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PG&E Comments on Revised CED Forecast 2018-2030

Additional submitted attachment is included below.

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Re: Docket 17-IEPR-03: Pacific Gas and Electric Company Comments on the California Energy Demand 2018-2030 Revised Forecast

Pacific Gas and Electric Company (PG&E) appreciates the opportunity to provide comments on the California Energy Commission's (CEC) California Energy Demand (CED) 2018-2030 Revised Forecast (Revised Forecast). The CED Forecast is a critical component of the Integrated Energy Policy Report (IEPR) and an essential tool for planning future energy policies across numerous agencies. Given this importance, PG&E appreciates the continued efforts of CEC Staff to discuss and refine components of the 2018-2030 Forecast with stakeholders through the Demand Analysis Working Group (DAWG). However, PG&E continues to have concerns about elements of the forecast, including representations of current conditions, and questions about underlying assumptions. These concerns are exacerbated by the limited time PG&E and other stakeholders have had to review the Revised Forecast – in some cases, stakeholders have had just a week to review and provide comments on certain forms, including the Community Choice Aggregation form, where significant differences remain between the CEC's forecast and PG&E's.

Key points of PG&E's comments include:

- Community Choice Aggregation (CCA) must be revisited prior to adoption of the forecast to reduce the risk of significant financial impact on PG&E's bundled customers;
- Key assumptions and forecast inputs should be made available to stakeholders so that the Revised Forecast can be adequately reviewed; and,
- Long-term methodological considerations are provided.

PG&E looks forward to continuing to work with staff to address PG&E's significant concerns on the Revised Forecast with the goal of PG&E being able to support the adoption of the CED 2018-2030 Forecast at the February 21, 2018 Business Meeting.

I. Community Choice Aggregation Forecasting Must Be Revised to Include Significant Near-Term Known Events and to Appropriately Capture Future Growth

As PG&E has pointed out in its August 15, 2017 comments on earlier forecast versions in this IEPR and reiterates here, the CEC's forecast, as presented in the *CED 2017 LSE and BA Tables Mid Baseline Demand Statewide, No AAEE-AAPV*[1], significantly underestimates the load that existing CCAs are currently serving customers, and also underestimates the potential for incremental CCA formation within PG&E's service territory. The Forecast must be updated to reflect more accurate load values for existing CCAs and to more appropriately account for additional future formations.

PG&E appreciates that the CEC's Revised Forecast report acknowledges the "increasingly prominent role [that CCAs play] in California's energy future,"[2] and that CEC has updated its assessment to include the 12 CCAs currently in operation (up from three when CED 2015 was developed). Yet, there remain significant differences – more than 5,000 GWh in the 2018 forecast, the year we know the most about – between the CEC's forecast and that submitted by PG&E in April 2017. The forecast methodology is also flawed in that the CEC has forecast CCA growth over the 2018 to 2030 period will be at the same level as the incumbent load serving entity (LSE). Given the CCA would be serving customers that were formerly served by the LSE, and significant and rapid escalation in CCA growth has been and continues to be observed, assuming the same growth level will significantly underestimate CCA growth.

The CEC must update the 2018-2030 Revised Forecast to more accurately reflect the details of CCAs currently in operation, the near-term acceleration of CCA growth, and the communities expected to transition to a CCA program. The differences are not insignificant given the 5,000 GWh referenced above represents more than a 40% difference between the CEC's lower CCA departure forecast and PG&E's forecast. Such a significant difference in the mid-baseline case forecast is untenable. PG&E's forecast includes information actually shared with PG&E by CCAs and is used in CPUC rate-setting proceedings. PG&E has repeatedly expressed its concerns about the gap between the two forecasts and presented details of its CCA forecasting approach to Staff via a DAWG meeting and also under a non-disclosure agreement to assist the CEC in this undertaking. Failure to adjust the CCA forecast could result in PG&E being compelled to procure more energy and capacity than are necessary for its bundled customers, thereby adversely impacting customer rates if non-bypassable charges (NBC) are not effective in maintaining indifference. PG&E cannot support adoption of the forecast in its current state, given the potential to adversely impact its bundled customers.

