Docket No. A.19-11-019

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Date: November 20, 2020

Witness: Richard McCann, Ph.D.

DIRECT TESTIMONY OF
RICHARD McCANN, PH.D.
ON MARGINAL COSTS, REVENUE ALLOCATION, AND RATE DESIGN ISSUES ON BEHALF OF
THE AGRICULTURAL ENERGY CONSUMERS ASSOCIATION

PUBLIC VERSION

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company to Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design.	**)** **)** **)**	**A.19-11-019**

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Statement of Qualifications: Richard McCann, Ph.D.

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1. Introduction

The Agricultural Energy Consumers Association (AECA) is a nonprofit organization that represents the energy interests of California agriculture. AECA was founded in 1991 by growers and other members of the agricultural community concerned about rapidly rising electricity costs. AECA represents the collective interests of the state's leading agricultural associations and works on behalf of the combined interests of several county Farm Bureaus and more than forty agricultural water districts. AECA's membership is broad-based, reflecting family farmers from Redding in the north to San Diego in the south who grow crops ranging from alfalfa to walnuts. Through its members and membership associations, AECA represents in excess of 40,000 California agricultural producers.

AECA has presented testimony in numerous General Rate Cases (GRC) that demonstrate that Pacific Gas and Electric Company (PG&E) has consistently overestimated the costs to serve agricultural customers. PG&E has yet again failed to address systematic problems with the data and methodology on which it relies to estimate costs of service to the agricultural sector. Moreover, a careful examination of PG&E's filing reveals inconsistencies both within workpapers and between this docket and PG&E's recorded data and forecasts in its Energy Resource Recovery Account (ERRA) proceeding.[1]

These discrepancies undermine the credibility of PG&E's calculations and parties' ability to make thoughtful recommendations on changes to revenue allocations and rate designs. To avoid basing potentially disruptive and costly policies on fundamentally weak analyses, AECA suggests that a preferable pathway may be to freeze revenue allocations to the agricultural sector

[1] Application 20-07-009.

until PG&E submits data and workpapers that are reasonably accurate, or at least not inconsistent.

In this testimony AECA proposes a number of changes to marginal cost methodologies, in part to reflect the fact that agricultural customers do not cause the costs of or benefit equally from specific system investments and activities when compared with other customer classes. In addition, revenue volatility in the agricultural class has led to average collections that are above forecasted levels; correcting this systematic error requires California Public Utilities Commission (CPUC or Commission) intervention. Finally, agricultural time of use (TOU) rates are protected in state law in a similar manner as residential rates; the Commission must act to enforce legal mandates by requiring PG&E to cap agricultural rates at the system average rate.

1.1. Summary of AECA's Proposals

AECA makes the following proposals to change how PG&E's marginal costs are calculated and revenues allocated to individual customer classes.

1. Agricultural load forecasting must be revised to more accurately represent the dominate role variations in water supply availability play in shaping agricultural load
2. The Commission should adopt the market price benchmarks (MPBs) used to establish the power cost indifference adjustment (PCIA) to determine marginal costs for revenue allocation to be more consistent with other proceedings and transparently reflect marginal costs as reflected in market valuation.
3. Marginal generation energy costs should include the price of renewable energy credits (REC) to meet the renewable portfolio standard (RPS), which is presently omitted from PG&E's calculations, as set in PG&E's ERRA proceeding.

4. Marginal generation capacity costs should be measured by the resource adequacy (RA) MPB set in PG&E's ERRA proceeding.
5. Differences in customer class-specific growth rates should be accurately reflected in marginal cost calculations. Data analysis shows that customer groups' peak and transformer demands measured through the generation and distribution peak cost allocation factors (PCAF) and final load transformer (FLT) loads grow at differing rates than for energy demand. These differences in growth rates should be added to the PCAF and FLT billing demands used to calculate marginal costs.
6. Marginal customer access costs (MCAC) should be calculated by reflecting the opportunity cost of current customers' services[2] which is best represented by the depreciated value of existing services costed at new connections. The MCAC is then calculated by adding this to the proportional share of new services added for the class.
7. For purposes of calculating the MCAC using this method, the agricultural class is forecasted to shrink so the growth rate for the class should be set at zero.
8. PG&E should be ordered to comply with Public Utilities Code Section 744(c) which caps each agricultural time of use average rate at the system average rate.
9. The Commission should protect growers' investments in efficient irrigation systems, which were adopted in part to safeguard the state's water resources. Doing so requires the Commission to recognize the benefits farmers deliver to other customers through their load management investments and allow them to stay on legacy TOU periods

[2] "Opportunity costs represent the potential benefits an individual, investor, or business misses out on when choosing one alternative over another." See Investopedia, https://www.investopedia.com/terms/o/opportunitycost.asp

with similar price ratios between periods, which were the basis for these socially valuable investments.

10. Agricultural customers should be offered account aggregation similar to that provided through virtual net metering.

11. The Commission should require PG&E to closely review its workpapers and various filings to ensure that that they are using consistent data across applications.

Table AECA-1 summarizes AECA's proposed revenue allocation changes before capping and other adjustments as compared to PG&E's proposal. The table below is drawn from PG&E's workpapers as that we could not find the other values in PG&E's workpapers. PG&E shows several different recommendations on increase in in revenue responsibility for agriculture, ranging from 8.4% over a three-year period to 4.5% in a single year from Table 1-1 of PG&E's July Errata testimony,[3] to 4.2% in the revenue allocation workpapers.[4] PG&E's testimony implies that agricultural rates need to rise a full 17% to reach its presumed cost-based allocation—a review of PG&E's previous filed estimates since 1996 show that they have been wrong before. Agricultural rates would be at least 50% higher than today if the Commission had listened to PG&E. AECA instead proposes a series of adjustments to more accurately reflect marginal costs and in the agricultural sales forecast results in a class average decrease of 0.6%.

[3] PG&E, "Overview and Guiding Policy Framework," July 2020 Errata, A.19-11-019, Exhibit (PG&E-1), July 16, 2020, Table 1-1.

[4] See "RA_Rev Alloc_GRC.xlsx", sheet OUT_RA_Result.

Table AECA-1 Proposed Revenue Allocations and Rate Changes

	AECA Proposed Average Rate	PG&E Proposed Rev Alloc Change	AECA Proposed Rev Alloc Change	AECA vs PG&E Avg. Rate Difference
Residential	$0.19676	-1.2%	-2.2%	-1.0%
Small	$0.22918	6.1%	7.2%	1.0%
Medium	$0.17964	-0.2%	-1.7%	-1.5%
E-19	$0.14617	-2.3%	0.1%	2.5%
Streetlights	$0.21838	-4.5%	-3.8%	0.7%
Standby	$0.17518	-3.3%	-1.8%	1.5%
Agriculture	$0.23247	4.2%	-0.6%	-4.8%
E-20 T	$0.09170	-0.1%	0.2%	0.3%
E-20 P	$0.12667	-2.4%	-0.4%	2.0%
E-20 S	$0.14099	-4.5%	-2.6%	2.0%
System	$0.17601	0.0%	0.0%	-0.3%

2. PG&E Agricultural Load Forecast Has a Biased Outcome that Leads to Overcharging Agricultural Customers

Agricultural electricity demand is highly sensitive to water availability. Under "normal" conditions, the State Water Project (SWP) and Central Valley Project (CVP), as well as other surface water supplies, are key sources of irrigation water for many California farmers.[5] Under dry conditions, these water sources can be sharply curtailed, even eliminated, at the same time irrigation requirements are heightened. Farmers then must rely more heavily on groundwater, which requires greater energy to pump than surface water, since groundwater must be lifted from deeper depths.

Over extended droughts, like between 2012 to 2016, groundwater levels decline, and must be pumped from ever deeper depths, requiring even more energy to meet crops' water needs. As a result, even as land is fallowed in response to water scarcity, significantly more energy is required to water remaining crops and livestock. Much less pumping is necessary in

[5] Note that "normal" conditions rarely occur in California where rainfall and snow amounts have been classified as either "wet" or "dry" in 80% of years since 1981. This situation is discussed further below.

years with ample surface water supply, as rivers rise, soils become saturated, and aquifers recharge, raising groundwater levels.

The surface-groundwater dynamic results in significant variations in year-to-year agricultural electricity sales. Yet, PG&E stubbornly assigns the Agricultural class a revenue responsibility based on the assumption that "normal" water conditions will prevail every year, without accounting for how inevitable variations from these circumstances will affect rates and revenues for agricultural and other customers.

This assumption results in an imbalance in revenue collection from the agricultural class that does not correct itself even over long time periods, harming agricultural customers most in drought years, when they can least afford it. Analysis presented in the 2017 PG&E GRC demonstrated that overcollections can be expected to exceed $170 million over two years of typical drought conditions,[6] with the expected overcollection $34 million in a two year period.[7] This collection imbalance also increases rate instability for other customer classes.

2.1. The Bias in PG&E's Forecasting Error Is Significant and Growing

Figure AECA-1 compares the difference between forecasted loads for agriculture and system-wide used to set rates in the annual ERRA Forecast proceedings (and in GRC Phase 2 every three years) and the actual recorded sales for 1995 to 2019. These values were compiled from a series of sources, beginning with AECA and California Farm Bureau Federation (Agricultural Parties) testimony regarding agricultural load forecasting issues filed in PG&E's

[6] Based on average load increases in drought years since 1995.

[7] Based on probability weighted average. A.16-06-013, Testimony of Richard McCann and Laura Norin on Behalf of the Agricultural Parties in Pacific Gas & Electric's (PG&E's) 2017 General Rate Case Phase 2 Application Addressing PG&E's Agricultural Class Balancing Account Study, March 15, 2017, p. 16 (included as Attachment A hereto).

2017 GRC, [8] a PG&E data response provided in the 2020 ERRA Forecast proceeding,[9] and Table 2-3 of the 2021 ERRA Forecast.[10] Notably, the single largest forecasting error for system-wide load was a sales overestimate of 4.5% in 2000 and a shortfall in 2019 of 3.7%, while agricultural mis-forecasts range from an under-forecast of 39.2% in the midst of an extended drought in 2013 to an over-forecast of 18.2% in one of the wettest years on record in 1998. Load volatility in the agricultural sector is extreme in comparison to other customer classes. PG&E has not been able to capture this volatility in its forecasts and has not addressed the significant adverse consequences, particularly to growers, in ratemaking.

[8] A.16-06-013, Testimony of Richard McCann and Laura Norin on Behalf of the Agricultural Parties in Pacific Gas & Electric's (PG&E's) 2017 General Rate Case Phase 2 Application Addressing PG&E's Agricultural Class Balancing Account Study, March 15, 2017, p. 16 (included as Attachment A hereto).

[9] PGE, 2020 ERRA Forecast_DR_CCA_002-Q23Atch01.

[10] PG&E 2020 ERRA Forecast (A.20-07-002) Table 2-3 Workpapers, "02. ERRA 2021-Forecast_WP_PGE_20200717_Ch02_Table 2-3_Sales_rev1_CONF.xlsx," tab "1. Annual Sales," Cell B26.

