015	2.76
2016	2.69
2017	2.26
2018	2.93
2019	3.60
2020	4.85
2021	6.88
Average	***5.25***
CV	**0.37**

5.7.3 FINDING: SERVM Model Outputs Show Inter-Annual Variability With a CV of 0.3 to 0.7.

While MGCC Study Participants did not use hourly SERVM forecast data for rate design purposes, *annual* SERVM forecast data do provide another useful benchmark for inter-annual variability of reliability metrics. The limitations on use of hourly reliability metrics discussed in Section 4.2.2 are less impactful when considering annual aggregations or averages of the data.

44 See https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage.

45 The difference between the 2020 and 2021 System RA MPB is $2.13/kW-month. The analysis adds this $2.13/kW-month to the 2020 price from the RA report ($4.75/kW-month) to yield an imputed 2021 System RA price of $6.88/kW-month. This value is close to the unadjusted 2021 System RA MPB of $7.33/kW-month from the 2021 PCIA MPB True-Up and Forecast filing.

As discussed in Section 4.2.3, the MGCC Study Participants identified four reliability metrics that could comprise a potential Grid Stress Metric, including EUE, DR, Upward Reserve Shortfall, and Non-Spin Reserve Shortfall. However, the data required to calculate Upward Reserve Shortfall are not included in the annual aggregation of SERVM forecast data. Thus, for this analysis, only three reliability metrics are used to provide an indication of CV values for grid stress using selected cases from the SERVM forecast data for 2022 and 2026.[46]

The SERVM case data for 2022 and 2026 in Table 8 shows that the CV for the three reliability metrics can vary from 0.27 to 2.63. These findings are based on a simplified 20-case dataset for each forecast year, with each case reflecting a different "weather year" of load.

Table 8: Reliability Metrics in 2022 and 2026 SERVM Forecast Data

	Demand Response	Non-Spin Reserve Shortfall	EUE
2022 Forecast (20 low-load cases)			
Annual Average (MWh)	*8,450*	*29,590*	*81*
CV	**0.27**	**0.45**	**1.76**
2026 Forecast (20 mid-load cases)			
Annual Average (MWh)	2,038	4,726	116
CV	**0.70**	**0.63**	**2.63**

As expected, the most severe form of grid stress (EUE, representing Stage 3 emergencies or rolling outages) shows the smallest average MWh per year and the greatest volatility—many of the 20 cases in each forecast had no EUE. Grid stress represented by DR and Non-Spin Reserves were much more frequent and had greater average annual MWh, while showing less variation year-to-year. However, even for these milder forms of grid stress, SERVM modeling indicates that coefficients of variation in the range of 0.3 to 0.7 occur.

The CV for the three reliability metrics shown in Table 8 may not represent the full variability of annual costs, since each of the 20 cases selected in each run represents an average over 50 iterations, as explained in Section 4.2.1. SERVM runs creates random generator and transmission outages within each of 50 SERVM iterations; averaging over those iterations removes the variability among the 50 iterations. Nonetheless, the remaining variability among the cases provides a useful measure of potential inter-annual variability that is focused on the generation resources and loads that the Commission's Energy Division anticipates will be in place for 2022 and 2026.

46 The full 100-case dataset was not used because each dataset includes five 20-case runs with varying customer load forecast levels – variation in reliability metrics across these varying levels would measure load variability, not inter-annual variability. Since the 2022 dataset provided by the Energy Division is a high-load scenario, the low-load cases for the 2022 dataset were selected for comparison. For the 2026 dataset, the mid-load cases were selected.

5.8 *Finding: Flex Alerts Provide the Best DA Indication of Grid Stress Conditions That Are Not Well Captured by a Net Load Metric.*

The MGCC Study Participants determined that a price signal triggered by *actual* DA Flex Alert is the best indicator of grid stress conditions that are not well captured by the ANL_T metric. Other candidates for the non-ANL_T indicators of grid stress included DA RMO and Alerts. Along with Flex Alert events, these are the only CAISO events that are consistently called on a DA basis.

Flex Alerts already have significant public exposure, so relying on those events will enhance RTP customer engagement with the program on precisely the days when that engagement is most useful. Furthermore, D.21-12-015 explicitly links the Residential ELRP to the Flex Alerts paid media campaign, increasing the relevance of Flex Alerts to load control. While D.21-12-015 also authorizes the CAISO to trigger the ELRP with Alerts, there is no paid media campaign associated with Alerts—and in recent years, the CAISO has issued Alerts and Flex Alerts nearly contemporaneously.

The MGCC Study Participants also considered using RMO events to trigger a DA price signal. One advantage of using RMO events is that RMO events would add relatively less inter-annual variability than Flex Alerts (see Table 10 in Section 6.1.4). However, relying on RMO events for an event-triggered price signal raises the following concerns.

- While RMOs do indicate grid stress conditions, they reflect generation rather than load. In contrast, Flex Alerts are demand-oriented events that the CAISO calls when it wants customers to reduce consumption to reduce the probability of demand outstripping supply.
- Almost no customers are familiar with RMOs or understand how they should apply to their behavior or operations.
- The RMO signal would need to be restricted to peak and near-peak hours as described in Section 4.1.3, further adding to potential customer confusion.

It should also be noted that this finding refers to use of the *actual* DA Flex Alerts for triggering an adder in the MGCC pricing formula. For purposes of analysis using historical data, the MGCC Study Participants used the combined FA/A data in almost every instance, as explained in Section 4.1.3.

5.9 *Summary: Conceptual Model of Grid Stress and Reliability Events*

Taking into consideration the findings above, the MGCC Study Participants formulated the following simple conceptual model of grid stress and reliability events.

- Low ANL_T days have a low, but non-zero, probability of AWEs, because, as discussed previously, other factors affect system reliability. On these days, a net load measure is a poor predictor of grid stress and reliability.
- High ANL_T days have a high probability of AWEs, but not a 100% probability. Other factors affect system reliability. Furthermore, peak ANL_T levels vary from year to year due to variations in weather, economic conditions, and resource development.

This conceptual model supports using a formula that calculates much of the DAHRTP price from the value of ANL_T, with the remainder captured by a Flex Alert "adder."

6 Development of the Recommended MGCC Pricing Formula

The MGCC component of the DAHRTP rate formula will allocate MGCC marginal cost revenues to the various hours in the year. For most hours of the year, it is reasonable that the MGCC value would be zero or virtually zero because the intent is to allocate the MGCC component to those relatively small number of hours in which grid stress and reliability impacts occur, affecting the marginal generation capacity requirement.

Reflecting the conceptual model in Section 5.9, the MGCC Study Participants conducted further research to design the functional form of the equation depending on ANL_T and Flex Alert events, as shown in Equation 2. The largest portion of MGCC costs should be recovered through a function that depends on ANL_T, whose maximum value is expected to be 100%, based on a logistical regression of RMO events as described below in Section 6.1. The remaining MGCC costs should be recovered through a binary variable (value of 0 or 1) representing whether or not the CAISO calls a DA Flex Alert. The hourly price is determined using the variables H (hourly) and E (event), which are optimized to recover the total MGCC in an average year.

Equation 2: Conceptual Hourly MGCC Pricing Formula

$$\text{Hourly MGCC Price} = H * f(ANL_T) + E * \text{Flex Alert}$$

In Finding 5.4, the MGCC Study Participants found that ANL_T best captures grid stress and reliability impacts on an hourly basis during hours with a high probability of such impacts. In Finding 5.7, the Participants found that Flex Alerts provide the best DA indication of grid stress conditions that are not well captured by the ANL_T metric. Thus, when the likelihood of grid impacts is relatively low, an allocation based on a combination of ANL_T (as shown in Figure 5) and a Flex Alert event adder will result in a low MGCC price. However, if the CAISO has declared a DA Flex Alert event based on an expectation of grid stress or reliability issues, then even if forecast ANL_T is low, there should be a significant MGCC price component. At higher net loads, the ANL_T-based capacity price component will be more significant even when the CAISO has not called a Flex Alert event. A combination of a high ANL_T and a Flex Alert event declaration will result in the highest capacity price.

The development and explanation for the recommended price formula is set forth in the following sections.