A. Probabilistic Modeling Better Captures CCA Departures

As previously shared with CEC Staff, PG&E uses a probabilistic modeling approach to forecasting CCA departures that has proven to be effective. This model is integral to PG&E's standard load forecasting methodology and informs its planning processes. Load forecasts incorporating this

[1] http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-03/TN222362_20180125T101932_CED_2017_LSE_and_BA_Tables_Mid_Baseline_Demand_Statewide_No_AAE.xlsx

[2] "The California Energy Demand 2018-2030 Revised Forecast," CEC Draft Staff Report (TN#222287) p. 46

approach have been filed in numerous CPUC proceedings (e.g., Diablo Canyon Power Plant (DCPP) Retirement Application, Renewable Portfolio Standard (RPS) Plan, and Energy Resource Recovery Account or ERRA) as well as in PG&E's submission to the CEC's 2017 IEPR proceeding in April 2017, as reflected in Table 1 below.

The probabilistic modeling approach reflects the near-term acceleration of CCA growth by incorporating forecasts submitted by the CCAs as part of a meet-and-confer process developed for the year-ahead forecast submitted in June 2017 as part of PG&E's 2018 ERRA proceeding[3], which is consistent with the year-2018 forecast as filed in PG&E's 2017 IEPR submission. As part of the ERRA proceeding, PG&E received forecasts from five existing CCAs (denoted with asterisks in Table 1 below).

These forecasts were updated in the November 2017 update to the 2018 ERRA[4], which reflects the potential for significant near-term acceleration of CCA load in 2018. This updated forecast includes additional CCA-submitted forecasts and indicates more than 23,000 GWh of load could be served by CCAs in 2018. It would be imprudent to adopt a forecast that is significantly at odds with current information and far less than the forecast that PG&E submitted to the CEC in the IEPR. At a minimum, the CEC should update the CCA forecast to reflect PG&E's 2018 forecast levels in Table 1 below.

PG&E's IEPR submission captures the CCAs' own energy forecasts, while the CEC's forecast does not. Table 1 compares the CEC's 2018 Forecast (Mid Baseline) of CCA load to PG&E's 2018 forecast from the ERRA application (June 2017 filing). There is a significant gap between the two forecasts, which continues into the long-term forecast horizon, as illustrated in Table 2 below.

Table 1

[3] A.17-06-005, June Filing, Chapter 2 "Sales And Peak Demand Forecast" p. 2-12
[4] A.17-06-005, November Update, p. 2-5, Table 2-3

Comparison of 2018 Community Choice Aggregation Levels – CEC v. PG&E

CCA	CEC – 2018 (GWh)	PG&E's Submission – 2018 (GWh)	Delta (GWh)
Existing CCAs	**9,286**	**14,190**	**4,904**
Marin Clean Energy	3,912	2,743*	-1,169
Sonoma Clean Power	2,097	2,574*	477
Clean Power San Francisco Clean	175	545	370
Peninsula Clean Energy Authority	145	3,675*	3530
Silicon Valley Clean Energy	2,587	3,566*	979
Redwood Coast Energy Authority	370	671*	301
County of Contra Costa[5]		416	416
CCAs Starting Service in 2018	**3,483**	**3,417**	**-66**
County of Placer / Pioneer Community Energy	1,006	265	-741
County of Alameda (East Bay Community Energy)		1,301	1301
County of Yolo (Valley Clean Energy)		171	171
Monterrey Bay Community Power Authority	2,477	1,187	-1290
City of San Jose		493	493
Prospective CCAs	**0**	**645**	**645**
Counties of Santa Barbara and San Luis Obispo		557	557
County of Lake		88	88
TOTAL	**12,769**	**18,251**	**5,482**

This near-term difference is exacerbated over the long-term forecast period by also inappropriately concluding that the CCA load grows at the same rate over the forecast period as the incumbent LSE. PG&E's probabilistic model considers publically available information as well as inputs from the CCA to derive a long-term CCA forecast. While the difference in the near-term may be a function of accessing the best available information, the CEC's forecasting methodology only exacerbates the near-term delta of more than 5,000 GWh in the long-term forecast, so that by 2028, the difference between PG&E's forecast and the CEC's forecast is more than 25,000 GWh.

PG&E recommends that the CEC adopt PG&E's probabilistic methodology to more appropriately account for future formation of CCAs and thereby mitigate potential impact to the company's bundled customers. Given these forecasts are used to inform long-term procurement needs, such

[5] County of Contra Costa was tracked as a separate entity and later decided to join MCE

wildly different forecasting results could inappropriately shift procurement obligations and costs to bundled customers, which is not acceptable.