Figure AECA-1

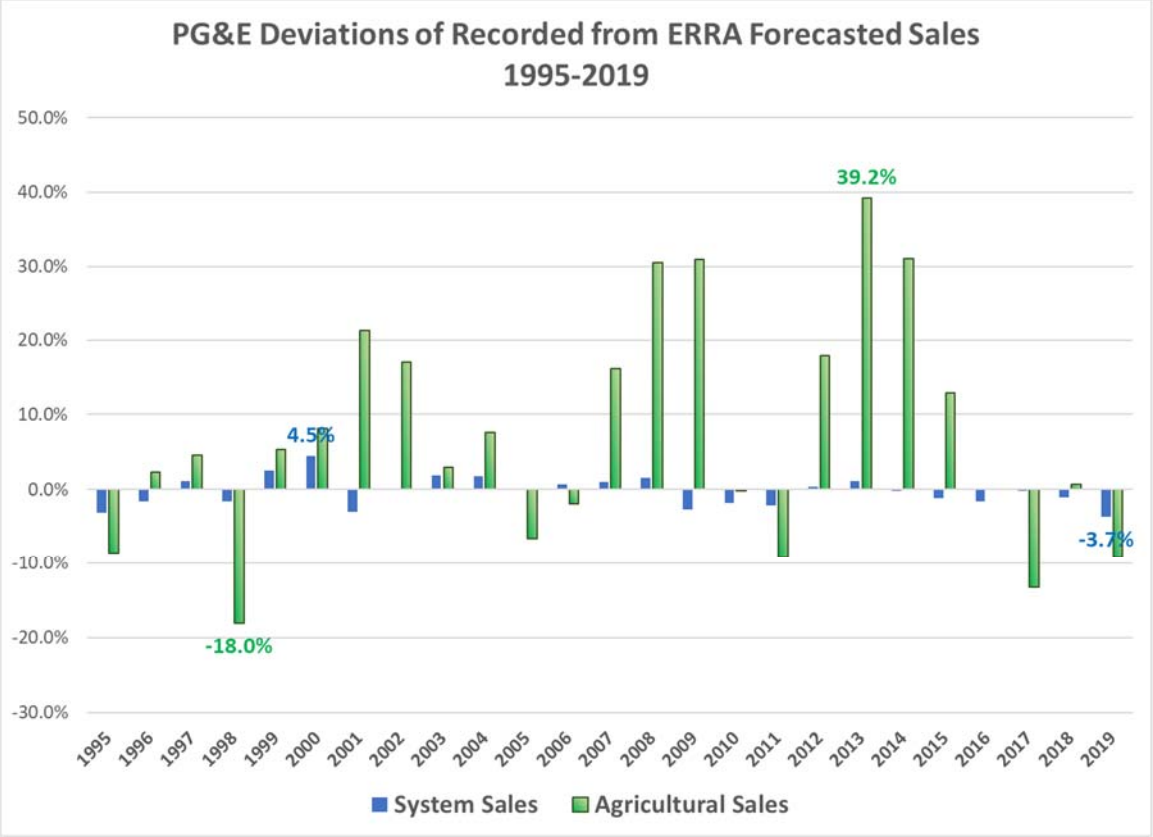
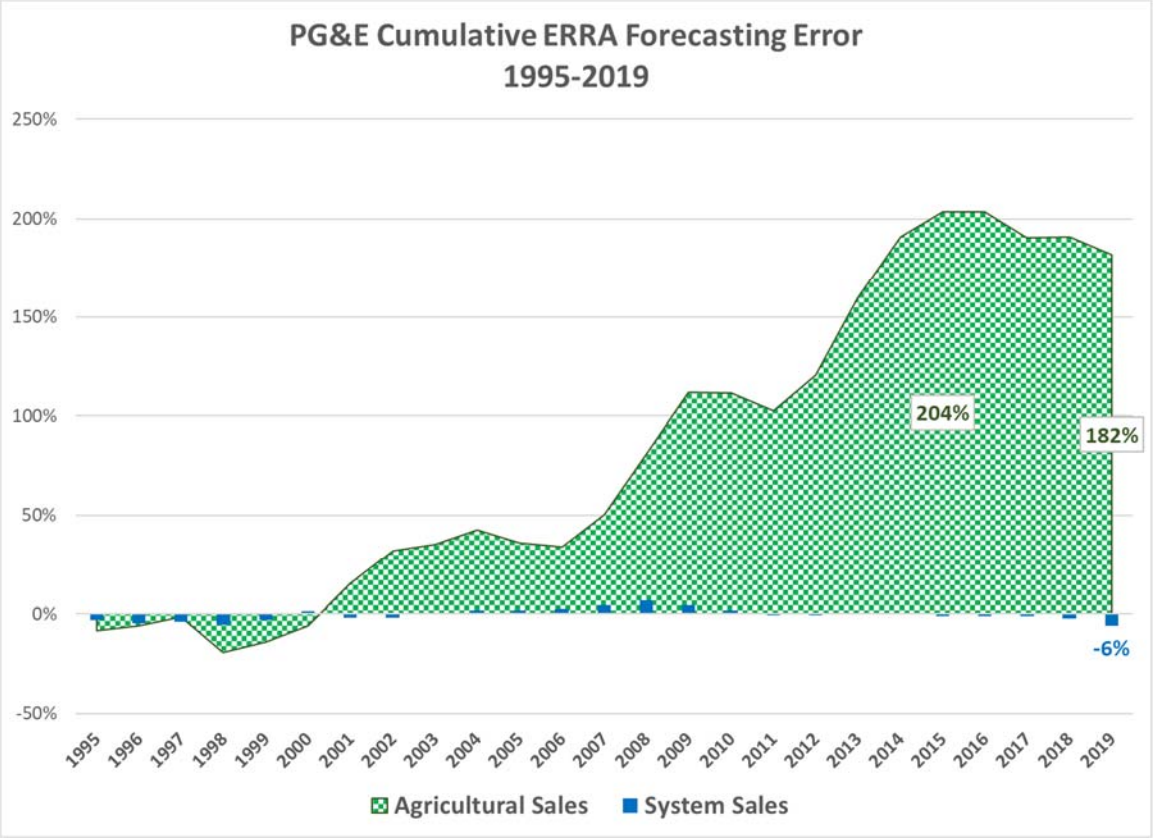


Figure AECA-2 shows the cumulative error caused by inadequate treatment of agricultural load volatility over the last 25 years and the underlying bias in PG&E's forecasting method. An unbiased forecasting approach would reflect a cumulative error of zero over time. The error in PG&E's *system-wide forecast* has largely balanced out, even though the utility's load pattern has shifted from significant growth over the first 10 years to stagnation and even decline. PG&E apparently has been able to adapt its forecasting methods for other classes relatively well over time.

The accumulated error for *agricultural sales forecasting* tells a different story. Over a quarter century the cumulative error reached 182%, nearly twice the annual sales for the Agricultural class. This cumulative error has consequences for the relative share of revenue

collected from agricultural customers compared to other customers, with growers significantly overpaying during the period.

Figure AECA-2



One indication of bias is to measure a forecast accuracy tracking signal. The standard metric for determining if a forecast is correct is if the signal is with a range of between -4.5 and 4.5.[11] PG&E's agricultural forecast over this period shows a tracking signal value of 14.4, far exceeding the standard for bias.

[11] Sujit Singh, "A Critical Look at Measuring and Calculating Forecast Bias," Institute of Business Forecasting & Planning, https://demand-planning.com/2017/01/13/a-critical-look-at-measuring-and-calculating-forecast-bias/, January 13, 2017.

2.2. PG&E's Biased Forecasting Method Has Led to Agricultural Customers Overpaying

Addressing the unique variability and forecasting challenges associated with agricultural sales is critical to establishing just and reasonable rates.[12] Without tackling these issues, there is potential to significantly over- or under-charge agricultural customers relative to their cost of service and to create rate volatility that contributes to a highly unpredictable business environment for the agricultural class.

For example, because ERRA revenues are allocated based on generation revenue allocators adopted in PG&E's GRC Phase 2, most of the total revenue requirements attributable to utility-owned generation assigned to agricultural customers is fixed within the ERRA proceeding. However, if the sales forecast established for the agricultural class is too low (as could happen if actual water availability is less than the water availability reflected in PG&E's sales forecast), generation rates paid by agricultural customers will be set higher than they would have been had an accurate sales forecast been used to fix rates and collect class-specific revenue allocation. The combination of relatively high rates and higher than forecast sales results in over-collection of revenue from the agricultural class compared to its proper revenue responsibility.

There is no mechanism to return such an over-collection to agricultural customers; instead, any spillovers are incorporated into PG&E's ERRA balancing account and returned to all customer classes, of which agricultural constitutes less than 8% of sales.[13] In other words,

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[12] The Agricultural Parties addressed in detail the unique nature of sales variability and sales forecast error for the agricultural customer class compared to other customers classes in testimony submitted in PG&E's 2017 GRC Phase 2. See A.16-06-013, Testimony of Richard McCann and Laura Norin on Behalf of the Agricultural Parties in Pacific Gas & Electric's (PG&E's) 2017 General Rate Case Phase 2 Application Addressing PG&E's Agricultural Class Balancing Account Study, March 15, 2017, pp. 12-16.

[13] As described in PG&E's testimony, "PG&E's ERRA balancing account is used to record PG&E's procurement-related costs and revenues, and any difference flows back to or is collected from customers." PG&E Initial Testimony, July 1, 2020, p. 1-10.

agricultural customers recover less than 8% of their overpayments with the current system. The opposite also occurs, with lower than forecast agricultural sales leading to an under-collection that increases rates for all customers rather than only the agricultural class.

The risk of over- or under-collection of ERRA revenue due to sales being higher or lower than forecast is illustrated in Table AECA-2 below. Table AECA-2 uses data on historic distribution of wet and dry conditions and the corresponding shifts in sales below and above forecasted sales to show how overcollections are typically greater than undercollections and the probability of those overcollections is larger. In this example, the expected overcollection is $86 millions or 8.4% of forecasted annual revenues.

Table AECA-2: Illustrative Agricultural Revenue Given Proposed Bundled Generation Rates and Different Levels of Illustrative Sales[14]

	Sales as Forecast	Sales -9.1% Less than Forecast	Sales 21.1% More than Forecast
Agricultural Average Generation Rate ($/kWh)	$0.10245	$0.10245	$0.10245
Illustrative Annual Agricultural Sales (MWh)	10,000,000	9,087,480	12,105,535
Illustrative Total Annual Revenue ($000s)	$1,024,500	$931,012	$1,240,212
Over /(Under)-collection of Revenue	$0	($93,488)	$215,712
Probability of Occurrence	31.4%	20.0%	48.6%
Pr(Over /(Under)-collection of Revenue)	$0	($18,698)	$104,774
Expected Over /(Under)-collection of Revenue		-1.8%	10.2%

Note that analyses by both PG&E and the Agricultural Parties presented in the 2017 GRC Phase 2 showed that annual variability in agricultural sales is several fold larger than in any other

[14] This example uses illustrative sales to avoid disclosure of confidential PG&E data. It illustrates the impact of sales greater or less than the forecast associated with proposed rates; the precise sales forecast and resulting revenue are not intended to reflect actual PG&E agricultural sales and associated revenue.

rate class, as illustrated in Figure AECA-1 above.[15] This variability in turn has led to substantial errors in PG&E's agricultural load forecast.

Years in which overcollections occur are as much as 40% more likely than for under-collections due to dry years constituting almost half of the years since 1981.[16] Even though both over- and under-collections could theoretically happen due to the difficulty of accurately forecasting agricultural sales, data presented in Figure AECA-2 demonstrates that there is a greater risk of over-collection, to the detriment of agricultural customers, as compared to under-collection, which would benefit the agricultural class.[17]

That is, the potential rate impacts of inaccurate sales forecasts are not likely to balance out over time due to a mix of years in which sales forecasts are too high or too low. This is illustrated by the water year type for the Sacramento Valley Unimpaired River Runoff Water Year Index data, as defined by the California Department of Water Resources (DWR) for the years 1981 through 2018, shown in Table AECA-3 below. The weighted average of the example in Table AECA-2 is a net $86 million in overcollections due to differences in probabilities of wet versus dry years.[18] In other words, the forecasting error bias in PG&E's data is not just from flaws in PG&E's econometric equations, but rather in the underlying assumption about the probability of the key driver in agricultural sales—water availability for growing crops.

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[15] A.16-06-013, Testimony of Richard McCann and Laura Norin on Behalf of the Agricultural Parties in Pacific Gas & Electric's (PG&E's) 2017 General Rate Case Phase 2 Application Addressing PG&E's Agricultural Class Balancing Account Study, March 15, 2017, p. 13.

[16] California Department of Water Resources, California Data Exchange Center, "Chronological Reconstructed Sacramento and San Joaquin Valley Water Year Hydrologic Classification Indices," https://cdec.water.ca.gov/reportapp/javareports?name=WSIHIST

[17] A.16-06-013, Testimony of Richard McCann and Laura Norin on Behalf of the Agricultural Parties in Pacific Gas & Electric's (PG&E's) 2017 General Rate Case Phase 2 Application Addressing PG&E's Agricultural Class Balancing Account Study, March 15, 2017, pp. 27-29.

[18] Note that the average increase in dry year sales is larger than the average decrease in wet years, so that the actual over-collection is larger than shown in this example.

Table AECA-3: Historic Water Year Conditions, DWR Sacramento Valley Unimpaired Runoff Water Year Index Type, 1981-2018[19]

	Percent of Total Years
Wet	31.4%
Above Normal or Below Normal	20.%
Dry or Critically Dry	48.6%

In its 2017 Agricultural Class Balancing Account Study, PG&E claimed without evidence that the marginal costs to serve customers rose as the added revenues.[20] But analysis of PG&E's workpapers reveals that marginal costs are half or less of revenues. In Chapter 9 of PG&E's 2021 ERRA Forecast Testimony, the utility shows that the market value or opportunity cost of its generation portfolio is about 46% of total portfolio costs.[21] Since market value in this context represents marginal cost, the economic interpretation is that a variation in agricultural sales will cause costs to change by only 46% of the change in revenues.[22] In other words, a 10% increase in agricultural sales will lead to a 5.4% increase in net revenues after accounting for costs to PG&E's ERRA account. Distribution marginal costs follow a similar pattern, with the PCAF as one marginal cost metric rising only at 60% of the energy demand increase; net revenues increase 4% with a 10% rise in agricultural load.[23] The FLT demand is invariant with

[19] California Department of Water Resources. Chronological Reconstructed Sacramento and San Joaquin Valley Water Year Hydrologic Classification Indices. Accessed on August 20, 2019 via http://cdec.water.ca.gov/reportapp/javareports?name=WSIHIST.

[20] PG&E, *Pacific Gas and Electric Company's (PG&E) Agricultural Balancing Account Study with Agricultural Parties' Addendum*, Final Report, September 30, 2016.

[21] PG&E, ERRA Forecast Testimony, July 1, 2020, A.20-07-009, Chapter 9.

[22] See PG&E 2021 ERRA Forecast Initial Testimony, July 1, 2020, Table 9-3, comparing the sums of Lines 28 and 29.

[23] Analysis based on compiled data responses:
GRC-2017-PhII_DR_CFBF_005-Q01.pdf
GRC-2017-PhII_DR_CFBF_006-Q01.pdf
GRC-2017-PhII_DR_CFBF_006-Q02.pdf
GRC-2017-PhII_AGParties_DataReporting_PartC.PDF
GRC-2017-PhII_AGParties_DataReporting_PartC-SUPP01.pdf
GRC-2017-PhII_DR_AGParties_DataRep_2016-A-Q01_B-Q01.pdf
GRC-2017-PhII_DR_AGParties_DataRep_2016-A-Q04_B-Q04 (01057285xB0262).pdf
GRC-2017-PhII_DR_AGParties_DataRep_2016-A-Q04_B-Q04.pdf

increased energy demand and only rises with additional customer accounts. Accounts change less than 0.2% with variations in water conditions, so almost 100% of secondary distribution revenue is above marginal costs. Because agricultural sales are not balancing out between under- and over-forecasted levels, these net overpayments have been accumulating, and will continue to accumulate until this problem is addressed.