6.1 Probability of AWEs by Load Level Using a Logistic Regression Analysis

To develop the function $f(ANL_T)$, the MGCC Study Participants recognized that the relationship between the probability of AWE events and ANL_T, as shown in Figure 5, shows classic sigmoidal (S-curve) shapes, with accelerating probabilities at low net load and flattening probabilities at extremely high net load. To model the probability of each type of AWE event occurring as a function of ANL_T, the MGCC Study Participants used a logistic regression method to generate a sigmoidal curve that most closely represents historical data. The results of the logistic regressions are sigmoidal versions of the PCAF function (PCAF-S). A suitable formula for the fitted probability function is a logistic function, where A and B are adjustable coefficients, with B always positive, as shown in Equation 3.

Equation 3: PCAF-S Logistic Probability Function

$$\text{PCAF-S}(ANL_T) = 1 / (1 + \exp(A - B^* ANL_T))$$
$$\text{PCAF-S}(ANL_T < L) = 0$$

At low ANL_T the function looks like a quadratic curve, while at high ANL_T it approaches 1. The function is set to zero when the ANL_T is lower than the 90th percentile (L, or limit) to avoid applying (extremely small) capacity costs at low or moderate net loads.[47]

In the logistic regression, ANL_T is normalized to range from 0 to 1. The coefficients A and B are chosen to minimize a "loss function" which penalizes both false positives (when the probability curve is greater than zero and there was no AWE), and also false negatives (when the probability curve is less than one and there was an AWE), as shown in Equation 4.

Equation 4: Loss Function for Logistic Regression

$$Loss\ Function\ = -\sum_{i=1}^{N} y_i * \log\left(p(y_i)\right) + (1 - y_i) * \log\left(1 - p(y_i)\right)$$

Here y_i is a binary variable which is 1 if there was an AWE in hour i and zero otherwise, and $p(y_i)$ is the modeled probability at hour i using the formula above and the adjusted net load in hour i.

6.1.1 Fitting the PCAF-S Logistic Probability Function

The PCAF-S logistic function was fitted to each of the three types of AWEs—in order of decreasing severity, W/E, FA/A and RMOs.[48] The fitting considered only the most recent five years of available data (2017-2021), rather than the 2012-2021 dataset used in Figure 5, for the following three reasons.

1. Prior to 2017, as solar generation was increasing rapidly, the timing of the net peak was shifting later in the day. While solar generation continued to increase through 2021, the timing of the net peak and associated reliability impacts have stabilized both because the pace of utility-scale solar installations slowed after 2017 and because the shift is constrained by when the sun sets.
2. Climate change is continuing to accelerate, which affects load variability, occurrence of extreme weather conditions such as heat waves, and wildfires (which in turn can affect transmission and generation availability). Earlier years correspond to somewhat different climate conditions than more recent periods.

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47 The 90th percentile net load occurs at approximately 60% of the average annual maximum, which is well below PG&E's original proposed PCAF threshold of 80% of average annual maximum load. A.20-10-011, Exhibit PG&E-1, Ch. 2, p. 2-3.

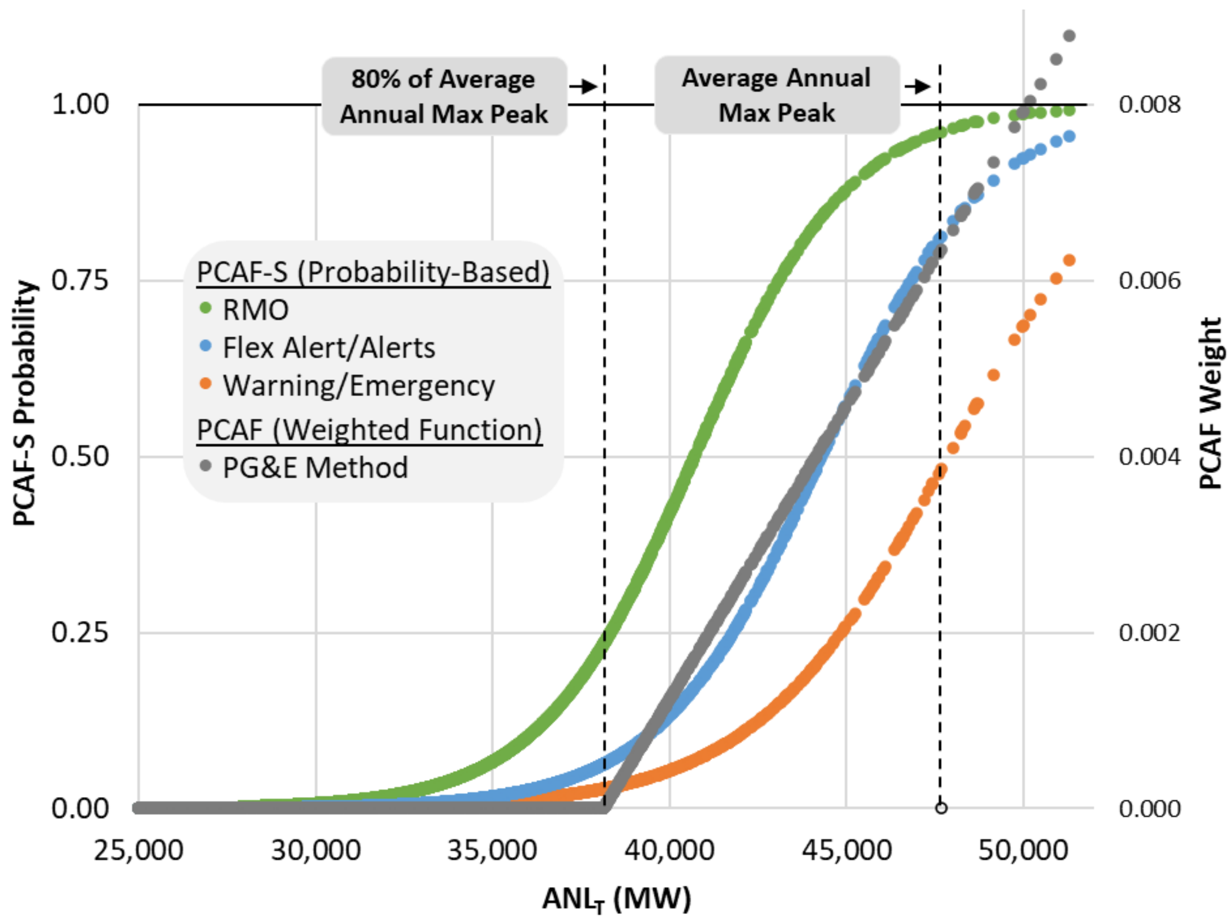
48 As explained in Section 4.1.3, the RMO data were limited to the hours of 3 PM to 10 PM, corresponding to the vast majority of hours covered by W/E and DA FA/A events.

3. The CAISO has indicated that it frequently updates its proprietary procedures for calling AWEs, so the earlier AWEs called prior to 2017 may have been based on materially different criteria than those in use today.

Furthermore, the MGCC Study Participants confirmed that this decision was reasonable by comparing the logistic regressions using the more recent data (2017-2021) with similar analysis of the full dataset (2010-2021). Use of the more recent data (2017-2021) resulted in logistic regressions with better fits to actual AWEs (i.e., smaller loss functions).

The logistic regressions for the three alternative PCAF-S functions yielded the probability-based curves shown in Figure 8. For comparison purposes, the original PCAF method proposed by PG&E (which weights MGCC costs beginning at 80% of the average of annual maximums of ANL_T) is shown—but using a different y-axis on the right since PCAF weights are deterministic allocation factors rather than probabilities and increase without limit as the adjusted net load increases.

Figure 8: Alternative Functions $f(ANL_T)$ for MGCC Pricing Formula,
Applied to Net Load for 2017-2021



6.1.2 Measuring the Performance of Logistic Regression Models

Given the desired alignment of the MGCC hourly allocation with the CAISO's operational grid stress events, the MGCC Study Participants recognized a need for a means to check the effectiveness of the model in distinguishing between events (AWE=1) and non-events (AWE=0). The MGCC Study

Participants chose a widely used performance metric[49] called the "Kolmogorov-Smirnov" (KS) statistic[50] which measures the maximum difference between the distribution of cumulative events and cumulative non-events and ranges between 0% and 100%.[51] The higher the KS Statistic, the better the discriminatory power of the model.