Table 2
Comparison of CCA Levels over the Forecast Period 2018-2030

Long Term CCA Forecast	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
PG&E	18,251	27,151	30,240	32,912	35,244	36,197	36,770	37,322	38,009	38,744	39,391
CEC	12,769	12,735	12,873	12,988	13,144	13,274	13,377	13,518	13,626	13,735	13,833
Delta (GWh)	**5,482**	**14,416**	**17,367**	**19,924**	**22,100**	**22,923**	**23,393**	**23,804**	**24,383**	**25,009**	**25,558**

B. Accounting for CCA After-the-Fact Harms Bundled Customers

PG&E interprets the CEC's comment that "More [CCAs] are expected and could be included, but rather than attempt to forecast additional new arrivals and associated load, staff will revise CCA projections to account for any new entries in the IEPR forecast update to be developed later this year[6]," to mean that the CEC will only include CCA migration after they form and have already started to serve load. Such an *ex post* deterministic method of forecasting is problematic for energy procurement planning by PG&E and other LSEs affected by CCA formation.

Only accounting for new entries after arrival could significantly impact PG&E's bundled customers as the CEC's electricity demand forecast informs long-term planning proceedings (e.g., Long-Term Procurement Plan (LTPP), Integrated Resource Planning (IRP), and the Bundled Procurement Plan (BPP)). In the absence of accurate forecasts of future CCA formations, PG&E could be compelled to procure more energy and capacity resources than necessary for its bundled customers, thereby adversely impacting rates if non-bypassable charges (NBC) are not effective in maintaining indifference. Adoption of PG&E's probabilistic methodology, which has been shared with CEC staff, would help to mitigate harm to utility customers.

II. Forecast Assumptions and Inputs Should be Clarified

PG&E appreciates the continued engagement of staff with LSE stakeholders in their development and refinement of the CED Forecast. However, it is difficult to fully evaluate the Revised Forecast due to the limited time for review, the absence of key files, and a lack of clarity regarding important assumptions and model inputs. Several essential elements that appear to be missing and are therefore impairing PG&E's ability to fully evaluate the Revised Forecast are detailed below.

A. Energy Efficiency

[6] "The California Energy Demand 2018-2030 Revised Forecast," CEC Draft Staff Report (TN#222287) p. 46

Page 10, Decay Assumptions: The implied decay in energy efficiency (EE) savings appears to be very aggressive. PG&E requests that CEC more explicitly define the decay parameters and reference the appropriate supporting research or studies.

Pages 36-37, Figures 17 and 18: Figures 17 and 18 do not explicitly refer to any decay assumption, but the drop-off is much faster than expected if considering only simple EUL retirements. The chart shows that 90% of all savings installed by 2018 is no longer providing savings 12 years later (2030). PG&E requests that the CEC clarify how it arrived at such a dramatic decline rate for savings.

Page 50, Marketing Effects: PG&E requests that CEC provide specific references for the sources of the Marketing Effects factors and values. The report currently provides only a general reference to "several studies on new technology market penetration."

Page 68, Tables 17 and 18: To contextualize the results of the scenarios, it would be helpful to present a comparison of the results to the statewide literal doubling target for SB-350 target as established by the CEC. The same comment applies to Tables 23 and 24.

B. Rooftop Solar PV

Chapter 2, Additional Achievable PV:

General, PV Addressable Market in Low Load Scenario: PGE& requests that CEC clarify whether the base PV forecast or AAPV includes conditions in which the addressable market for rooftop solar PV is expanded through policy actions, such as expansion of virtual net metering to make PV available to renters or low income/CARE customers. Such policies are currently being advocated for by some parties as part of the NEM 2.0 proceeding at the CPUC, and as such, it is not unreasonable to consider them in developing high-PV planning scenarios. To more fully account for the upper end of potential PV adoption, PG&E recommends the CEC include in its low demand scenario policy assumptions that significantly expand the customer PV market.

General, PV Programs: PG&E requests that the CEC clarify whether programmatic adoption (i.e., SASH, MASH and SOMAH) was factored into the PV forecast. If these programs were not included in the forecast, please clarify the rationale.

Pages 75, A-2, A-6, A-7: PG&E requests that the CEC clarify and provide additional detail regarding the basis for and the geographic specificity of the capacity factors/generation profiles used in converting PV adoption into generation. Footnotes 69 (page 75) and 104 (page A-7) appear to provide disparate references for the PV capacity factors/generation profiles.