It is important to acknowledge that if actual agricultural sales are substantially lower or higher than forecast, implications extend beyond over- and under-collections from the agricultural customer class. For example, significantly higher than forecast sales occurring in a low surface water availability year may impose incremental generation capacity and/or energy costs on the system beyond those reflected in the allocation of generation revenue to each customer class.[24] As a result, adjusting agricultural rates to account for deviations from year-ahead sales forecasts may require an accounting of incremental system costs as well as changes in sales to the agricultural customers. A solution addressing the nuances associated with agricultural sales forecasting, therefore, is too complex to be tackled within the context of the annual ERRA forecast proceedings and the Commission ordered that these issues be addressed in this GRC.

GRC-2017-PhII_DR_AGParties_DataRep_2017-A-Q01_B-Q01.pdf
GRC-2017-PhII_DR_AGParties_DataRep_2017-A-Q04_B-Q04 (01057278xB0262).pdf
GRC-2017-PhII_DR_AGParties_DataRep_2017-A-Q04_B-Q04.pdf
GRC-2017-PhII_DR_AGParties_DataRep_2017-A-Q04j-SUPP01.pdf
GRC-2017-PhII_DR_AGParties_DataRep_2018-A-Q01_B-Q01.pdf
GRC-2017-PhII_DR_AGParties_DataRep_2018-A-Q04_B-Q04.pdf
GRC-2017-PhII_DR_AGParties_DataRep_2018-A-Q04j_B-Q04de_SUPP01.pdf
GRC-2017-PhII_DR_AGParties_DataRep_2019-A-Q01_B-Q01.pdf
GRC-2017-PhII_DR_AGParties_DataRep_2019-A-Q04_B-Q04.pdf
GRC-2017-PhII_DR_AGParties_DataRep_2019-A-Q04j_B-Q04de_SUPP01.pdf

[24] As discussed in PG&E's ERRA testimony, incremental generation revenue authorized in the ERRA proceeding is allocated using an equal percentage of functional revenue per D.18-08-013 (PG&E Initial Testimony, July 1, 2020, p. 19-3), which effectively means that rate changes resulting from incremental generation revenue requirements in the ERRA proceeding maintain the generation revenue allocation for each customer class authorized in the most recent GRC Phase 2 proceeding.

2.3. Proposed Fixes Can Address in Part PG&E's Biased Forecast Error

Agricultural load forecasting should be revised to better address how variations in water supply availability drive agricultural load. Most importantly, the final forecast should be constructed from a weighted average of forecasted loads under normal, wet and dry conditions. The forecast of agricultural accounts also must be revamped to include these elements—PG&E's current forecast method appears to be a simplistic trend analysis that ignores the influence of outside factors, such as those listed below. In addition, the load forecast should include the influence of rates and a publicly available data source on agricultural income that differs from the one PG&E currently uses. Further, PG&E appears to be relying on a data set of agricultural economic activity that does not match publicly available data from the U.S. Department of Agriculture.[25]

The Agricultural Parties have met with PG&E staff and submitted testimony in several cases, including the 2017 GRC Phase 2 and the last two year's ERRA Forecast proceedings, suggesting ways in which forecasting can be improved. While PG&E has made several adaptations, its current method still does not reflect a sufficient understanding of what drives agricultural sales variations year to year and growth over time. AECA proposes that PG&E return to the drawing board and approve the new agricultural load forecast method proposed by AECA that reflects the changes suggested here.

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[25] As one further point, PG&E inflates its model's statistical precision by using monthly, instead of annual, data. As discussed, agricultural electricity use is a function of annual, not monthly, conditions. PG&E divides a set of annual physical indicators, such as water availability and crop production income, that occurs once a year into 12 monthly values, and then claims that it has 12 times as many "independent" variables. Twelve values that sum up to a single value cannot be independently distributed from each other as random variables —an increase in one must dictate a decrease in another. PG&E's approach violates a key principle of econometric theory. (See George G. Judge, et al., *Introduction to the Theory and Practice of Econometrics*, Second Edition, John Wiley & Sons, 1988, p. 160.) PG&E can use other methods to derive monthly sales values; the current method falsely reports better model performance than is valid.

2.3.1. PG&E's Model Can Use An Additional Drought Indicator and Forecasted Agricultural Rates to Improve Its Forecast Accuracy

As described in PG&E's 2021 ERRA Forecast testimony, "[a]gricultural class sales to all retail customers (including PG&E bundled, CCA and DA) are closely tied to available water in the service territory, since farmers pump groundwater for irrigation needs."[26] Although PG&E discusses annual agricultural electricity sales in relation to precipitation,[27] the more direct relationship to determine agricultural class energy needs is between the allocation of surface water via state and federal water projects and the need to pump groundwater when adequate surface water is not available from the SWP[28] and federal CVP.[29] The SWP and CVP are critical to California agriculture because little precipitation falls during the state's Mediterranean-climate summer and snow-melt runoff must be stored and delivered via aqueducts and canals. Surface water availability, therefore, is the primary determinant of agricultural energy use, while precipitation and related factors, such as drought, are secondary causes in that they are only partially responsible for surface water availability. Other factors such as state and federal fishery protections substantially restrict water availability and project pumping operations greatly limiting surface water deliveries to San Joaquin Valley farms.

PG&E has never reported an analysis of this energy-water interaction, including testing whether a relationship exists between either its rainfall data or the Palmer Drought Stress Index

[26] PG&E Initial Testimony, 2021 ERRA Forecast, A.20-07-002, July 1, 2020, p. 2-7.
[27] PG&E Initial Testimony, 2021 ERRA Forecast, A.20-07-002, July 1, 2020, p. 2-7.
[28] The California Department of Water Resources operates the SWP, which deliveries to many agricultural customers in Northern California and the southern San Joaquin Valley. See the State Water Project website at https://water.ca.gov/Programs/State-Water-Project.
[29] The U.S. Bureau of Reclamation CVP serves many agricultural customers and similarly must manage surface water resources. See, for example, the CVP website at https://www.usbr.gov/mp/cvp/about-cvp.html. The amount of water delivered to agricultural customers via the CVP is larger than through the SWP.

(PDSI), which the utility currently uses, and the water project deliveries that are the fundamental driver of variations in agricultural water pumping in California.[30]

AECA found that the PDSI is highly correlated with contract allocations for deliveries through the SWP and CVP,[31] reaching 0.78 for both of them,[32] as shown in Figure AECA-3. Of even greater interest and relevance to PG&E's forecasting approach, the correlation with the previous year's PDSI and project water deliveries is almost as strong, 0.56 for the SWP and 0.53 for the CVP. This relationship can be seen also in Figure AECA-3, as the PDSI line appears to lead changes in the project water deliveries. This strong relationship with this lagged indicator is not surprising, as both the California Department of Water Resources and U.S. Bureau of Reclamation account for remaining storage and streamflow that is a function of soil moisture and aquifers in the Sierras. PG&E is using the right indicator in the PDSI but not using it to the full extent of its explanatory power for agricultural energy use.

These relationships provide a means for PG&E to update its forecast in November using actual rather than just hypothetical hydrologic data by adding the lagged PDSI variable in its regression model.[33] In other words, PG&E can improve its forecasting in real time by using an additional data series that strongly forecasts the most important driver in year-to-year variation in agricultural sales. In this manner, PG&E can reduce the likelihood of under- or overforecasting sales with concomitant under or overcollection of revenues from the agricultural class.

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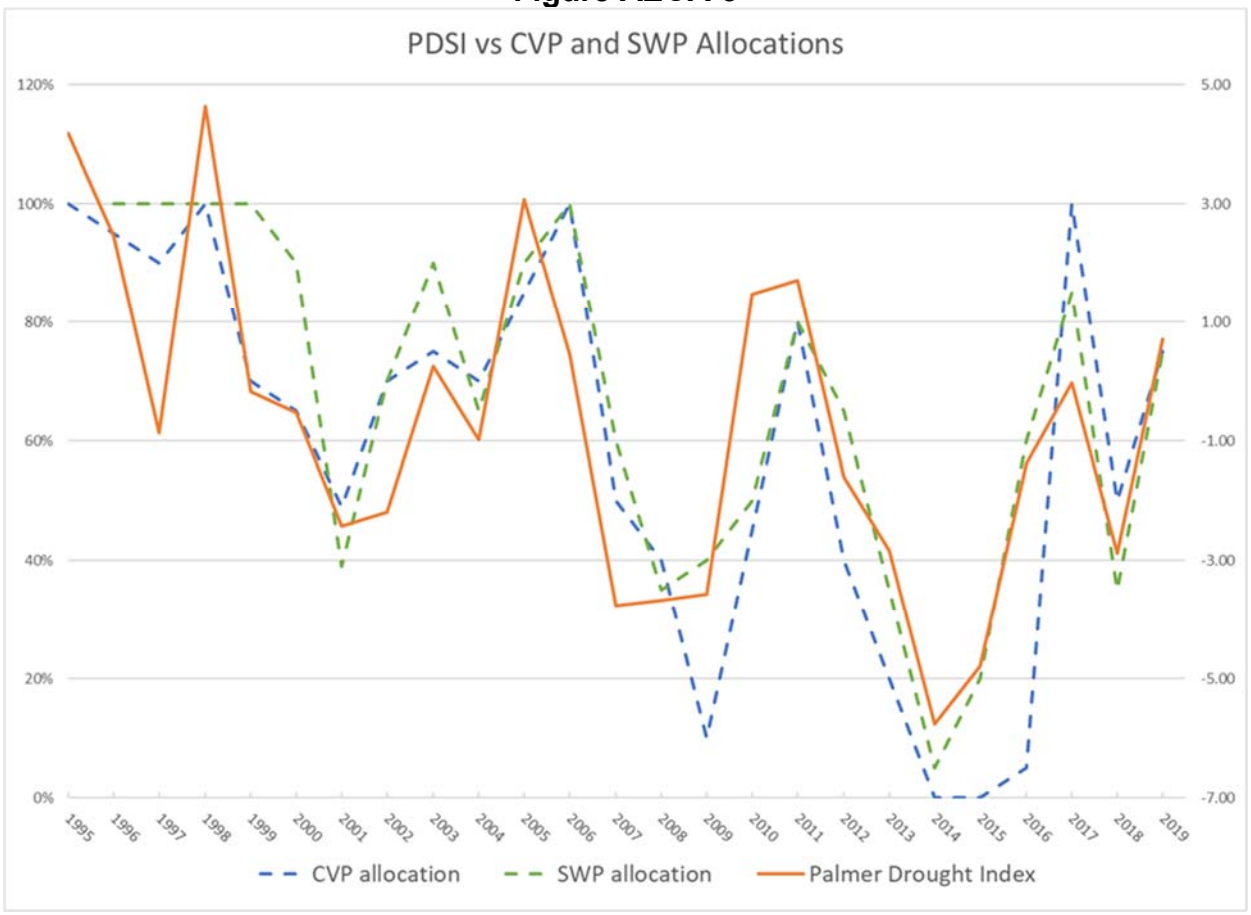
[30] AECA has repeatedly provided PG&E with data sources that report annual water system deliveries for the SWP and CVP.

[31] Both projects announce, in the spring of each year near the beginning of the growing season, the percentage of the total amount of contracted water amounts that will be delivered during the remainder of the year. In very wet years, this can reach 100% of contracted amount, and has fallen to 0% in 2014 and 2015.

[32] A correlation factor or R-squared ranges from 1 to -1, with 1 representing perfect correlation, -1 perfectly negatively correlated, and 0 is completely uncorrelated. These values show strong correlation.

[33] Note that the correlation between the current and lagged PDSI is only 0.34, which indicates that both variables can be included in the regression model.

Figure AECA-3

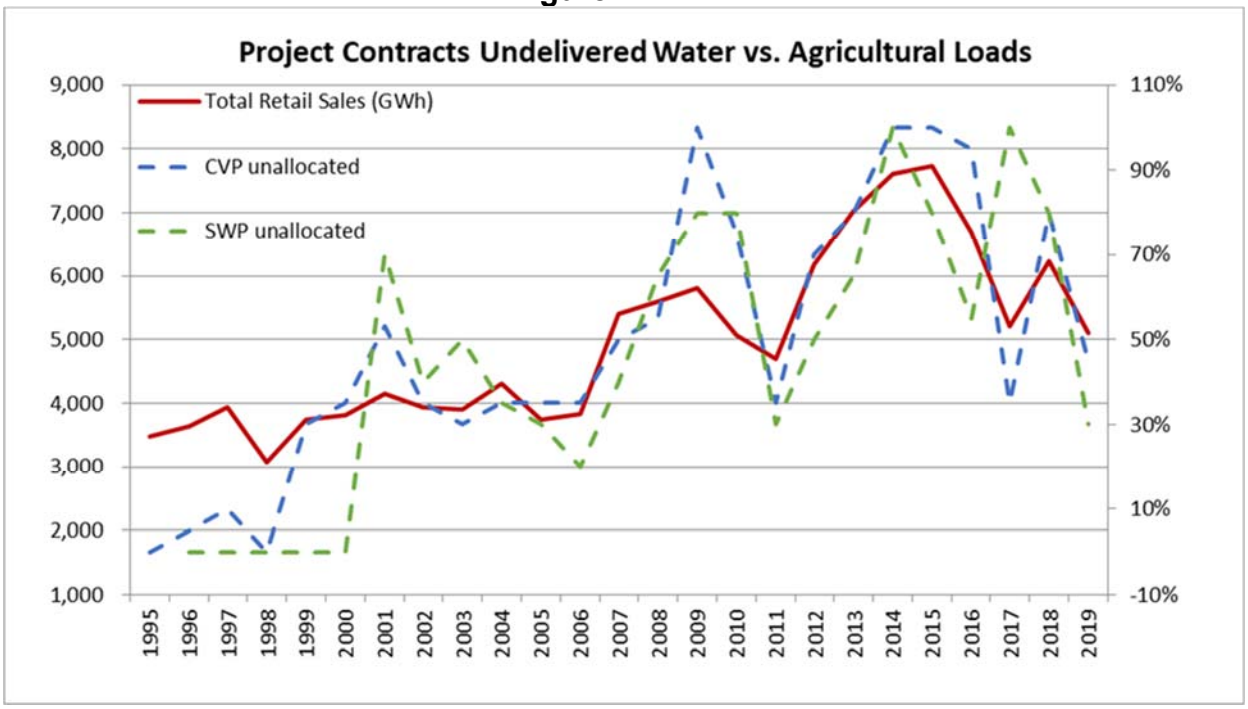


Further, comparing the inverse of water delivery allocations, (i.e., the undelivered contract shares), to the annual agricultural sales, we can see how agricultural load has risen since 1995 as the contract allocations delivered have fallen (i.e., the undelivered amount has risen) as shown in Figure AECA-4. The decline in the contract allocations is only partially related to the amount of precipitation and runoff available. In 2017, which was among the wettest years on record, SWP Contractors[34] only received 85% of their allocations, while the SWP provided 100% every year from 1996 to 1999. The CVP has reached a 100% allocation only once since 2006, while it regularly delivered above 90% prior to 2000. The reductions in deliveries is a

[34] The SWP sells directly to local water agencies who then distribute water to growers and other customers.

result of changing regulations by state and federal agencies in the Bay-Delta that limit amounts that can be pumped by the projects. Changes in contract allocations dictated by regulatory actions are clearly a strong driver in the growth of agricultural loads. The combination of the forecasted PDSI and the lagged PDSI of the just concluded water year can be used to capture this relationship.