Using the ANL_T as the only independent variable in the logistic regression to predict RMO events gives a KS Statistic of 92% suggesting a strong ability of this model to distinguish between RMO events and non-events.

6.1.3 Allocation of MGCC by ANL_T for Alternative PCAF-S Functions

The total MGCC could be allocated on an hourly basis using any of the ANL_T functions shown in Figure 8, or even a combination of them. The choice of the function impacts both the maximum capacity cost and the expected inter-annual variability likely to be realized during the pilot.

To illustrate how the functions differ in driving the maximum capacity cost, Figure 9 shows the same four curves as in Figure 8 but scaled so that the total capacity cost over the period 2017-2021 is the same for each curve. Each curve is normalized so that the average annual MGCC (2017-2021) equals the annualized value of $90.35, as decided in D.21-11-016 (see Section 3). MECs (DA prices at PG&E DLAP plus primary voltage losses of 1.9%) are also illustrated in the red dots for comparison. The total generation rate is the sum of the MEC, MGCC, and RNA (not shown) in a given hour.

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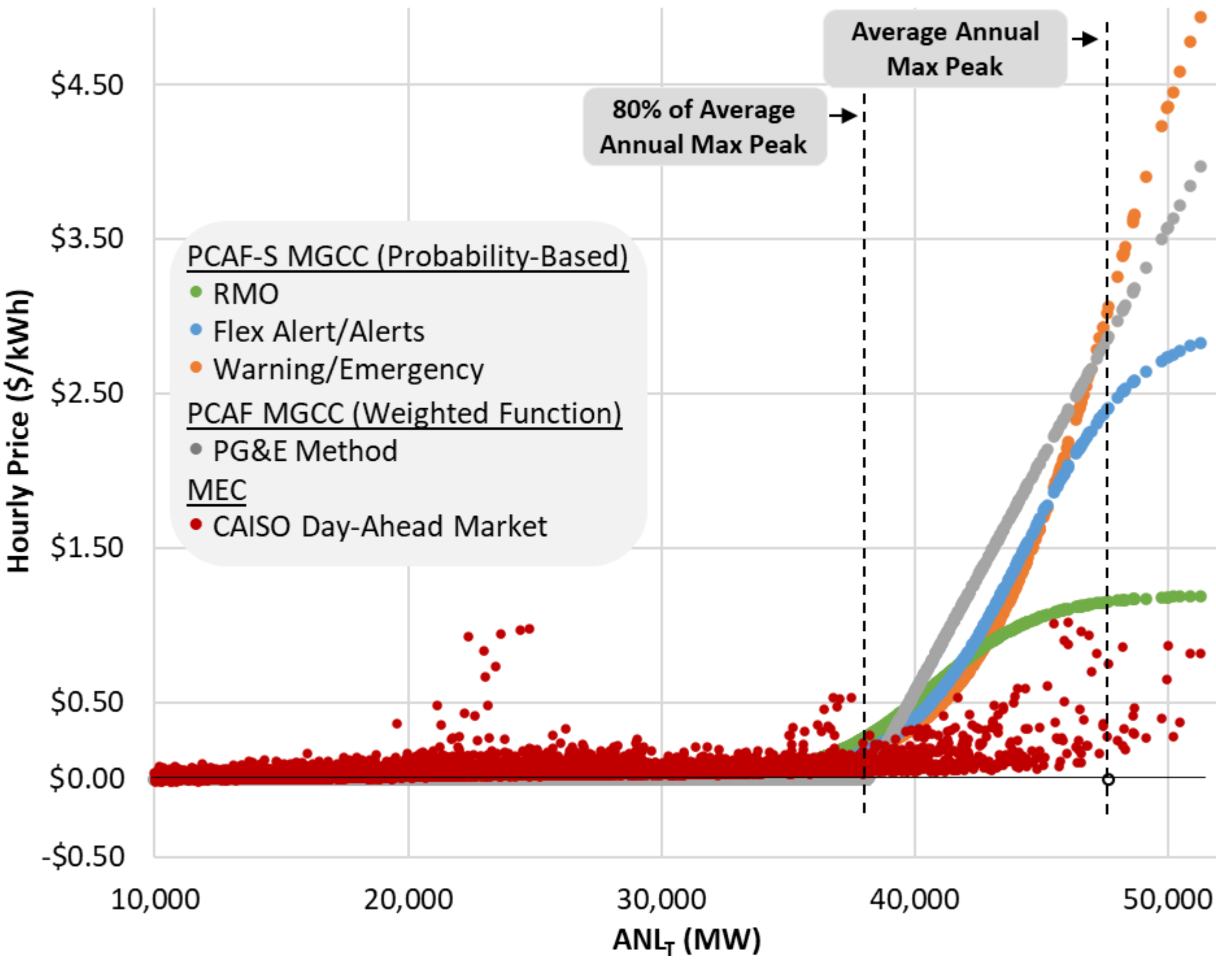
49 For example, the KS Statistic is used in credit risk modeling. Federal Reserve Board, "The Kolmogorov-Smirnov and Divergence Statistics," Report to the Congress on Credit Scoring and Its Effects on the Availability and Affordability of Credit, https://www.federalreserve.gov/boarddocs/rptcongress/creditscore/general.htm.

50 Kolmogorov-Smirnov Goodness of Fit Test, National Institute of Standards and Technology, https://itl.nist.gov/div898/software/dataplot/refman1/auxillar/kstest.htm.

51 Using the logistic regression model, each hourly record is scored with a probability of event (AWE). The KS Statistic is then calculated as follows:

1. The complete dataset is arranged in decreasing order of predicted event probability and then divided into a finite number of groups, e.g. 20 groups.
2. For each group, the cumulative percent of events and non-events is calculated along with the difference between these two cumulative percentages.
3. The KS Statistic is the maximum difference between the cumulative percent of events and non-events.

Figure 9: MGCC Pricing Formula Alternatives, with MEC Prices (for comparison),
Applied to Net Load and CAISO Day-Ahead Energy Prices for 2017-2021



The MGCC Study Participants note the following observations in response to Figure 9.

- MECs never got above $1.00/kWh, or $1000/MWh, because CAISO DA prices were capped at $1000/MWh during this period. Going forward, CAISO will allow DA energy prices to reach $2000/MWh under certain circumstances.
- The high MECs at ANL$_T$ between 20,000 MW and 25,000 MW all correspond to the February 2021 Texas freeze, which caused natural gas prices paid by electric generators in the CAISO market to escalate dramatically. While there were no capacity issues in California during that event, the very high natural gas prices caused very high wholesale electricity prices (still well below the cap of $9000/MWh in place in Texas at that time).
- The density of points (per MW on the x-axis) is much less at very high ANL$_T$, as indicated by the gaps (dotted portion) in the four curves. There were only five hours during 2017-2021 in which the ANL$_T$ was at or above 50,000 MW (all in 2020).
- The "area under the curve" looks like it is lowest for the RMO PCAF-S function (green) and greatest for the W/E PCAF-S function (orange). However, the density of load points is much

greater at low to moderate ANL_T, so there are many more hours being assigned capacity costs at the lower portion of the RMO PCAF-S function than at the higher portion of the W/E PCAF-S function. Even though the "area under the curve" looks lowest for the RMO PCAF-S, the four MGCC pricing formula alternatives are identically scaled to result in the same annualized capacity price signal ($/kW-yr). Each alternative distributes the MGCC cost differently among hours—both within and between years.