Page A-5, PV Prices: It is unclear why Tracking the Sun VIII is used as the source for PV price data when two newer versions (IX and X) exist.

Page A-18, PV System Sizing Assumptions: PG&E requests that the CEC describe the source and values used for the PV system sizing assumptions in the estimation of the AAPV forecast. The text simply states that CEC "used PV system sizes as recommended by staff in the Commission's Energy Efficiency Division." The current level of detail is insufficient to evaluate the forecast.

C. Electric Vehicles

Page 77, Charging Profiles: The reference provided in footnote 71 does not contain a specific reporting of the LBNL charging profiles. PG&E requests that CEC provide additional details on the specific charging profile and methods. Without this information, it is challenging to understand and validate the conversion of the vehicle fleet into system peak impact.

PG&E requests that CEC make available for review its assumptions informing the conversion of VMT to kWh/car/day to provide sufficient background to review/comment on these key assumptions that underlie the EV consumption forecast. PG&E also requests that CEC clarify whether the assumptions around VMT and conversion to consumption evolve or are static over time.

III. Methodological Modifications Should be Considered for Future Forecasts

Given the importance of the CED Forecast, PG&E recommends the following methodological modifications to help ensure that future Forecasts are as rigorous and accurate as possible.

Chapter 3, Forecasting Weather-Normalized Consumption Loads: When creating the consumption peak, it appears that the error term in the regression was not considered. CEC does not specify the variance of the error term, and may be understating the peak by not considering it.

Solar PV, Peak Forecasting Methodology: In its forecast of consumption, the CEC method accounts for the variability in both usage and weather and then derives an appropriate peak. However, the methodology applied to PV involves smoothing out variability. Given that month, hour, temperature, and cloud cover are all variables in the consumption model, it may be preferable to also tie the PV generation to the specific weather pattern and net the two to derive a peak.

Solar PV, Generation Profiles: PG&E proposes that CEC reassess its customer PV generation profiles in the next round of forecast model updates. Calibration of the CEC's PV generation profiles to PG&E's generation profiles, which were informed by meteorological data and metered data from PV systems in PG&E's service territory, suggests that the CEC's generation profiles may be significantly overestimating PV system production.

Electric Vehicles, Market Segmentation Approach: PG&E requests that CEC clarify whether the "rideshare" market (e.g., Lyft, Uber) is accounted for in the forecast. This factor may be an important consideration as the rideshare market grows, because rideshare vehicles are expected to exhibit distinct consumption and charging patterns from conventional EVs. As the rideshare market is relatively new, its characteristics as they relate to the EV consumption and load may not be adequately captured in historic sources of data used for the forecast input/assumptions. If this factor is not currently accounted for, then PG&E requests that CEC consider the impact of this factor in future forecast iterations.

IV. Recommended Minor Edits

PG&E recommends the following adjustments to help with clarity and accuracy in the final Forecast document.

Page 70: The following edit appears to reflect the intent of the paragraph: "Figure 38 shows the additions to statewide PV capacity for each of the scenarios. The seeming reversal in order (low AAPV has more additions than high AAPV) is due to the difference in new homes subject to the regulations given adoptions in the baseline forecast. In the high demand-low AAPV scenario, a ~~greater~~ **lesser** percentage of new homes are projected to adopt PV in the baseline, leaving ~~less~~ **more** homes available for the regulations."

Pages 75 and A-7: Reconcile or clarify footnotes 69 (page 75) and 104 (page A-7). These appear to provide disparate references for the PV capacity factors/generation profiles.

Page 78, Figure 41: The y-axis label should read "Percent of Daily Load" not "Percentage of Daily Charging".

Chapter 4, Electric Vehicles: PG&E requests that CEC present EV peak and consumption results by service territory. This appears to be embedded in the LSE-specific sales figures, but warrants independent consideration as it is a relatively new and high-impact variable in the overall forecast.

Page A-7, Footnote 105: This footnote should be updated to read: Tracking the Sun ~~XIII~~ **VIII**

XII. Conclusion

PG&E appreciates the opportunity to provide comments on the California Energy Demand 2018-2030 Revised Forecast and looks forward to the CEC's response to requested modifications and clarifications ahead of February's proposed adoption of the Forecast.

Sincerely,

/s/

Wm. Spencer Olinek