Figure AECA-4



Again, this is an element that can add current information to PG&E's forecast in its November Update. Since the lagged PDSI is able to predict in part the likely project deliveries in the coming year (e.g., the 2020 PDSI influences the 2021 project deliveries), PG&E can use this relationship to forecast more accurately the contract delivery allocations for the coming year in the ERRA Forecast application, as well as in its GRC applications, and how that will affect growth in agricultural sales.

Finally, as pointed out in Table AECA-3, a "normal" water year rarely occurs. Over time, the best representation of both surface water availability and the electrical load dependent on it is

a weighted average across the probabilities of different water year conditions. Table AECA-3 provides the weights for each of those water condition classifications. PG&E should develop three different forecasts that use the averages of water conditions for wet, above and below normal, and dry years, and then combine the forecasts into a single forecast for the coming year. This approach would be a key step in eliminating the forecast bias that is obvious in Figure AECA-2.

2.3.2.PG&E's Data on Agricultural Economic Activity Does Not Match Either Published Data or Data Available from Its Vendor

PG&E states that it uses monthly agricultural economic income data provided by its vendor, Moody's Analytics as one driver in its agricultural load forecast. AECA acquired data on statewide agricultural economic activity from the U.S. Department of Agriculture Economic Research Service (USDA ERS)[35] and compared this information to what is shown in PG&E's workpapers.[36] PG&E indicates that its data represents only its service territory, but the counties served by the utility produce about 66% of the state's agricultural output, and the counties' output varies in close parallel to statewide data, which should is not surprising as state agriculture is dominated by the PG&E service area. Figure AECA-5 shows the relationship of statewide agricultural output to the counties served by PG&E, and the statewide agricultural value added. Moody represents that it draws its data from the USDA ERS source, but that cannot be said for the data that PG&E is using.[37] The quantitative comparison calls into question that

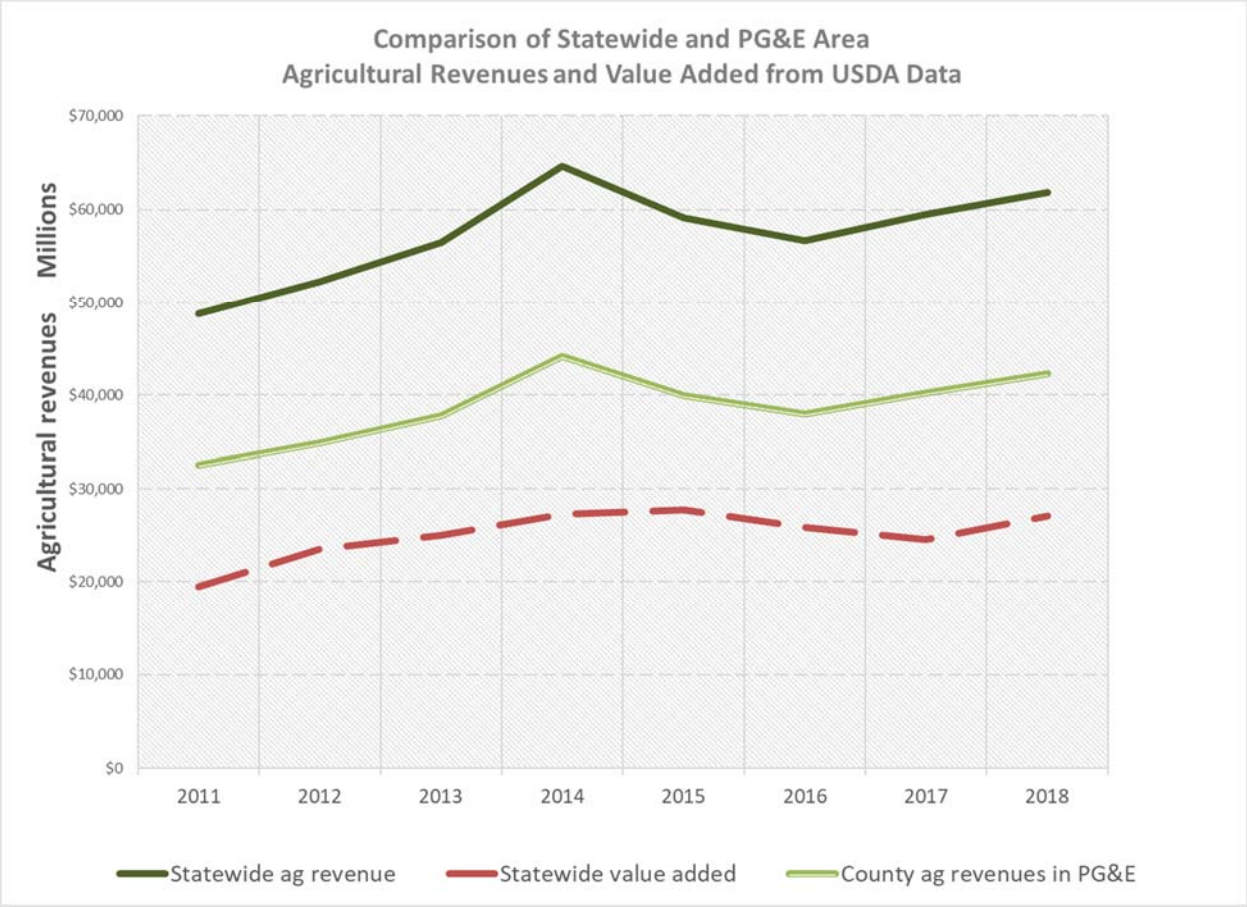
[35] United States Department of Agriculture Economic Research Service. Net Cash Income—All Commodity receipts. https://data.ers.usda.gov/reports.aspx?ID=17831, and USDA ERA, "Data Files: U.S. and State-Level Farm Income and Wealth Statistics," https://www.ers.usda.gov/data-products/farm-income-and-wealth-statistics/data-files-us-and-state-level-farm-income-and-wealth-statistics/.

[36] 2021 ERRA Forecast Table 2-3 Workpapers, "02. ERRA 2021-Forecast_WP_PGE_20200717_Ch02_Table 2-3_Sales_rev1_CONF.xlsx," tab "18. Ag_kwh_data," Column Q.

[37] ERRA 2021 PG&E Forecast DR AgParties 001-Q06 and AgParties 001-Q07.

assertion. The data included in PG&E's figures has a correlation of only 0.65 (with 1.0 being perfect) with the value-added data reported by USDA.

Figure AECA-5

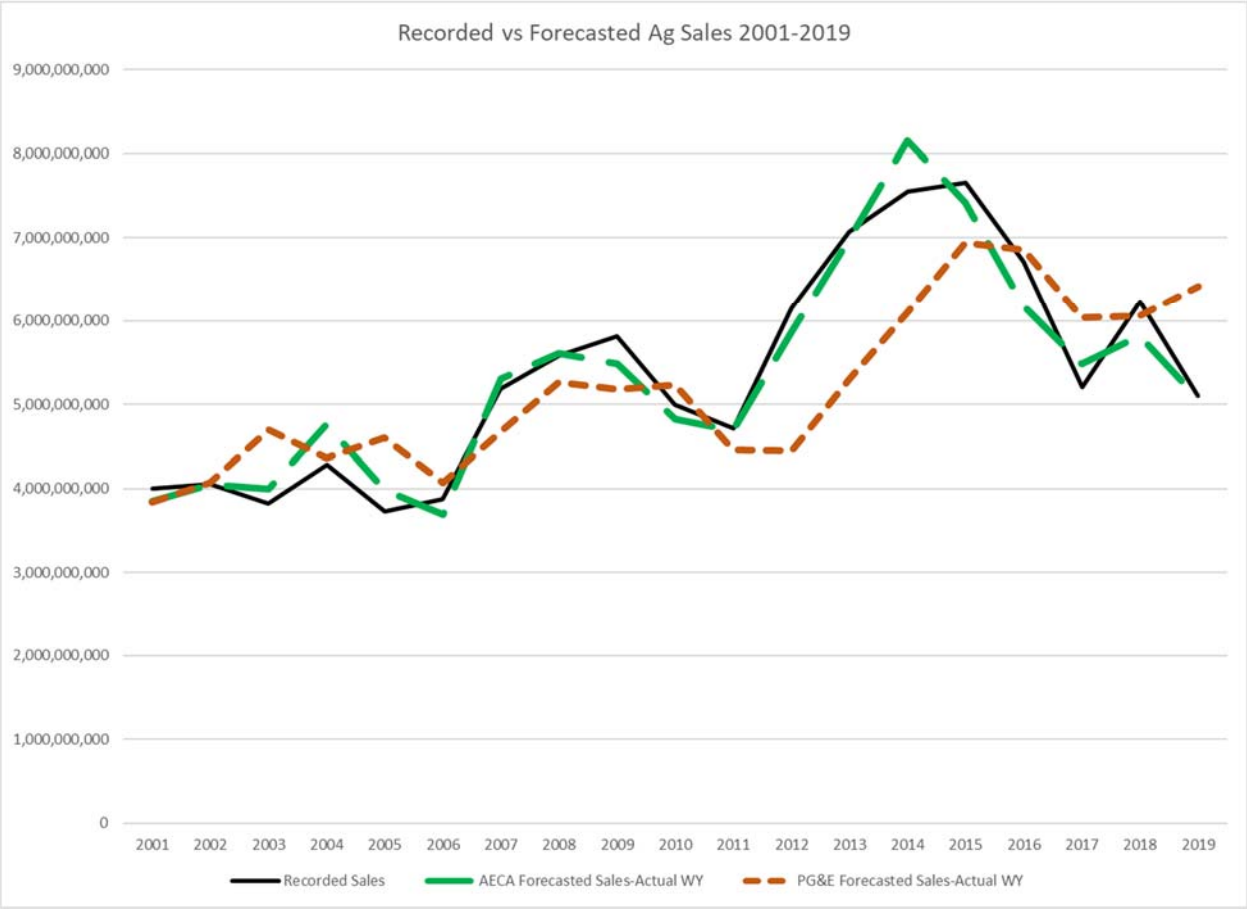


2.3.3.Proposed Revised Agricultural Forecast

AECA prepared a new agricultural load forecast for 2021 implementing the changes recommended herein. In addition, the forecasted average agricultural rate was added, which was revealed to be statistically valid. Forecasts of total class sales (rather than a forecast of average use per customer as PG&E does) and changes in agricultural accounts were prepared. The account forecast was developed using most of the same variables as for the sales forecast to reflect similarities in drivers of both sales and accounts. PG&E's current accounts forecasting model is a trending model unresponsive to changes in economic and water supply conditions.

Figure AECA- 6 compares the performance of AECA's proposed model to PG&E's current model. The backcasted values from the AECA model have a correlation coefficient of 0.973 with recorded values,[38] while PG&E's sales forecast methodology only has a correlation of 0.742.[39] Unlike PG&E's model almost all of the parameter estimates are statistically valid at the 99% confidence interval, with only summer and fall rainfall being insignificant.[40]

Figure AECA-6 Comparison of AECA and PG&E Sales Backcast with Recorded Data



[38] A correlation of 1.0 is perfect.

[39] PG&E Data Response, ERRA-2021-PGE-Forecast_DR_AECA_002-Q02Atch01.xlsx.

[40] The insignificance of summer and fall rainfall is expected because so little falls then in California. With irrigated agriculture winter and spring rains drive water availability.

AECA's accounts forecast model reflects similar performance, with a correlation of 0.976. The backcast and recorded data are compared in Figure AECA-7. Table AECA-4 shows the parameter values for the monthly sales forecast model. Table AECA-5 shows parameter values for the monthly accounts forecast model.