- Since the RMO PCAF-S function has the greatest probability at low to moderate ANL_T (where most of the points are, as shown in Figure 8), its maximum price is the lowest (slightly above $1.00/kWh, as shown in Figure 9). (Again, the total MGCC is the same for each of the four alternatives.) The PCAF method function takes effect at the highest ANL_T value and has the second-highest maximum price of approximately $4/kWh (as shown in Figure 9).[52] The W/E PCAF-S function actually has some weight below the PCAF threshold, but for most of its range it has the lowest weight. Then, at the highest levels of ANL_T, the maximum price for the W/E PCAF-S function reaches approximately $5/kWh (as shown in Figure 9). Overall, the W/E PCAF-S function has the highest maximum price of the three probability-based alternatives. The FA/A PCAF-S function is in the middle.
- Because almost all extremely-high ANL_T hours corresponded to an actual RMO event, the RMO PCAF-S function in Figure 8 reaches almost 1 within the scale of the figure, and likewise its corresponding MGCC pricing in Figure 8 flattens out at the highest ANL_T values observed in 2017-2021. While the FA/A PCAF-S function is visibly flattening at those levels, it is not as close to its maximum.
- In contrast, the W/E PCAF-S function is only getting slightly less steep at the highest ANL_T, and could increase toward its maximum of approximately $6.40/kWh if higher ANL_T were to occur. Similarly, the PCAF curve would continue to increase without limit at ANL_T above the 2017-2021 historical maximum. Such high price levels, coupled with these two functions' lower prices at lower load levels (compared to the RMO function), dramatically increase the inter-annual volatility of capacity-related revenue collection (see Section 6.1.4).

If a combined alternative were selected, applying more weight to the W/E PCAF-S or PCAF functions would risk more extreme capacity costs at high ANL_T, and would diminish the price signal at lower ANL_T. As discussed in the following section, this turns out to have implications for inter-annual revenue variability.

6.1.4 Inter-Annual Revenue Variability for Alternative PCAF-S Functions and Flex Alert Pricing

To get a sense for the inter-annual revenue variability associated with potential elements in the MGCC function, the annual capacity cost for a flat load (i.e., not considering load shape) was calculated for each of the three alternative PCAF-S functions described above. The same calculations were performed for the original PCAF function from PG&E's testimony and a hypothetical Flex Alert event-only MGCC

52 Note that the PCAF threshold was calculated using only the maximum annual net loads from 2017-2021; using 2014-2021 or 2012-2021 maximum annual net loads the PCAF threshold would have been lower, and the maximum PCAF price would also have been lower.

price.[53] Each of the MGCC elements was scaled so that the annual MGCC over 2017-2021 averaged $90.35/kW-yr.

The MGCC-only results for each alternative PCAF-S function, the original PCAF function, and as the Flex Alert are shown in Table 9. Table 10 shows the same statistics for total generation cost (MEC plus MGCC). For comparison between these and other measures of inter-annual variability, the CV is calculated as the standard deviation divided by average, as discussed in Finding 5.7.

Table 9: Annual Total Capacity Cost for Candidate MGCC Rate Elements, 2017-2021 ($/kW-year)

Year	**PCAF** PG&E Method	**PCAF-S Alternatives** Probability-Based			**Event Adders**	
		W/E	**Flex**	**RMO**	**Flex**	**RMO**
2017	$ 141.05	$ 131.73	$ 134.62	$ 128.70	$ 90.35	$ 131.42
2018	77.55	77.40	80.95	84.82	23.32	41.07
2019	26.56	35.81	38.90	53.11	17.49	16.43
2020	169.59	163.26	150.42	125.39	209.85	139.63
2021	37.00	43.55	46.86	59.72	110.75	123.20
Average	90.35	90.35	90.35	90.35	90.35	90.35
Annual Max/Min Ratio[a]	*6.39*	*4.56*	*3.87*	*2.42*	*12.00*	*8.50*
CV	*0.62*	*0.55*	*0.50*	*0.35*	*0.77*	*0.57*

(a) The annual max/min ratio is the ratio of the maximum and minimum values for 2017-2021.

53 As discussed in Finding 5.8, the MGCC Study Participants also considered using RMO events to trigger a day-ahead price signal. As shown in Table 10, an advantage an RMO event trigger is relatively less inter-annual variability than a Flex Alert event trigger. For reasons explained in Finding 5.8, the Participants determined that a Flex Alert event trigger provides the best day-ahead indication of grid stress conditions that are not well captured by a net load metric.

Table 10: Annual Total Generation Cost for MGCC Rate Elements, 2017-2021
Including MECs and MGCCs (from Table 9), Applied to Net Load and CAISO Day-Ahead Energy Prices

Year	MEC CAISO Market	Total Generation Cost = MEC + MGCC					
		PCAF PG&E Method	PCAF-S Alternatives Probability-Based			Event Adders	
			W/E	Flex	RMO	Flex	RMO
2017	$ 308.46	$ 449.51	$ 440.19	$ 443.08	$ 437.17	$ 398.81	$ 439.88
2018	352.35	429.90	429.75	433.30	437.17	375.67	393.42
2019	331.28	357.83	367.09	370.18	384.39	348.76	347.70
2020	299.06	468.65	462.32	449.48	424.45	508.91	438.69
2021	481.46	518.45	525.01	528.32	541.17	592.21	604.66
Average	354.52	444.87	444.87	444.87	444.87	444.87	444.87
Annual Max/Min Ratio[a]	*1.61*	*1.45*	*1.43*	*1.43*	*1.41*	*1.70*	*1.74*
CV	*0.19*	*0.12*	*0.11*	*0.11*	*0.12*	*0.21*	*0.20*

(a) The annual max/min ratio is the ratio of the maximum and minimum values for 2017-2021.

The MGCC Study Participants note the following observations in response to Table 9 and Table 10.

- Compared to the probability-based functions, if the entire MGCC price were assigned based on Flex Alert events, there would be more variability year-to-year. A Flex Alert event-only price would also have the highest ratio between the largest and smallest annual MGCC totals, whether considered in isolation or combined with MECs. This result confirmed the MGCC Study Participants' decision to use a PCAF-S function for the majority of the capacity price signal, with the Flex Alert event component providing a minority of the signal.
- Among the original PCAF and the three PCAF-S functions, the RMO-based PCAF-S function has the lowest interannual variability when considering the MGCC cost only (Table 9). The PCAF and the W/E PCAF-S functions have the highest variability, with the FA/A PCAF-S function in between.
- However, when MECs are added (in Table 10), the PCAF-S functions and the original PCAF method yield almost identical CV and annual max/min ratios. This is because 2021, which thankfully had lower maximum loads than 2020, had significantly higher gas prices and therefore higher energy prices, which tended to even out the options. Because this combination of lower loads and higher gas prices may not be typical, it seems unlikely that MECs would even out the inter-annual variability over the long run.

Based on the results shown in Table 9, the MGCC Study Participants found that the RMO probability-based PCAF-S function is the only alternative that meets the inter-annual variability standard of a CV less than 0.4, as discussed in Finding 5.7. Furthermore, the recommended PCAF-S function exhibits max/min ratio of annual capacity costs of 2.4, far lower than any of the other alternatives.

6.1.5 Selection of the RMO Probability-Based Function as the Recommended PCAF-S Function

The MGCC Study Participants selected the RMO probability-based function as the recommended PCAF-S function for the following reasons.

- **Lowest maximum price:** The RMO probability-based function has the lowest maximum price over the 2017-2021 period, whether considered alone ($1.19/kWh) or in combination with MECs ($2.12/kWh). MGCC Study Participants are concerned that the potential for extremely high generation prices could scare off potential customers – the combined prices of $4.78/kWh, $3.65/kWh and $5.76/kWh for PCAF-based, FA/A-based and W/E-based rate elements, respectively, are high enough to cause comparisons to prices in Texas during the 2021 freeze event. While those prices occurred for only one hour (in 2020) rather than the multiple days in Texas, "perception is reality" when it comes to customer willingness to sign on to a pilot rate. MGCC Study Participants believe that using the PCAF-based, FA/A or W/E curves would necessitate instituting a price cap on the capacity cost or combined generation cost rate, which would complicate implementation of the rate.
- **Encourages preventative behavior:** The RMO probability-based function increases prices at lower load levels than the alternatives. This will provide a preventative and proactive signal that will increase prices at somewhat lower load levels, encouraging participants to practice behaviors that will help prevent extreme W/E events.
- **Avoids inter-annual variability in revenue collection:** As discussed in Section 6.1.4, the RMO probability-based curve is likely to result in significantly less inter-annual variability in MGCC revenue collection than the alternatives. While inter-annual variability is similar for all the probability-based curves when total generation costs (including MECs) are considered (see Table 10), there is not a significant risk that MEC collections will differ much from costs since hourly MECs represent actual marginal costs. It is expected that a significant advantage of the DAHRTP rate is that energy costs will require little, if any, true-up.

  In contrast, all of the hourly MGCC rate elements represent possible approximations to the true marginal capacity costs, which MGCC Study Participants consider to be ill-defined, or at least only calculable after the fact. The MGCC revenue requirement is set in each rate case and must be collected. Reducing the interannual variability of the MGCC component of the rate will reduce the likelihood and magnitude of revenue under-collections and cost shifting.

Table 11 shows the annual MGCC, the maximum capacity price over 2017-2021, and various annual summary statistics for three alternative combinations of MGCC rate elements, as follows.

- PG&E's original proposed PCAF method
- PCAF-S based on W/E events, plus adders for actual RMOs and Flex Alert events
- Recommended PCAF-S based on RMO events, plus an adder for Flex Alert events

Table 11: Annual Costs for Alternative MGCC Pricing Formulas, 2017-2021
Applied to Net Load and CAISO Day-Ahead Energy Prices

Year	**MEC** CAISO Market	Alternative MGCC Pricing Formulas		
		PCAF PG&E Method	**PCAF-S W/E + RMO & Flex Alert Adders**	Recommended **PCAF-S RMO + Flex Alert Adder**
2017	$ 308.46	$ 141.05	$ 121.00	$ 125.41
2018	352.35	77.55	53.70	79.55
2019	331.28	26.56	25.88	50.06
2020	299.06	169.59	168.89	132.64
2021	481.46	37.00	82.29	64.09
Average	354.52	90.35	90.35	90.35
Annual Max/Min Ratio [a]	*1.61*	*6.39*	*6.53*	*2.65*
CV	*0.19*	0.62	*0.56*	*0.37*

(a) The annual max/min ratio is the ratio of the maximum and minimum values for 2017-2021.

The final form of the recommended MGCC pricing formula is summarized in the next section.

6.2 Recommended MGCC Pricing Formula

As discussed above, the MGCC Study Participants determined that the largest portion of MGCC costs should be recovered through a PCAF-S function that depends on ANL_T, whose maximum value is expected to be 100%, based on a logistical regression of RMO events. The remaining MGCC costs should be recovered through a binary variable (value of 0 or 1) representing whether or not the CAISO calls a DA Flex Alert. As explained at the beginning of Section 3, the hourly price is determined using the variables H (hourly) and E (event) in Equation 2, which are selected to recover the total MGCC in an average year.

In Finding 5.7, the MGCC Study Participants explain why Flex Alerts provide the best DA indication of grid stress conditions that are not well captured by the ANL_T metric. In order to determine what price signal triggered by *actual* DA Flex Alert events should be added to the PCAF-S function, the MGCC Study Participants relied upon the $250/MWh penalty price for ancillary services shortages in CAISO (see Section 4.2.3). Thus, the participant consensus is to include a $0.25/kWh adder for DA Flex Alert hours in the MGCC price signal.

The recommended Hourly MGCC Pricing Formula, Equation 5, is illustrated in Figure 10. The specific values for H, A, and B may be updated by PG&E prior to program launch, reflecting additional historical data or any updates to the MGCC price of $90.35/kW-year. The value for E should only be updated if the CAISO updates the penalty price for ancillary services shortages.

Equation 5: Hourly MGCC Pricing Formula

$$\text{Hourly MGCC Price: PCAF-S}(ANL_T) = H / (1 + \exp(A - B^* ANL_T)) + E * \text{Flex Alert}$$

$$\text{PCAF-S}(ANL_T < L) = 0$$

ANL_T is normalized[54]

$$E = \$0.25$$

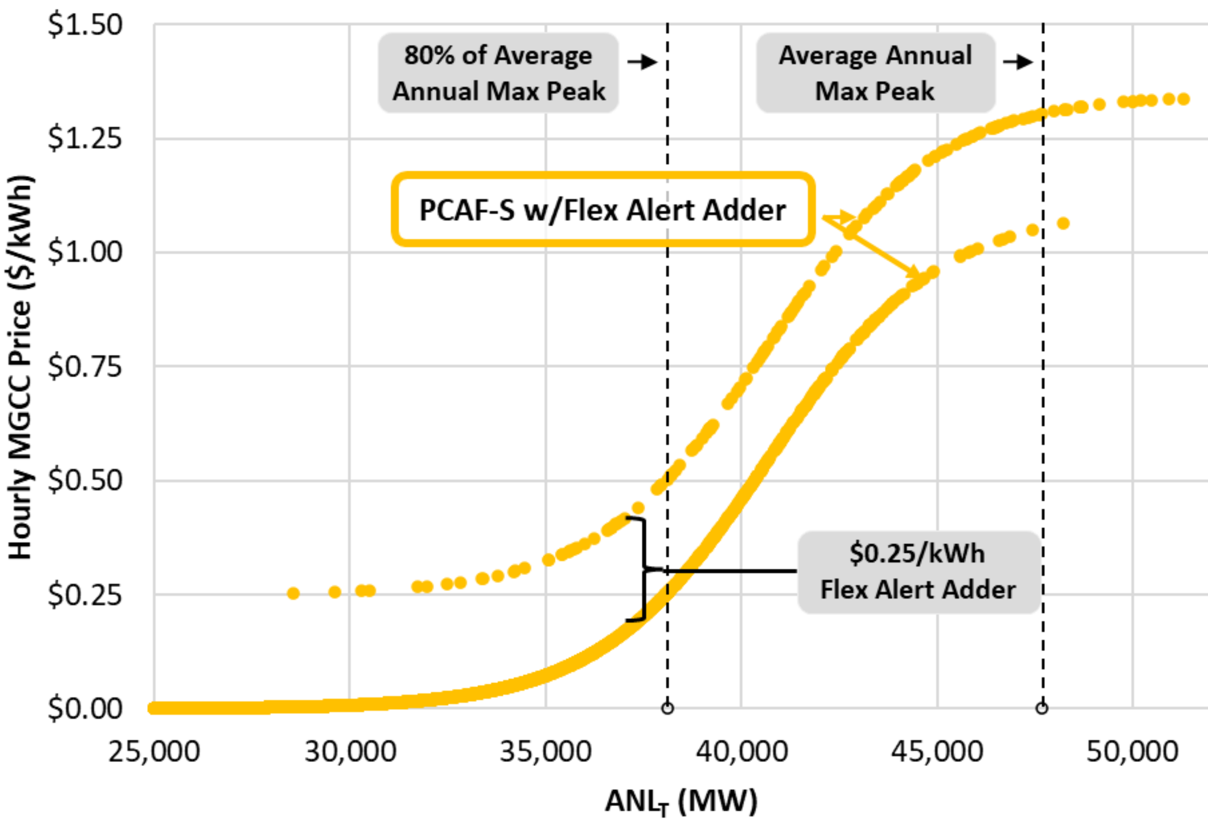
$$H = \$1.097$$

$$A = 18.78$$

$$B = 23.72$$

$$L = 27{,}713 \text{ MW}$$

Figure 10: Hourly MGCC Pricing Formula
Applied to Net Load and CAISO Day-Ahead Energy Prices for 2017-2021



54 ANL_T is normalized using the formula: $(ANL_T - Min)/(Max - Min)$, where Min/Max are the minimum/maximum ANL_T values in the dataset.

As an example of applying Equation 5, during CAISO Flex Alert hours the recommended MGCC rate design would send an average total generation price signal of $1.11/kWh, which is a strong price signal for customers to conserve or shift usage.[55] The recommended MGCC rate design would include the following components:

- **PCAF-S price**: Would have averaged almost $0.62/kWh during FA/A events from 2017-2021
- **Flex Alert adder:** $0.25/kWh
- **Hourly MEC costs:** Averaged $0.24/kWh during FA/A events from 2017-2021

In addition, the RNA will vary by rate and TOU period, potentially providing a complementary increase to the generation price signal during CAISO Flex Alert hours.