Figure AECA-7 Comparison of AECA Accounts Forecast with Recorded Data

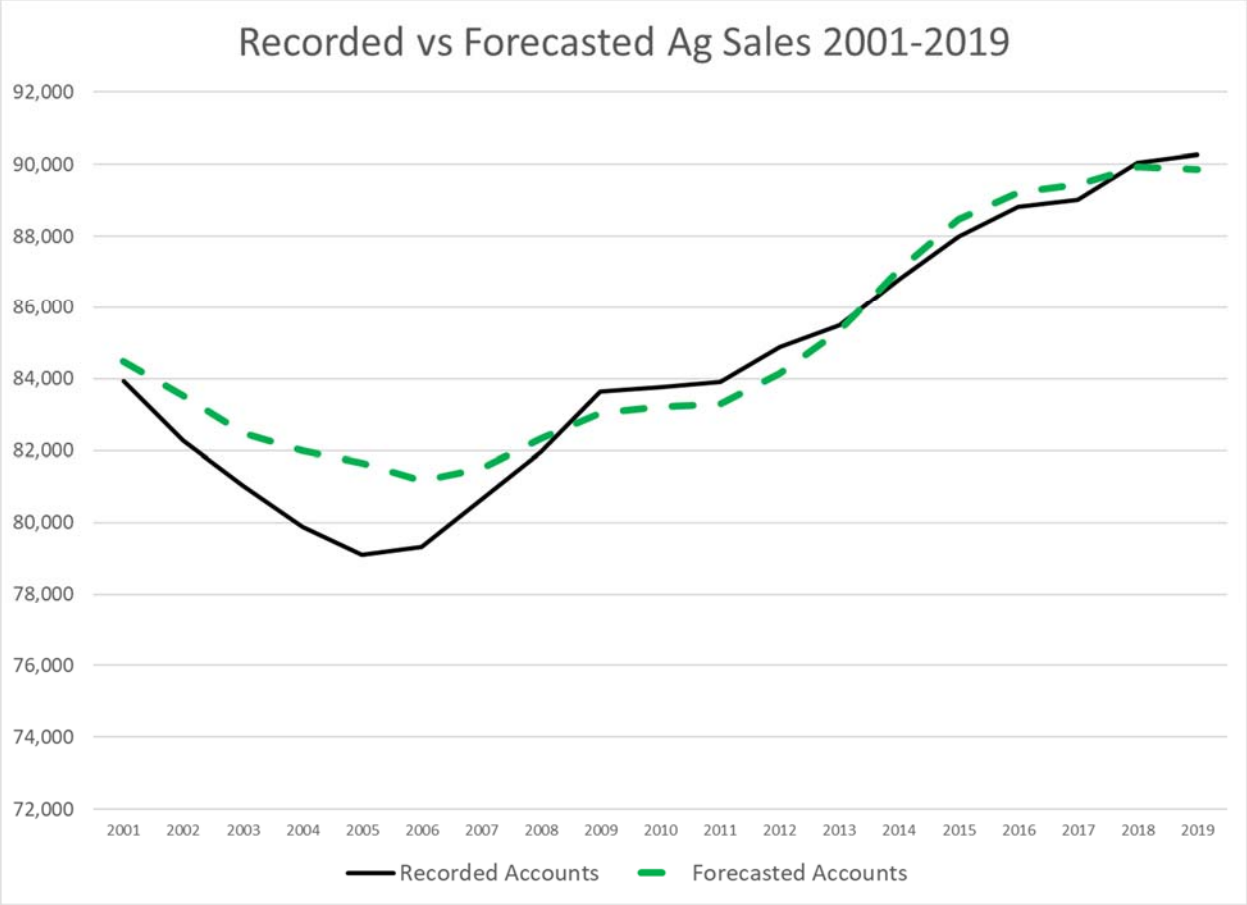


Table AECA-4 Agricultural Sales Forecast Monthly Model Parameters

Multiple R	0.984796			
R Square	0.969824			
Adjusted R Square	0.96581			
Standard Error	0.098526			
Observations	231			
	df	SS	MS	F
Regression	27	63.33199	2.345629	241.6348249
Residual	203	1.970588	0.009707	
Total	230	65.30258		
	coeff	std err	t stat	p-value
Intercept	18.0055	0.104104	172.9576	2.2914E-222
PDSI_new	-0.026673	0.003947	-6.758169	1.44962E-10
PDSI_lagged	-0.023631	0.003173	-7.448337	2.65629E-12
AG_VA_USDA	3.08E-08	1.36E-09	22.57496	2.91626E-57
LN_AG_PRICES	-0.273631	0.043148	-6.341608	1.44875E-09
RAIN01	0.002164	0.012118	0.178576	0.858449107
RAIN02	-0.004503	0.010861	-0.414605	0.678869086
RAIN03	-0.005494	0.005097	-1.077842	0.282383533
RAIN04	-0.010217	0.003909	-2.613986	0.009619933
RAIN05	-0.014331	0.003508	-4.084776	6.34801E-05
RAIN06	-0.012604	0.002932	-4.298977	2.66277E-05
RAIN07	-0.011138	0.002748	-4.05308	7.19837E-05
RAIN08	-0.009119	0.002625	-3.47364	0.000627532
RAIN09	-0.004175	0.002585	-1.615071	0.107848486
RAIN10	-0.000214	0.002582	-0.082987	0.933943654
RAIN11	0.000517	0.002557	0.202371	0.839828987
RAIN12	-0.00176	0.00252	-0.698512	0.485656399
month2	0.256532	0.090348	2.839366	0.004980131
month3	0.482577	0.092129	5.238079	4.04572E-07
month4	0.833096	0.093829	8.878911	3.59213E-16
month5	1.164431	0.094037	12.38271	1.33556E-26
month6	1.235776	0.093459	13.22272	3.36216E-29
month7	1.205268	0.093661	12.86841	4.21511E-28
month8	1.094848	0.093711	11.6832	1.87672E-24
month9	0.939866	0.09444	9.951941	2.94906E-19
month10	0.625932	0.069175	9.048518	1.19297E-16
month11	0.251225	0.078745	3.190349	0.001646471
month12	-0.076547	0.079695	-0.96051	0.337941422
AR(1)	0.582982	0.053631	10.8702	1.90177E-22

Table AECA-5 Agricultural Accounts Forecast Monthly Model Parameters

Multiple R	**0.860602**		AIC	2375.435
R Square	0.740636		AICc	2378.205
Adjusted R Square	0.72319		SBC	2431.059
Standard Error	139.3837			
Observations	239			
ANOVA				Alpha
	df	SS	MS	F
Regression	15	12371551	824770.1	42.45308
Residual	223	4332400	19427.8	
Total	238	16703951		
	coeff	std err	t stat	p-value
Intercept	-752.996	122.9293	-6.12544	4.04E-09
PDSI_new	-13.4347	3.75637	-3.57651	0.000427
PDSI_lagged	1.794386	4.342714	0.413195	0.679861
AG_VA_USDA	7.08E-06	1.84E-06	3.846464	0.000156
LN_AG_PRICES	-206.79	59.99068	-3.44704	0.000677
month2	174.4338	44.66717	3.90519	0.000125
month3	387.3594	44.79732	8.646933	1.05E-15
month4	517.0653	44.71686	11.56309	1.55E-24
month5	584.1291	46.49491	12.56329	9.99E-28
month6	382.5104	46.54293	8.218442	1.68E-14
month7	289.2088	46.26463	6.251187	2.05E-09
month8	230.7293	46.68316	4.942452	1.52E-06
month9	152.7674	47.68393	3.203751	0.001555
month10	119.8028	48.55693	2.467265	0.014368
month11	-63.4957	44.77065	-1.41824	0.157515
month12	-172.311	44.68358	-3.85625	0.000151
AR(1)	0.267934	0.06365	4.209511	3.64E-05

2.3.4.Recommendations

This testimony demonstrates that PG&E's agricultural load forecasting method is materially flawed in several ways. The utility's approach has led to a biased forecast that has resulted in a substantial overcollection of revenues from agricultural customers over the last 25 years. To correct this, the Commission should order PG&E to do the following, beginning with the November Update in this proceeding:

1. Revise its forecasting model to incorporate the lagged PDSI from the current year to forecast next year's agricultural load.
2. Update its forecasting model to incorporate the changing relationship of CVP and SWP contract allocations for water deliveries with hydrologic conditions as measured by the PDSI.
3. Prepare three forecasts using assumptions appropriate for wet, above and below normal, and dry conditions and prepare final forecasts as a weighted average of these forecasts.
4. Replace the current data series on agricultural economic activity (purportedly Moody's Analytics) with USDA ERS data or actual data acquired from a vendor. If the latter, the data must be provided to intervenors to verify the information source and reconcile it with USDA ERS data.
5. Further review both PG&E's forecasting methods and development of an alternative rate setting mechanism, such as a balancing account or a springtime rate adjustment, that accounts for the volatility in agricultural loads driven by changes in water availability and resulting miscollection of revenues.

3. Marginal Costs

Various proposals have been submitted to the Commission in GRCs over the years by the California Public Advocates Office and its predecessors, TURN and even PG&E that purport to calculate marginal costs that reflect the differences in cost causality created by variations in customer class growth rates. A customer class that is growing rapidly intuitively adds more cost burdens than one that is shrinking and whose needs can be met easily with the existing system. To date, the methods that have been proposed are either unsatisfactory to proceeding participants and the Commission or do not properly capture the effects of growth.

How to implement economically-efficient methods of pricing different components of the electricity supply network have become muddled over the years, in part because what looked to be an easy, transparent task has turned out to be both much more complex than originally envisioned and to be politically fraught with undesirable consequences. The Commission now relies on a legacy system built over time that reflects a patchwork of approaches that obscure true cost causality, and omit almost entirely the emergence of new technologies that are, or should be, fundamentally altering the grid.

The Commission recognized more than two decades ago that differences in class-specific growth rates and delivered reliability should be accounted for in marginal costs. However, applying those concepts has not been straightforward, and resulted in significant distortions from true marginal cost-based revenue responsibility allocations as AECA has shown in GRC testimony over the last quarter century. While the Commission issued several decisions in the mid-1990s related to how to properly estimate marginal costs for different expenditure bundles, more recent information and utility changes, such as advanced metering technology, varying definitions of boundaries between system components and responsibilities (*e.g.*, distribution versus customer services, and customer versus utility resources), and the rise of customer-side distributed resources, has eroded the reliability of existing approaches to capture these costs.

AECA has identified in previous GRCs alternative methods for calculating marginal costs for revenue allocation purposes that are consistent with the Commission's objectives of properly accounting for changing reliability, the timing of resource additions, and assigning cost causality to customer classes. These methods measure the cost impact of growth in a consistent and intuitive manner, which we call "growth-based marginal costs" (GBMC). The approach begins with the principle of the replacement cost new, less depreciation (RCNLD) calculation

that recognizes that new investment is deferred by the remaining life of the existing infrastructure.[41] At the core of each calculation is the principle that faster growth accelerates the need for new resources. The value of that acceleration can be measured using the time value of money (or the discount rate) to calculate how resource costs increase when it is needed sooner. Assuming a 10% discount rate, if a resource is acquired one year earlier, its cost increases by 10%. If that resource acquisition is deferred by one year, its cost decreases by 10%.

3.1. Marginal Generation Costs Should Rely on Consistent Benchmarks Across Rate Proceedings, So PG&E Should Use the Market Price Benchmarks from the ERRA Forecast

3.1.1. Marginal Energy Cost Should Include the RPS Adder Since at Least 33% of New Generation Must Be Green

The RPS has added another dimension that should be incorporated in the MEC calculation. For each additional kilowatt-hour of energy, at least 33% must come from a renewable resource, not natural gas.[42] Thus, the standard method for calculating the MEC covers only 67% (at most) of the cost; at least 33% of the remainder is to be derived from the energy-related component cost of renewables' power purchase agreements (PPAs).

The REC market price benchmark (MPB) is $17.35 per megawatt-hour based on the 2020 November Update filed by the Energy Division and should be applied to the marginal energy cost.

3.1.2. Marginal Generation Capacity Cost Should Be Based on the Resource Adequacy MPB Since the Marginal Resource Cannot Be Clearly Identified

The Commission should adopt the MPBs used to establish the PCIA to determine marginal costs for revenue allocation. Accepting this approach has two advantages. First, the

[41] For a definition see https://www.readyratios.com/reference/appraisal/cost_approach_to_value.html

[42] Given that the final RPS target is 33% and PG&E is still below that level, the required increment is larger than 33%. The steady-state requirement will increase from 33% after 2020 to 60% by 2030 and 100% by 2045.

Commission vetted this methodology in the PCIA OIR and asserted that these properly represented the market value of PG&E's assets.[43] Second, it would make revenue allocation among rate classes consistent with revenue allocation between bundled and departed load customers.

The California Public Advocates Office (Cal Advocates) made this same proposal in its testimony; AECA supports this recommendation of a capacity value of $56.10 per kilowatt-year.[44]

3.2. Agricultural Demand Is Variable than Energy Load So Distribution Marginal Costs Are Overestimated

Errors in PG&E's load data are evident from an examination of the underlying billing determinant data used to prepare PG&E's revenue allocation analysis. PCAF and FLT loads are relied on to allocate generation capacity, primary distribution, secondary distribution, and distribution new business primary costs. They are therefore among the most important inputs to the revenue allocation analyses.[45] Unfortunately, PG&E's marginal cost analysis assumes that PCAF and FLT data moves in lockstep with energy loads. The Agricultural Parties raised these issues in their comments on PG&E's Agricultural Balancing Account Study (Study); PG&E made minimal changes in its report in response.[46]

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[43] Decision 18-11-019 in Rulemaking 17-06-026.

[44] Public Advocates Office, Initial Testimony, A.19-11-019, October 23, 2020, p. 3-1.