The effect of the Flex Alert adder is illustrated in Figure 11, which contrasts a PCAF-S function that collects the full MGCC cost with the recommended combination of a PCAF-S function with a Flex Alert adder for all hours in 2017-2021. The PCAF-S function that collects the full MGCC cost is shown in green, and is the same function illustrated in green in in Figure 8 and Figure 9. The recommended PCAF-S function with a Flex Alert adder is shown as a yellow curve—which appears in two parts because the upper part of the curve indicates hours in which a Flex Alert was called, and the lower part of the curve represents hours without a Flex Alert.

The distance between the two parts of the yellow curve in Figure 11 is exactly $0.25/kWh—the amount of the Flex Alert adder. The green curve separates from the lower part of the yellow curve because in order to collect the same total MGCC value, the variable H in Equation 5 for a formula with no Flex Alert adder (the green curve) is determined to be $1.2/kWh, rather than $1.097/kWh for the recommended formula (the yellow curve).

Note that the Flex Alert adders are rare at lower loads, but do occur during some hours with ANL_T below 30,000 MW. Flex Alerts become more frequent at very high net loads, and applied to all but one of the hours in which the ANL_T exceeded the average annual maximum over 2017-2021. Thus, the proposed final MGCC pricing formula provides a stronger signal than the RMO-based PCAF-S function alone at extremely high net load, without becoming excessive. The proposed MGCC function also provides a noticeable signal at low net load levels whenever there is a (well-advertised) Flex Alert.

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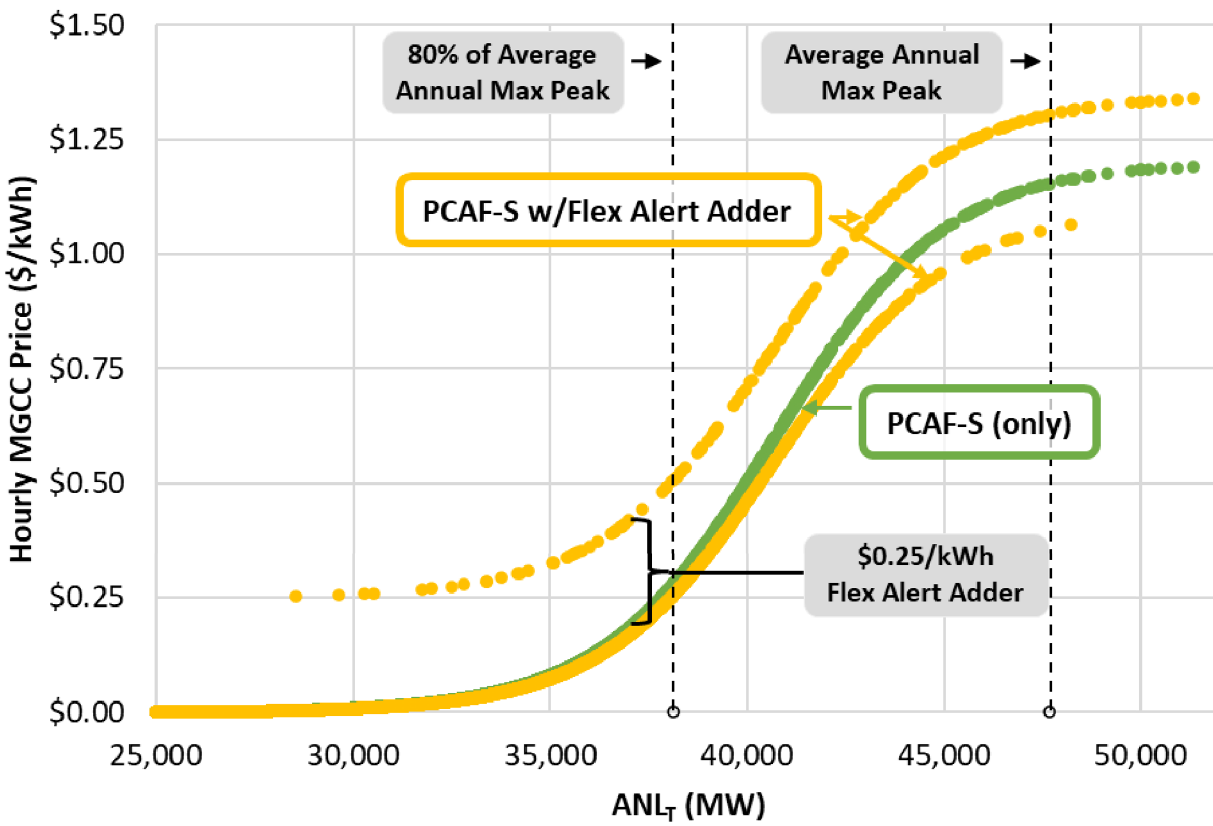
55 This is higher than the $0.285/kWh summer peak generation price for proposed B-6 rates plus $0.60/kWh price adder in PG&E's commercial CPP program. Also, because the RTP price has an hourly shape (concentrating on the hours with the greatest forecasted grid stress) whereas the B-6 rate and its CPP adder are the same for each hour in an event, the maximum generation price under RTP is even higher than $1.11/kWh (see Figure 11, below).

Figure 11: Hourly MGCC Pricing Formula Compared to RMO Probability-Based PCAF-S Function
Applied to Net Load and CAISO Day-Ahead Energy Prices for 2017-2021



To provide additional context, Figure 12 presents the average MGCC in $/MWh by month and HE for the preferred alternative, while Figure 13 presents the same data for MEC. For system conditions in 2017-2021, the MGCC component would have been much more concentrated in the summer peak period (June-September from 4 PM to 9 PM, or HE 17 to 21) than the MEC component. There is some MGCC cost outside the (highlighted) summer peak period, due to high ANL$_T$ or CAISO Flex Alert events.

Figure 12: Average MGCC by Month and Hour Ending for Preferred Alternative in $/MWh, 2017-2021

Month/HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Average
1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0	0	0	0	**0**
2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0	0	0	0	**0**
3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	2	2	1	0	0	**0**
6	0	0	0	0	0	0	0	0	0	0	0	0	0	1	6	13	24	37	61	85	73	29	4	0	**14**
7	0	0	0	0	0	0	0	0	0	0	0	0	1	3	8	24	49	78	140	199	151	54	9	1	**30**
8	0	0	0	0	0	0	0	0	0	0	0	0	1	6	24	66	102	150	243	277	213	92	16	2	**50**
9	0	0	0	0	0	0	0	0	0	0	0	0	1	5	12	33	51	83	144	138	91	36	8	1	**25**
10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4	6	16	23	16	8	4	0	0	**3**
11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0	0	0	0	0	**0**
12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	2	2	1	0	0	0	**0**
Average	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**4**	**12**	**19**	**31**	**52**	**61**	**45**	**18**	**3**	**0**	**10**

Figure 13: Average MEC by Month and Hour Ending for Preferred Alternative in $/MWh, 2017-2021

Month/HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Average
1	33	31	31	31	32	36	44	45	37	32	29	27	25	25	27	33	42	55	54	49	45	41	37	35	**36**
2	42	39	38	38	41	50	64	57	41	33	28	26	23	23	24	31	46	73	88	78	70	62	50	45	**46**
3	30	28	27	27	29	37	46	43	32	23	20	17	15	14	15	18	22	35	52	59	51	44	37	33	**31**
4	26	24	23	23	26	33	40	33	23	18	16	14	12	12	13	14	17	25	40	57	53	42	34	29	**27**
5	25	23	21	21	23	30	32	24	18	16	15	14	14	16	17	19	21	27	40	55	57	43	33	28	**26**
6	30	27	26	25	27	30	31	23	19	19	20	22	25	28	30	33	37	42	56	78	61	47	36	32	**34**
7	37	34	33	32	32	35	37	31	27	28	31	33	37	40	44	48	55	64	86	111	75	57	44	40	**45**
8	40	37	36	35	35	38	43	38	31	31	33	36	39	42	46	52	57	72	116	123	74	56	47	42	**50**
9	39	38	36	36	37	40	45	42	33	30	30	32	35	38	41	45	49	64	97	83	60	50	45	42	**45**
10	42	40	38	38	39	44	52	53	42	37	36	35	36	38	40	42	48	76	98	76	60	54	48	44	**48**
11	43	41	40	40	42	49	57	50	41	37	35	34	34	35	38	47	62	85	71	62	57	52	48	45	**48**
12	43	41	40	40	42	47	57	55	46	41	39	36	35	35	38	47	60	76	69	64	60	54	50	45	**48**
Average	**36**	**34**	**32**	**32**	**34**	**39**	**45**	**41**	**32**	**29**	**28**	**27**	**27**	**29**	**31**	**36**	**43**	**58**	**72**	**74**	**60**	**50**	**42**	**38**	**40**

7 BILL IMPACT ANALYSIS FINDINGS

From the customer's perspective, the most important aspect of an RTP rate is likely its impact on their bills. MGCC Study Participants therefore considered both average generation-related bills and their expected volatility, or year-to-year variability. This analysis relies on historical load and market energy price data because, even if suitable hourly forecast data were available, the hourly effects of the Flex Alert event adder cannot be forecast. The most recent five years (2017-2021) were used for this analysis for consistency with the underlying MGCC analysis.