[45] PCAF is the sum of coincident peak loads for the class over a period that covers the highest system load hours. FLT is the sum of peak loads on the final line transformer for each customer. Distribution PCAFs include all customer load. Generation PCAFs include only bundled customer load.

[46] PG&E, *Pacific Gas and Electric Company's (PG&E) Agricultural Balancing Account Study with Agricultural Parties' Addendum*, Final Report, September 30, 2016.

A notable issue is that the PCAF and FLT data that PG&E provided in its last two GRC workpapers and Study do not match, despite both being issued initially in June 2016.[47] PG&E provided AECA with a set of annual data responses since 2016 as a follow on to the 2017 GRC that included corrections to data filed with the 2014 GRC that addressed some of the unexpected data points.[48] However, as Cal Advocates noted, problems still exist in PG&E's database of PCAF and FLT values.

Analysis of PCAF and FLT data for 2003 to 2019 finds that the relationship of demand to energy load shows rising peak loads for residential customers while other customers demonstrate a flattening load. Agricultural customers in particular exhibit a steeper demand decline relative to load than other rate classes. Changes in demand-to-load should be reflected in marginal cost-based revenue calculations by increasing respective billing determinants by the rates shown in Table AECA-6.

Table AECA-6 PCAF and FLT Relationship to Energy Load

	FLT/kWh Trend/Yr	Gen PCAF/kWh Trend/Yr
Residential	0.7%	2.0%
Commercial	-0.3%	-2.1%
Industrial	5.4%	-0.7%
Agricultural	-1.7%	-0.9%
Total	0.8%	0.1%

[47] PG&E, *Pacific Gas and Electric Company's (PG&E) Agricultural Balancing Account Study with Agricultural Parties' Addendum*, Final Report, September 30, 2016.

[48] 2014 GRC data was provided in AECA_GRC-2017-PhII_DR_CFBF_005-Q01Atch01_CONF.xlsx. Data was provided for the years 2016 to 2019 in response to 2017 GRC-2017-PhII_DR_AGParties_DataRep_2017-A-Q01_B-Q01.pdf and GRC-2017-PhII_DR_AGParties_DataRep_2017-A-Q01_B-Q04.pdf.

3.3. Marginal Customer Access Costs Should Reflect Both New Connection Costs and the Opportunity Value of Existing Connections

Marginal costs are composed of more than just direct accounting cost of production for a good or service. They also include the opportunity cost or value of using that good or service elsewhere or of selling it to a different consumer or producer.[49] While the costs of new connections is one component of the marginal cost for customer access, another is the value to existing customers who are able to sell their utility connections to other buyers, for example when they sell their house.[50] This principle can be used to calculate a marginal customer access cost (MCAC) that reflects the principles of both the real economic carrying charge (RECC) and new customer only (NCO) methods while addressing their flaws.

3.3.1. Both PG&E's RECC Method and Cal Advocates NCO Method Fail to Fully Capture the Economic Principle of Opportunity Cost

For customer access costs, the Commission has yet to provide definitive guidance on whether to use the new customer only (NCO)[51] versus the real economic carrying charge, or RECC, method. In one set of decisions the Commission appeared to favor the RECC method for MCC determination, including in the only proceeding dealing explicitly with long-run marginal costs.[52] In another set, the Commission seemed to endorse the NCO method.[53]

Introduction of the NCO method to calculate marginal customer access costs (MCACs) reflected the Commission's recognition that existing customers are likely subsidizing new

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[49] C.E. Ferguson and J.P. Gould, *Microeconomic Theory*, Richard D. Irwin, Inc., Homewood, Illinois, Fourth edition, 1975, Chapter 7.

[50] "Teardown" house sales illustrate the most striking example of this type of transaction, in which a home is sold with the intent of demolishing and rebuilding it with almost a clean start. Existing utility services generally are left intact because they have value to the new homeowner.

[51] The NCO method and One Time Hookup Method are not the same. The One Time Hookup Method directly assigns customer service costs to a new customer at the time of connecting service, as specified in Ronald C. Griffin, "Effective Water Pricing," Journal of the American Water Resources Association 37, no. 5 (2001): 1335-47. The NCO method spreads new hook up costs to all customers.

[52] D.92-12-057, D.95-12-053, D.96-04-050, and D.97-04-082.

[53] D.92-12-058 and D.97-08-062 (reversing specific parts of D.97-04-082).

customers through rates.[54] Unfortunately, the NCO method has the *opposite* effect—it increases the subsidy to new customers. The NCO method takes the costs of adding new customers within a rate class (*e.g.*, domestic, commercial, industrial, agriculture), divides them over *all* customers—new and existing—and defines that as the "marginal cost" of customer services for all customers in that rate class. The NCO method does not allocate costs to individual customers, but rather treats classes of customers as though they are aggregated into one large "super" customer that shares the costs of adding incremental load. As a result, a new customer receives a line extension allowance that is supposed to be paid back through future rates, but the cost of that allowance is divided over all customers, essentially leading to repayment of about 1% of those costs each year. In other words, new customers are provided service interconnection essentially for free as reflected in the marginal cost calculations.

In addition to creating a subsidy, the NCO method produces an overly volatile estimate that does not reflect actual market behavior and is not supported in the economics literature. More importantly, proponents of the NCO method fail to demonstrate how costs will be recovered over the long run.

The fundamental error in the NCO method, clearly identified as a desirable trait in Cal Advocates testimony, is that the opportunity cost of existing connections is asserted to be zero.[55] In other words, once a service connection is built, it purportedly has no value to any other customer. Of course, this concept is false. As one example, once a house is built, the house still

[54] NCO's development coincided with major revisions to line extension rules in the 1990s. Line extension allowances had previously been based on "footage" payments rather than cost limits. See D.94-10-030. D. 97-12-098 in Rulemaking 92-03-050, Finding of Fact 12 states the new allowance is intended to end the subsidy of new customers.

[55] Public Advocates Office, Initial Testimony, A.19-11-019, October 23, 2020, p. 1-5.

has value that can be realized by selling to another resident or landlord.[56] A service connection is what makes a house viable—it is a virtually universal requirement that a residence have an electrical connection before a municipality in California will certify that it is habitable. The question is not whether an existing connection has value, but rather what is that value?

The RECC, or "rental", method has been the dominant alternative to NCO. The rental method takes the long-term cost to serve a new customer and presumes that the RECC is the "market" price of service for all customers, new *and* existing. Since the utility owns all customer services, the presumption is that *all* – new and existing – customers are paying a rental fee to the utility based on this market signal. The rental method provides an estimate of marginal customer costs that is relatively invariant with demand and fails to recognize that older service connections have less value as they depreciate, just like a used car.

To be consistent with market behavior, the rental method should account for the average remaining life of the stock in place. The Commission has used this principle previously in valuing the acquisition of local distribution systems by municipal utilities, by setting the price at the replacement cost new less depreciation (RCNLD).[57] This same principle can be used to calculate the value of existing customer service connections.

3.3.2. Combining New Costs for New Connections and RCNLD for Existing Connections Best Captures Opportunity Cost for Setting Marginal Costs

The true marginal costs for customer access connections must include both the costs for new customers and the opportunity cost or value for existing connections to be consistent with

[56] CalAdvocates make a further error in asserting that competitive markets require that customers be able to own an asset. There is nothing in fundamental economic principles that supports this assertion; Cal Advocates offer no supporting evidence or citations. Many other competitive asset markets exist where customer ownership is virtually or entirely nonexistent, such as airplanes for transcontinental travel and rental cars.

[57] See for example Decision 04-03-036 authorizing PG&E's sale of the Mountain Home development franchise to Modesto Irrigation District.

economic principles and how markets function. The value of the entire housing stock is not set solely by the cost of constructing new houses, nor are existing houses determined to be valueless. The method proposed here best reflects the balance of values for new construction and existing infrastructure using principles already adopted by the Commission. The costs must be calculated on an annual basis to be temporally equivalent to the marginal costs for generation and distribution assets.[58] New customer costs are best represented by the RECC method.

For existing customers, the RCNLD cost can be calculated based on the weighted average age of the different segments of the connection cost—transformer, service and meter (TSM). The expected and remaining service lives for customer services are shown in PG&E's GRC Phase I workpapers.[59] Overall, existing services have about 28.1 years of expected remaining life, and customers would expect to pay a market price that reflects their current position on the grid. The weighted average of these two overall cost components then equals the total marginal customer access cost. The weighted average for the TSM remaining life is calculated based on the booked remaining life in PG&E's depreciation workpapers.

The total marginal customer equipment cost is calculated by adding the sum of the remaining value in the TSM plus the sum of new connection costs, and dividing by the total of customer connections, new and existing. This calculation arrives at the weighted average of the TSM investments akin to RCNLD while adding brand new investments. By adopting this approach the Commission would advance a policy that is consistent with how it values these and similar assets for other transactions.

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[58] This temporal discontinuity is another flaw of the NCO method. It adds the sum of one-time upfront costs to the annualized costs for distribution and generation.

[59] PG&E, 2020 General Rate Case, Phase I, A. 18-12-019, PGAE-11 WP, Depreciation Vol. 2, GRC-2020-PhI_Test_PGE_20181213_545427.pdf

3.4. The Agricultural New Connections Forecast Should Reflect AECA's Changes to PG&E's Load Forecast

As discussed above, AECA proposes a forecasting method that incorporates relevant variables that reflect economic and physical factors that drive agricultural demand and averages forecasts for normal, wet and dry years because a "normal" year is not an "average" year. These revised forecast models include new customer connections.

PG&E's workpapers contain several different estimates of new customer connections and loads, some not consistent with recorded data that PG&E has filed in its ERRA Forecast applications.[60] For example, 2017 data for agricultural customers contained in PG&E's GRC workpapers is 1.5% less than the number shown in PG&E's ERRA Forecast Table 2-3 workpapers filed in each application since 2018. PG&E's billing determinants workpaper shows yet a third value that is in between the other two.

Similarly, agricultural load data and forecasts differ significantly between ERRA and GRC workpapers. In 2017, recorded data in the ERRA filing is 2.4% higher than what is shown in the GRC workpapers. The 2021 ERRA agricultural load forecast is 6.7% higher than the forecast used in GRC workpapers. For this reason, the Commission should require PG&E to closely review its workpapers and various filings to ensure that that they are using consistent data across applications.

AECA's forecast method finds that agricultural customer new connections will decline through 2021 given expected economic conditions and assuming average hydrologic conditions. As a result, the agricultural class should show no new customer connections in the MCAC calculation.

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[60] Few of these values are shown directly in PG&E's workpapers; they are calculated in AECA's supporting workpapers.

4. Proposed Revenue Allocations

4.1. The Volatility of EPMC-Based Allocations Underscores the Need for Commission Policy Intervention to Provide Rate Stability

Assigning marginal costs and allocating revenue responsibility to the agricultural class has always been challenging, particularly as urban growth expands into and intermingles with formerly agricultural lands. This difficulty is illustrated by the wide swings in marginal cost estimates PG&E has asserted for the class over the years. In each case over the 1999 to 2014 GRCs, PG&E assured the Commission that it had gotten its long-run marginal cost calculations "right," and that the Commission should consider moving to full EPMC-based revenue responsibility. Yet, PG&E proposed a 29% *decrease* in revenue responsibility for agriculture in 1999 based on EPMC, after proposing a 54% increase in the 1996 GRC.[61] In the 2014 GRC, PG&E proposed a 22% increase. In other words, according to PG&E, agriculture's EPMC allocation has increased by 51% from 1996 to 2014 with no explanation of why the past estimates were wrong. In the 2017 GRC, PG&E proposed a freeze on marginal cost-based revenue allocations due to many factors changing simultaneously, such as changes in season and time period definitions and rate schedule consolidations.

In this case, PG&E again has asked for a significant increase in assigning revenue responsibility to agriculture. Yet there is still significant uncertainty about the validity of the utility's underlying calculations. The dramatic instability of PG&E's marginal cost estimates and EPMC-based allocations undermines confidence in the ratesetting process, and indicates that

[61] "While the Commission expressed concern in D. 97-03-017 that the adopted method of computing marginal costs and revenue allocation for agriculture would result in a 54 percent increase in the classes' equal percentage of marginal cost ("EPMC") target, and rates far in excess of those charged other agricultural customers in the state, employing such a methodology today would result in even higher rates." Steven J. Moss, "Prepared Direct Testimony of Steven Moss on Behalf of Agricultural Energy Consumers Association," A.99-03-014, 1999, p. 2.

PG&E's marginal cost estimates, at least for the agricultural community, remain largely unsubstantiated and methodologically unjustified.

4.2. Agriculture's Appropriate Revenue Allocation Is Lower than Proposed by PG&E

Table AECA-7 summarizes AECA's proposed revenue allocation changes before capping. PG&E recommends a 4.2% increase in revenue responsibility for agriculture; a combination of corrections to marginal cost methods and in the agriculture sales forecast results in a class average decrease of 0.6%.