Moreover, while this MGCC Study is intended to inform all of PG&E's RTP rates under consideration (BEV-1 and 2; and B-20, B-6, and E-ELEC under consideration in A.19-11-019), the bill impact analysis considers only Schedule B-6, for the following reasons:

- The Residential E-ELEC rate was just adopted in D.21-11-016 and does not yet have any customer load data, making it impossible to calculate an accurate expected bill under the existing or RTP version of the rate at this time.
- Likewise, the BEV-1 and 2 rates did not exist in 2017, so the first part of the comparison period would need to be filled in with data from other classes. Moreover, commercial EV charging is still relatively new, so there are few customers, but with a variety of very different load shapes for the various use cases (transit, workplace charging, etc.), which can lead to large changes in the class load characteristics from year to year since the class is growing.
- B-20 has demand charges, which complicates bill calculations because class-average loads cannot be used due to their reduced volatility compared to individual customer bills.

Thus, the B-6 rate[56] was chosen as the Otherwise Applicable Tariff (OAT) for this analysis, using its primary voltage parameters (as it is the middle of the three options) as determined by D.21-11-016 included in a recent PD as described in Section 3.

The bill impact analysis also considers the impact of the RNA. The RNA is designed to make the RTP rate revenue-neutral in each TOU period, with two exceptions. The RNA should not be inverted (e.g., the off-peak RNA set higher than the peak RNA) and the RNA value should not drop below the Renewable Energy Certificate (REC) adder, in which case it is set to the REC adder.

The RNA has been recalculated using updated Schedule B-6 OAT rates for the entire 2017-2021 period (instead of just 2017 for the original RNA analysis), as shown in Table 12. PG&E's recalculation was necessary because the updated B-6 rates have a significantly higher differential between peak and off-peak than the B-6 rates in place in March 2020, which were the basis for calculating the (flat) RNA for PG&E's initial RTP testimony. PG&E's updated RNA determination also incorporates the actual MECs

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56 Even the B-6 rate has complications – B-6 is a new rate as of 2019 (with a new peak period), whose customers initially came from the A-6 rate but more recently have been drawn from A-1 customers. Thus, even using load shapes from A-6 plus B-6 customers is problematic. To provide a more apples to apples comparison across years, the average load shape by hour was drawn from the approximately 13,000 current B-6 customers who were also customers in 2017 (on a different rate). This relatively stable cohort represents the great majority of current B-6 customers.

for 2017-2021, the proposed MGCC pricing formula, and updated average loads from a stable cohort of customers currently on the B-6 rate. The original RNA had been set to the REC adder in each TOU period; the updated RNA exhibits significant differentiation, which will be advantageous for battery storage economics.

Table 12: Original and Revised RNA for B-6 RTP Rate ($/kWh)

TOU Period	Original RNA	Revised RNA
Summer Peak (Jun-Sep, 4-9 PM)	$ 0.00519	$ 0.05996
Summer Off-Peak (All other hours)	0.00519	0.01486
Winter Peak (Oct-May, 4-9 PM)	0.00519	0.01542
Winter Off-Peak (All other hours)	0.00519	0.00621
Spring Super Off-Peak (Mar-May, 9 AM-2 PM)	0.00519	0.00621

Average customer bills were calculated by multiplying the proposed MGCC, MEC and their sum for each hour in 2017-2021 by the average hourly load per customer in the B-6 cohort.[57] Bills were calculated both before and after the modeled operation of a 5-kW, two-hour-duration battery.[58]

7.1 FINDING: Customers are Unlikely to Experience a Substantial Increase in Inter-Annual Bill Variability After Migrating to a DAHRTP Rate Using the Recommended MGCC Pricing Formula.

The total bill inter-annual variability of the recommended MGCC pricing formula is almost exactly the same as for the OAT, regardless of whether the prototypical customer has a battery storage device, as shown in Table 13. While customers may see some increase in *monthly* bill variability, particularly in months with high ANL_T and Flex Alert events, it appears unlikely that customers will experience a substantial increase in inter-annual bill variability as a result of migrating from the OAT to a DAHRTP rate.

This somewhat surprising finding is a result of two sources of stability. First, when considering the total bill, a substantial portion of the total bill is not affected by a generation-only DAHRTP rate.

Second, the RNA included in the DAHRTP rate stabilizes the inter-annual variability associated with the recommended MGCC pricing formula, by adding a bill component that varies by TOU period but not by year. As shown in Table 13, the CV for the generation portion of a Schedule B-6 bill using the

57 Data for the last two months of 2021 were not available and were filled in using data from the last two months of 2020. Average loads were calculated by dividing total load by the number of customers in the B-6 cohort for each month.

58 Average load for this pool of customers is approximately 4 kW. Many potential RTP customers are NEM customers whose load is at minimum mid-day and at maximum during the evening peak; the typical customer would likely use a battery targeted to supply about 4 kW. The MGCC Study Participants chose to model a 5 kW, 2-hour battery operation, representing a customer with a single Tesla Powerwall (the most popular unit for BTM batteries) who reserves some of the Powerwall's 2.7-hour duration for resiliency from outages or to increase the battery's longevity by keeping the battery between 15% and 85% state of charge.

recommended PCAF-S formula and a Flex Alert event adder is 0.11, much lower than the 0.4 standard determined in Finding 5.7.

The CV of 0.11 for the total generation portion of the Schedule B-6 bill is roughly equal to the CV for the recommended RMO probability-based PCAF-S function alone. This result indicates that the stability provided by the RNA component of the generation rate happens to offset the somewhat higher inter-annual variability driven by the inclusion of the Flex Alert adder.

7.2 FINDING: A Prototypical Customer is Likely to Experience Similar Average Bills After Migrating to a DAHRTP Rate.

The MGCC Study Participants estimated the average bill for a Schedule B-6 customer using the OAT, recommended and alternative MGCC pricing formulas, and PG&E's original PCAF method. As shown in Table 13, all of the RTP alternatives yield average generation-only and total bills that are almost identical to the OAT over the 2017-2021 period.

For the recommended MGCC alternative this is because the RNA was updated to obtain equal revenue to the OAT, but the other RTP alternatives also almost exactly match the OAT's average bill. With the addition of a battery, the RTP rates yield bills that are approximately 1% lower than the OAT in total bill (and would be approximately 4% lower for the generation portion).

In the high-grid-stress year 2020, customers fare best with the OAT or the recommended MGCC pricing formula in the absence of a battery (or any price-responsive load shifting). Customers with a battery fare best on the recommended MGCC RTP rate.

However, in 2021, customers would fare best with the OAT with or without a battery because MECs were significantly higher than the five-year average. The OAT does not pass through above-average (or below-average) MECs in the same year—but because customers on the OAT are subject to energy cost reconciliation through an annual true-up, those benefits would not be retained.[59]

59 As part of the DAHRTP pilots, the relationship between the RTP rate and the ERRA balancing account will be examined in the final evaluation report. PG&E GRC2 RTP Track Settlement (Jan. 14 Settlement), Appendix A, Attachment B, "Background and Conceptual Details of PG&E's Generation Revenue Over and Under-Collection Study."

Table 13: Generation-Only and Total Bills for an Average B-6 Customer With and Without 2-hr Battery
Applied to Net Load and CAISO Day-Ahead Energy Prices, 2017-2021.

	OAT			PCAF PG&E Method			PCAF-S W/E + RMO & Flex Alert Adders			Recommended PCAF-S RMO + Flex Alert Adder		
Bill Type:	Generation	Total	Total w/Battery	Generation	Total	Total w/Battery	Generation	Total	Total w/Battery	Generation	Total	Total w/Battery
2017	2,610	9,116	8,821	2,744	9,250	8,747	2,620	9,126	8,727	2,629	9,135	8,712
2018	2,452	8,597	8,302	2,371	8,515	8,143	2,240	8,384	8,093	2,372	8,516	8,167
2019	2,320	8,088	7,793	1,896	7,664	7,417	1,883	7,650	7,443	2,015	7,783	7,496
2020	2,109	7,388	7,093	2,314	7,592	6,976	2,298	7,577	7,060	2,126	7,404	6,934
2021	2,276	7,841	7,547	2,486	8,050	7,708	2,710	8,275	7,898	2,625	8,190	7,803
Average	**2,353**	**8,206**	**7,911**	**2,362**	**8,214**	**7,798**	**2,350**	**8,202**	**7,844**	**2,353**	**8,206**	**7,822**
vs. OAT	**-**	**-**	**-**	**9**	**9**	**(113)**	**(3)**	**(3)**	**(67)**	**0**	**0**	**(89)**
CV	*0.072*	*0.073*	*0.076*	*0.117*	*0.075*	*0.078*	*0.126*	*0.069*	*0.073*	*0.107*	*0.073*	*0.077*

7.3 *FINDING: Profit Opportunities for Battery Storage Systems are Likely to Increase With Use of the Recommended MGCC Pricing Formula.*

PG&E's RTP design rates are expected to both incent battery operation that helps the grid and promote customer adoption of battery storage by providing a greater return on investment for customer-installed batteries than the OAT. The expectation that the combination of the MGCC and MEC rates will incent battery operations and other customer behaviors that help the grid is set out in this study's findings (Section 5) and the process of designing the MGCC pricing formula (Section 6). To investigate the return on investment for customer-installed batteries, the operation of a prototypical battery storage unit was modeled under various versions of the MGCC pricing formula and compared to the OAT.

For simplicity, the battery was assumed to discharge during the two highest-priced hours of the day (considering the entire tariff, not just the generation portion) and charge during the two lowest-priced hours, except that the charging cost was increased by 20% to account for round-trip efficiency losses and battery degradation. On days when the battery would have lost money from this operation, it was assumed to stay idle.

Table 14 shows the annual bill savings, or "profit," in dollars per year for a 5-kW battery discharged at most 2 hours per day, for the OAT, PG&E's original PCAF-based MGCC method, and the two alternative combinations of MGCC rate elements shown in Table 11. As noted in Section 7.2, the combination of a battery and the recommended MGCC RTP rate performs better than the OAT in most but not all conditions reflected in the 2017-2021 period.

Table 14: Battery Savings for Alternative MGCC Pricing Formulas
Applied to Net Load and CAISO Day-Ahead Energy Prices, 2017-2021.

Year	**Battery Value (5-kW, 2-hour)**			
	OAT	**PCAF** PG&E Method	**PCAF-S W/E + RMO & Flex Alert Adders**	**Recommended PCAF-S RMO + Flex Alert Adder**
2017	$ 294	$ 503	$ 399	$ 422
2018	294	371	291	349
2019	294	247	207	287
2020	294	616	517	471
2021	294	342	376	387
Average	**294**	**416**	**358**	**383**
CV	*0.00*	*0.31*	*0.29*	*0.16*

As expected, each MGCC pricing formula alternative provides greater savings for the modeled battery than the OAT. Under the B-6 OAT, the battery savings is approximately 45 cents or less per day during the winter and spring when there is a lower-priced Super Off-Peak period, and approximately $2.00 per day during the summer. Under the two PCAF-S alternatives and PG&E's original PCAF method, battery savings varies from day-to-day, sometimes with no savings opportunity, but savings increase on the highest-priced day to as much as $22/day for the recommended DAHRTP rate (and as much as $47/day for PG&E's original PCAF method) based on 2017-2021 conditions. As a result, the average battery savings for the recommended DAHRTP rate is $383 per year, compared to $294 per year for the Schedule B-6 OAT.

The MGCC Study Participants view these results as confirming their recommendation to adopt an RMO probability-based PCAF-S formula, for the following reasons.

- Even though the original PCAF-based alternative yields the most battery value, it has much greater variation year to year. The PCAF-based alternative results in a 9% increase in battery savings relative to the recommended MGCC pricing formula, while the PCAF method increases volatility (CV) in bill savings to the customer by 94% (CV of 0.31 compared to 0.16).
- The MGCC pricing formula using a W/E probability-based PCAF-S function, an RMO adder, and a Flex Alert adder provides 7% less expected bill savings and a 81% increase in bill savings volatility. Because the RMO and Flex Alert adders generally apply for many hours in a day, the resulting MGCC price is relatively flat over the entire peak period. The battery can only discharge in two of the five peak-period hours, limiting bill savings opportunities during event days.
- The recommended RMO probability-based PCAF-S formula with a Flex Alert adder has a shape that is more responsive to forecast ANL_T and therefore generates higher prices for the top two hours of a day during periods with high loads and high levels of grid stress.

8 SUMMARY OF RECOMMENDATIONS

The MGCC Study Participants recommend that the Commission adopt the recommendations below, based on the analysis in this MGCC Study. It is also hoped that the parties to A.20-10-011, CEV rates, and A.19-11-019, its GRC Phase II will provide their support.

The MGCC Study Participants specifically recommend the CPUC adopt the following formula for setting the MGCC price in PG&E's DAHRTP rate:

Equation 6: Hourly MGCC Pricing Formula

$$\text{Hourly MGCC Price: PCAF-S}(ANL_T) = H / (1 + \exp(A - B^* ANL_T)) + E * \text{Flex Alert}$$
$$\text{PCAF-S}(ANL_T < L) = 0$$

ANL_T is normalized[60]

$$E = \$0.25$$
$$H = \$1.097$$
$$A = 18.78$$
$$B = 23.72$$
$$L = 27{,}713 \text{ MW}$$

The MGCC Study Participants anticipate that the specific values for H, A, B, and L may be updated by PG&E prior to program launch, reflecting additional historical data or any updates to the MGCC price of $90.35/kW-year, using the methods described in this report.[61] The value for E should only be updated if the CAISO updates the penalty price for ancillary services shortages.

Furthermore, the MGCC Study Participants recommend that the Commission and the Parties accept our finding that the inter-annual variability of generation rates resulting from the use of the recommended MGCC price will be reasonable and consistent with other capacity-related metrics, and the consequence that inter-annual variability of total bills is likely to be similar to that of the Original Applicable Tariff.

The MGCC Study Participants also suggest that as part of the final evaluation of the two DAHRTP programs, PG&E should re-convene the MGCC Study Working Group to re-evaluate the MGCC pricing formula. The Participants hope that both lessons learned from the application of the formula, and the potential availability of SERVM datasets that are better suited to this analysis, may also provide opportunities to improve the MGCC pricing formula.

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60 ANL_T is normalized using the formula: $(ANL_T – \text{Min})/(\text{Max} – \text{Min})$, where Min/Max are the minimum/maximum ANL_T values in the dataset.

61 The hourly price is determined using the variables H (maximum price contribution from the hourly "PCAF-S" function of ANL) and E (event-based adder), which are optimized to recover the total MGCC of $90.35/kw-year in an average year, and the variables A and B are determined using logistic regression using historical data, as explained in Section 3.

MGCC Study Participants recognize that the import limits used in the SERVM model reflect existing import RA contracts. It is likely that the CAISO market may import energy higher than RA contract levels, particularly when net loads in the rest of the WECC are not extremely high. Ideally a robust WECC model would reflect resource plans of all LSEs and simulate market frictions to replicate WECC wide operation. In the absence of a robust WECC wide model of non-CAISO entities' resource plans, MGCC Study Participants offer a recommendation to use historical import levels correlated with LSE NL from the balance of the WECC to inform modeled maximum imports.