Table AECA-7 Summary of Changes in Revenue Allocation

	AECA Proposed Average Rate	PG&E Proposed Rev Alloc Change	AECA Proposed Rev Alloc Change	AECA vs PG&E Avg. Rate Difference
Residential	$0.19676	-1.2%	-2.2%	-1.0%
Small	$0.22918	6.1%	7.2%	1.0%
Medium	$0.17964	-0.2%	-1.7%	-1.5%
E-19	$0.14617	-2.3%	0.1%	2.5%
Streetlights	$0.21838	-4.5%	-3.8%	0.7%
Standby	$0.17518	-3.3%	-1.8%	1.5%
Agriculture	$0.23247	4.2%	-0.6%	-4.8%
E-20 T	$0.09170	-0.1%	0.2%	0.3%
E-20 P	$0.12667	-2.4%	-0.4%	2.0%
E-20 S	$0.14099	-4.5%	-2.6%	2.0%
System	$0.17601	0.0%	0.0%	-0.3%

4.3. State Law Requires that PG&E Cap Agricultural TOU Rates at the System Average Rate

Public Utilities Code Section 744(c) requires that investor-owned utilities offer time-of-use agricultural rates at an appropriate discount from the system average rate:

> *Every electrical corporation furnishing electricity to an agricultural producer shall, in addition to its regular service, prepare and file tariffs providing for an optional off-peak demand service, including the availability of time-differentiating meters or other*

measurement devices, to any agricultural producer providing for furnishing electricity to the agricultural producer during periods of off-peak demand and which the commission finds are reasonable in relation to the needs of the electrical corporation for reduction in demand to meet system peak requirements and the burdens imposed upon the agricultural producer of scheduling its operations to coincide with the periods of off-peak demand. The off-peak demand service tariff shall be composed of a two-part time differentiated schedule consisting of on- and off-peak rates. ***The commission shall establish the rate for this service at an appropriate discount from the system average rate, which shall be not less than the cost of furnishing this service.*** (Emphasis added)

The directive from the State Legislature is clear: rates for agricultural customers on TOU schedules are to be set at an appropriate discount from the system average rate.

In response to a data request on this issue, PG&E stated that it has never considered the requirements of this law, despite AECA raising it in a previous GRC:

> To PG&E's knowledge, the CPUC has not explicitly reviewed these agricultural TOU rate options with respect to compliance with Section 744 (c). In addition, PG&E is not aware that the Commission has evaluated the meaning of the "discount from system average rate" or "cost of furnishing service" phrases in Section 744, as this statute may be subject to interpretation.[62]

First, the meaning of "discount" is obvious and means "a reduction from"—it can have no other meaning.[63] "System average rate" is reported in PG&E's workpapers and even its own testimony. The Commission has interpreted the "cost of furnishing service" as differing from the

[62] 2011 GRC PG&E Data Response AECA_002-22.
[63] See definition at https://www.merriam-webster.com/dictionary/discount.

basic rates developed in GRCs to establish economic incentives and for diesel engine conversion programs (*e.g.,* AG-ICE).[64] In the 2011 GRC, the Commission found that the "average cost of service" as defined in PUC Code Section 739.5 should not include the EPMC scaler when calculating the cost to serve a customer.[65] Also, the Commission has reauthorized the economic development rate (EDR) for qualifying industrial customers, setting the price floor at the cost of service equal to marginal cost plus the public purpose program charge.[66] The Commission has clearly decided that the "cost of furnishing service" is the marginal cost developed in this GRC proceeding. Based on the Commission's finding and AECA's cost calculation, agricultural TOU rates exceed the threshold set in Section 744(c). PG&E should be required to comply with State law and offer the discounted tariff required by Section744(c).

PG&E's proposes a system average bundled rate of $0.25664 per kWh in this proceeding. The utility recommends an average agricultural rate of $0.26573 per kWh, all of which are now TOU-based and all of which are above the rate cap set in Section 744(c). To properly implement Section 744(c), PG&E should reduce its proposed rates for all agricultural tariffs by an average of 3.5%, with rate reduction limited by the marginal cost of service for each rate class. Only the AG-5 rates proposed by PG&E fall below the statutory rate ceiling. All other agricultural accounts will be on TOU rates by 2021 and, therefore, should receive the discounted rate specified in Section 744(c). The Commission should direct PG&E to file agricultural tariffs that comply with Section 744(c).

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[64] Decision 05-06-016.
[65] Decision 11-12-053, p. 46.
[66] Decision 13-10-016, referring to Decision 07-09-016.

5. Agricultural Rate Design: Commission Should Favor Stability and Thoughtful, Expansive, Array of Options to Mitigate the Transition in TOU Periods and Pricing

In the 2017 GRC Phase II, PG&E proposed significant modifications to non-residential TOU rate schedules through 2023. However, this may be initiating a period of instability in TOU periods, rates and customers' bills.

5.1. Exclusive Focus on the Short-Run "Net Load" Undermines Accurate Assessment of TOU Periods

The IOUs, including PG&E, have advocated that the costs that drive TOU rates should be largely, or even exclusively, derived based on conventional fossil generation. As previously discussed, PG&E relies on adjusted net load (ANL), in which all load being met by non-fossil generation is subtracted from overall load; only the costs to meet the shrinking sliver of the utility's demand is considered in setting prices. This perspective excludes contributions made by utility-scale renewables that meet most of the remaining load, and by customer-side resources, including agricultural load shifting.

The marginal energy costs derived in this manner, which are driving PG&E's proposed shifts in TOU periods, reflect less than one-third of total average utility rates. Within the generation component, cost currently varies only about 20% between peak and off-peak periods; overall cost of service varies by less than 10%. Transferring half of the generation costs to the flat-rate PCIA as proposed by PG&E further suppresses the TOU signal. Why cost differences within a modest component of overall rates should steer determination of TOU periods is not obvious.

This tunnel-vision focus on "net load" rather than the entirety of load is especially problematic in the context of state policy to phasedown fossil fuel generation. Eventually, this remaining production will disappear from the grid, leaving no price-setting metric. This approach

is akin to evaluating the economics of ridesharing based on the cost of taxis without consideration of transportation network companies such as Uber and Lyft as alternatives.

Instead, the Commission should consider alternative methods to determine TOU characteristics well before non-fossil fuels represent a majority of generation. Once fossil-fuel resources are used minimally – as demanded by Senate Bill 100 (2018)[67] – and potentially no longer on the margin, it is unclear what price benchmark the utilities will use to set TOU rates. Relying solely on the cost of generation resources that state policy plans on phasing out to define TOU periods is inconsistent with good, long-term, ratemaking principles.

Rather than waiting for the day of reckoning, the Commission should focus on using a pricing method (TOU or otherwise) that acknowledges the path to the future. AECA has long advocated for a rulemaking that focuses on revising marginal costs calculations so that they recognize the long-run costs that influence the lion's share of overall rates. Instead of using "net load," proposed TOU period changes should document shifts in electricity use of all resources, including incremental renewables, distributed generation, demand response, energy efficiency, and customers' responses to rate incentives. Investments in the distribution and transmission system also should be considered. The TOU OIR decision, Findings of Fact 15, 18 and 19, acknowledge this.[68] The Commission should revisit the currently accepted TOU periods to better reflect the future rather than the status quo presented by the incumbent utilities.

[67] Public Utilities Code Section 454.53.
[68] Decision 17-01-006.

5.2. Agriculture's Unique Diversity Should Inform TOU Options, Including Eligibility for Grandfathering into Existing Periods

In the 2017 GRC Phase II, PG&E consolidated a number of rate schedules and eliminated flat rate options entirely. While rate consolidation might make PG&E's life easier, with less complicated billing, it offers little to agriculture. Distributed energy resources (DER) are providing new ways for energy users to manage their load. The shape of the grid's supply curve is bending under the weight of renewable energy capacity additions. Rather than offer creative solutions that enable agricultural customers to integrate with the emerging system, PG&E wants to vastly shrink farmers' options to harness electricity prices to finance beneficial energy management investments.

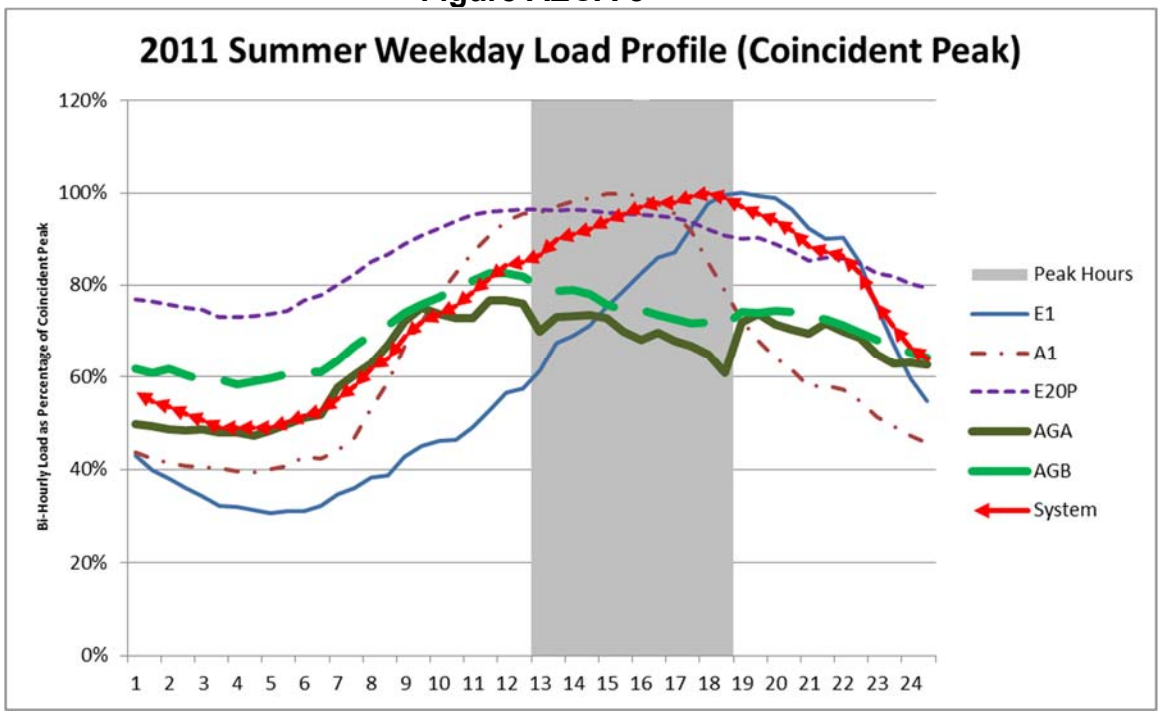
While AECA acknowledges that legacy tariffs may no longer fit *future* needs, providing the right set of price signals is a critical building block for agricultural enterprises and the electricity system. Offering reliable commitments to agricultural customers to enable them to recover past investments would encourage future beneficial investments.

In its 2016 Time of Use OIR decision, the Commission mandated that investor-owned utilities take steps to minimize the impact of TOU period modifications on those who have made investments to reduce their peak period energy use. The CPUC should allow agricultural customers who have shifted their loads away from existing peak periods to stay on rate schedules that reflect the same periods and cost differentials for up to 10 years, thereby enabling them to recoup their investments over a sufficient time period.

Farmers responded to past TOU rate incentives more consistently and enthusiastically than any other customer class. Figure AECA-8 displays how demand from AG-A (smaller) and AG-B (larger) meters relate to system-wide load on a peak summer weekday in 2011, comparing hourly loads to those at the coincident peak hour. Agriculture's response is not just relatively

better—it has been absolutely better than any other customer group.[69] Both the smaller AG-A and larger AG-B meter demand was more responsive to legacy TOU periods, to the grid's benefit, than a range of representative rate schedules.

Figure AECA-8



Agriculture's aggregate load shape on a summer weekday was inverted relative to system peak, unlike other rate classes, even as compared with industrial E-20 customers, who are usually considered among the least "peaky" rate schedules. In other words, agricultural usage actually decreased during peak periods. Agriculture tariff groups are the only ones that demonstrate an *inverted* profile: off-peak loads are higher than on-peak loads. In fact, all other rate schedules shown hit their annual peak on the same peak day within the current peak hours of noon to 6 p.m. In contrast, agriculture electricity demand was less than 80% of its annual peak during those high-load hours, with its daily peak falling outside the peak period.

[69] PG&E Data Response GRC2014-Ph-II_DR_AECA_001-Q31.

It is important to note that agriculture's avoidance of previous peak hours occurs during the summer growing season, which still coincides with the metered peak system demand. The Commission could not ask for a better aggregate response to the electricity system's needs, in stark contrast to the profiles for all other customer groups.

But that response was premised on an important, immutable physical fact—that farmers and their employees were able to get into their fields during daylight to safely and efficiently move and operate irrigation sets. Extending the peak load period, in which any usage triggers draconian monthly demand charges, means that shifting to off peak periods requires working in much more dangerous nighttime conditions and creates complicated labor scheduling.

Over the last several decades following initial implementation of TOU pricing, growers made significant operational changes in response to TOU differentials between peak and off-peak energy prices to minimize their on-peak consumption. These include substantial investments to purchase additional irrigation equipment, upgrade storage and conveyance infrastructure and reschedule labor use.

Significant changes in peak period price differentials increase uncertainty over whether large investments in high-efficiency microdrip systems – which typically cost $2,000 per acre – will be financially-viable. Microdrip systems have been adopted widely by growers over the last several years—one study of tomato irrigation rates in Fresno County could not find any significant quantity of other types of irrigation systems.[70] Contrary to strong Commission direction to incent customers to avoid peak power usage,[71] the utility's proposal would serve to

[70] Such as flood, furrow or sprinklers. (Bryan Thoreson, Davids Engineering, personal communication, 2017.)

[71] Decision 06-05-038.

penalize, and reverse, the great strides the agricultural class has made benefiting the utility system over the last four years.

According to the TOU OIR Decision at Finding of Fact 11, "…shifts in TOU time periods are the result of changes in system cost and usage patterns resulting from changes such as increased on-site solar systems and increased renewable generation connected to the grid."[72] Agriculture's significant response to time variant rates previously adopted by the Commission also has influenced the shape of the entire system load. The patterns described above demonstrate that agriculture's response to tariff structures are a key source of TOU-induced shifts. Agricultural customers deserve the same consideration as those who invested in solar and renewable generation, particularly since farmers have accomplished shifting through energy management rather than increased generation, a strategy that is higher in the state's loading order.

Growers reasonably want to be able to recoup the long-term outlays they have made to shift load from previously-identified high cost periods, as requested by the Commission and the utilities, to the benefit of all ratepayers. Without stability in legacy TOU periods, growers will be much less willing to make future investments, which risk being stranded.[73] Such rate instability could lead to customers chasing their tails to reduce loads during constantly moving peak periods. As customers shift usage away from the peak period, a new period becomes the new peak period and the utility increases costs of service in that new peak while dropping the costs in the old peak period. And the cycle begins again. Customers cannot gain any stability in pricing

[72] D.17-01-006.

[73] AECA notes that if investor-owned utilities faced similar circumstances, they likely would claim, as they have previously asserted related to the competition transition charge and power charge indifference adjustment, that their assets had been "stranded," and insist on full recovery on prior investments.

so that they can determine the payback period on their investments, so they do not make the investments.

5.2.1. Agricultural Customers Should Be Offered the Option of Remaining on Legacy TOU Periods for 10 Years to Encourage Investments to Manage Loads for Societal Benefits

PG&E's new peak period for agricultural customers from 5 p.m. to 8 p.m., seven days a week, forcing all agricultural customers into a new early evening peak TOU schedule would undermine the state's progress in reducing agricultural water use. Lower midday prices will lead to increased irrigation during the hottest times, which in turn will raise evapotranspiration rates and trigger higher applied water use.[74] The State Water Resources Control Board recognized the importance of encouraging nighttime irrigation when it issued its drought regulations in 2015, mandating that local agencies impose restrictions on lawn sprinklers.[75]

Farmers will have much more difficulty in changing electricity use in response to these new periods. Having to wait until 8 p.m. to turn on irrigation systems means that growers' labor crews would have to work in the dark under possibly hazardous conditions to comply with the new pricing periods, creating safety hazards. They also will not be able to check for system leaks and breaks when they restart in the dark. With the demise of weekend off-peak periods, the changes would have to be managed seven days a week, requiring completely resetting long-established irrigation schedules. The new periods are likely to lead to much reduced response from the agriculture sector and the loss of the reliability benefits that all ratepayers have enjoyed to date.

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[24] See for example: Fedro S. Zazueta, "Evaporation Loss During Sprinkler Irrigation," IFAS Extension, University of Florida, Bul. 290, https://edis.ifas.ufl.edu/pdffiles/AE/AE04800.pdf, November 2011.

[75] State Water Resources Control Board, "Resolution No. 2015-0032: To Adopt an Emergency Regulation for Statewide Urban Water Conservation," May 5, 2015.

Offering farmers the opportunity to grandfather into their existing TOU rates for at least 10 years reflects no different treatment than honoring a power purchase agreement with a generator. Treating generator investments differently than that of customers runs counter to the Commission's mission of protecting ratepayers against market imbalances. This lack of respect for customers' investments undermines the state's load order that puts customer energy efficiency investment as the highest priority. This treatment would be consistent with the Commission approved program to incent the conversion from diesel engines to electric motors for irrigation pumps. Those customers were given a fixed price rate for 10 years that justified the cost of investments to switch motive sources. Growers will need similar considerations to facilitate the transition in TOU periods after those growers made such significant investments to comply with previous Commission policies and directives.

5.3. PG&E Should Offer Innovative Rate Options that Address Emerging Needs

AECA proposes that PG&E offer agricultural customers a daily demand charge in lieu of monthly assessments; a real-time pricing tariff; a renewable integration rate; and account aggregation. These rate options would enable the utility to better manage distribution system demands and integrate renewables, while providing growers with concomitant incentives to engage in socially beneficial investments. A daily demand charge has an additional benefit of allowing agricultural customers to sporadically operate late in the peak period without incurring a full month's work of charges. That would significantly reduce the adverse consequences to the sector from shifting the TOU periods after growers had worked to accommodate the previous TOU framework.

5.3.1. PG&E Should Deliver on the Promise of Advance Metering Infrastructure and Implement Daily Demand Charges

Monthly billing cycles are purely arbitrary measures that have nothing to do with resource planning or acquisition, particularly in a world in which SmartMeters can record demand in 15-minute increments. Monthly billing periods are an artifact of administrative convenience and reliance on "dumb" meters and bear no relationship to actual cost causation. Monthly demand charges are just a means of collecting a hidden fixed charge for customers whose demand levels are largely fixed, like a water pump that runs at just one output level.

Distribution, and most generation, investment is recovered through an annual revenue requirement. Wholesale transmission is charged on a dollar per kilowatt-day or per kWh basis; energy is delivered in hourly units. The only relevant physical cycles are annual, seasonal and diurnal. Growers should not have to manage their loads by keeping track of PG&E's obscure billing cycles, which may be different for each account managed by a farmer. Moving to daily demand billing would greatly enhance growers' ability to manage their loads aligned to the correct incentives, to the benefit of all ratepayers.

Under monthly billing, since most pumps run either at full load or not at all, once a grower turns on a pump, the price signal from a demand charge is irrelevant for the rest of the month.[76] In contrast, a daily demand charge would offer a price signal each day, and can be structured to more accurately reflect actual cost savings from energy management.

Under AECA's proposal, demand charges would be calculated in two ways. For peak and part-peak charges, monthly costs would be divided by the number of days with peak and part-peak hours in the relevant season. For peak, this means excluding weekends and holidays.

[76] AECA has advocated for aggregation as one means of incenting growers to manage their loads all month long (and we discuss that again below).

For maximum demand charges, monthly charges would be divided by the total days in the relevant season.

If PG&E has compelling reasons to believe that daily demand charges are unworkable, then AECA proposes that all demand charges should be converted to energy charges. It is fairly straight forward to show how demand charges set on an arbitrary monthly basis quickly devolve to TOU-based energy charges.

5.3.2. PG&E Should Offer Alternative Dynamic Pricing Options to Agricultural Customers

AECA believes that the voluntary dynamic pricing schedule PA-RTP offered by Southern California Edison (SCE), [77] or one like it, may provide agricultural customers more cost-effective price signals than PG&E's proposed dynamic rates. SCE's tariff delivers a table of TOU prices on a year-ahead basis, adjusted for weather. Utilizing this table approach to dynamic pricing, an agricultural customer who follows weather predictions for the next few days (*i.e.*, all growers) can make better, more educated, decisions about when and where to irrigate, by estimating what the dynamic prices will be within that time period.

This approach offers agricultural customers significantly more flexibility and actionable information than the standard critical peak pricing (CPP) model and is more likely to encourage voluntary participation in dynamic pricing within the class.

AECA proposes that the Commission order PG&E to develop a rate similar to a dynamic pricing option for agricultural customers. Properly structured dynamic agricultural rates should accommodate key agricultural challenges. For example, irrigation schedules, which are often out

[77] SCE, Schedule PA-RTP, Agricultural and Pumping – Large, Real Time Pricing, https://library.sce.com/content/dam/sce-doclib/public/regulatory/tariff/electric/schedules/agricultural-and-pumping-rates/ELECTRIC_SCHEDULES_TOU-PA-3-RTP.pdf

of an individual growers' control, are usually set days in advance. If a field is scheduled to be irrigated on a particular day, equipment deployment and field preparation has to occur well before that day, inducing labor and capital costs.

Likewise, irrigation schedules are often coordinated with other agencies (*e.g.*, local water suppliers, California Department of Water Resources) days or weeks in advance. Under PG&E's current Peak Day Pricing program, coordinated responses to a day-ahead call for a shift in usage is nearly impossible, as conveyance facilities and other agencies' operational standards are reliant on a predetermined irrigation schedule that has already been submitted by the grower or the local water agency. Altering one farm's irrigation practices to account for the inherent ratchets in demand charges could impose a domino effect on other customers, with unpredictable consequences as an agency schedules water deliveries sequentially through its system.

In contrast, SCE's RTP schedule is based on weather conditions at a specific location (downtown Los Angeles for SCE) with prices tied to differing temperatures. Customers and water agencies are able to track weather forecasts, just as they do for irrigation planning, and can incorporate those into irrigation scheduling with sufficient notice. PG&E should offer a similarly structured alternative rate that better accommodates agriculture's characteristics.

5.3.3. Agricultural Customers Should Be Offered an Optional Renewable Integration Rate

PG&E should take advantage of the agricultural class' willingness to reshape their load to help address emerging renewable integration needs. Specifically, an aggregated agricultural electricity rate should be offered that matches with key system patterns, including seasonal differences:

- The California Independent System Operator's (CAISO) spring peak occurs between 8 and 9 p.m. Negative energy prices indicating over-generation appear in the middle of the

day during high renewable production days, which likely coincide with periods of high irrigation demand.

- During the summer, CAISO's coincident peak occurs about the same time as PG&E, between 4 and 5 p.m.
- During the fall, CAISO's coincident peak takes place at roughly the same time as PG&E's, between 7 p.m. and 8 p.m.
- During the winter, CAISO's coincident peak coincides with PG&E's peak demand, between 6 p.m. and 7 p.m.[78]

A low-cost solution to address these seasonal load stresses is available in the water pumping capacity operated by agricultural customers. If given the right incentives to use better electricity management tools, such as online notifications and real-time aggregated meter reporting, growers could manage their multiple pumping loads to match with peak load shifts and the variability in local resources.

AECA proposes that PG&E offer Renewable Integration Rate options to the agricultural class – AG-RIR – that are structured so that prices encourage load patterns that smooth and flatten seasonal net load curves. Tariffs should be priced to encourage shifts in peak load demand, similar to existing TOU rates, modified to fit up-to-date season-specific load curves; incentivize growers to consume during low demand periods to minimize over-generation; and reduce the need for flexible capacity resources (*i.e.,* lower the magnitude of upward and downward ramps through managed load response). For example, one RIR option could be characterized as a Base Oversupply Tariff, or RIR-BOT, which would be structured to

[78] Clyde Loutan, Senior Advisor, Renewable Energy Integration, CAISO. "Operational needs and how rate design can help," presented at the Demand Analysis Working Group, October 7, 2014, pp. 3-7, 14.

compensate agricultural customers, including irrigation districts, who could *increase* their load when called upon.

5.3.4. Agricultural Customers Should Be Allowed to Aggregate Their Accounts Virtually to Further Reduce Peak Loads to Benefit All Customers

PG&E does not offer agricultural customers the same opportunity to aggregate their loads behind a single meter that commercial and industrial customers enjoy. Instead, each meter on a farm or ranch is treated as a separate customer, billed under a specific tariff.[79] Meter aggregation would produce benefits for growers and the utility system.[80] AECA recommends that the Commission require PG&E offer tariffs that allow for aggregated loads in a similar manner to the aggregated net energy metering (NEM-V) tariff now in place.

Individual irrigation accounts – which constitute the vast majority of PG&E's agricultural customers – cannot readily shave load. The meter, or pump, is typically either 100% on or 100% off. In such circumstances, in the face of time variant rates there may be no machines to idle or lights to dim behind the meter. The grower is faced with the stark choice of running the irrigation, booster or groundwater pump, or not.

SmartMeters provide the Commission with an opportunity to provide growers with a tool to better manage their load. If multiple pumps could be placed on the same rate and bill to be monitored by a single meter; some could be turned on, others off, in ways that maximize resource benefits to the grower and the system.[81] As part of this advancement, the Commission

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[79] AECA has long identified PG&E's failure to account for agricultural load diversity created by this unique treatment, which is a factor influencing the utility's flawed revenue responsibility allocation to the class. See Richard McCann, "Prepared Direct Testimony of Richard McCann, Ph.D. on Marginal Costs, Revenue Allocation, And Rate Design Issues on Behalf of the Agricultural Energy Consumers Association," Before the California Public Utilities Commission, A.13-04-012, December 13, 2013.

[80] PG&E, "Agricultural Account Aggregation Study," March 7, 2014.

[81] Current agricultural load profiles fail to account for significant disparities in customer demand characteristics, and to distinguish coincident loads. As a result, PG&E continues to significantly overestimate agriculture peak demand. If farmers had been allowed to aggregate all of their loads on a circuit, their aggregated

should ensure that PG&E makes data from all accounts readily accessible and manageable for individual customers, so that they can take advantage of SmartMeter information to actively manage their electricity use. Metered data is currently difficult to access, download and manage because of inadequacies in PG&E's metering and billing infrastructure.

Aggregation through *accessible* SmartMeter data and ratemaking principles, would facilitate better energy management and serve a broader Commission goal of reducing total peak demand. If a contiguous farm is defined – for example, as under the dairy biogas net metering program[82] – the true demand of that operation as an integrated whole can be readily understood through the use of advanced meters.

Because agricultural accounts now tend to be single-use loads, a grower is indifferent as to whether he runs two pumps simultaneously; the grower's total utility bill across all accounts will be the same. With aggregation, that same grower would have an incentive to run those two pumps at different times of day, or even on different days of the week, to minimize total billing demand. Other ratepayers would benefit through real reductions in total peak demand that would serve to decrease the utility's total revenue requirement. Agricultural customers could realize substantial savings if growers were allowed to virtually aggregate their loads and demonstrate that their true capacity demand is much lower than currently assessed.

The Commission should order PG&E to develop and adopt virtual master metering programs and associated tariffs, to enable growers to aggregate the load used by multiple accounts on a single ranch or farm. Such a program is already available for sharing distributed

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billing demand would have decreased by 16%. In other words, the measured coincident demand for these customers would be only 84% of what PG&E records in its billing determinants. PG&E, *Report on the Load Characteristics of Multiple-Account Customers on PG&E's Service Territory*, Prepared in Response to AB 1421 (1999), July 2, 2001.

[82] Public Utilities Code 2827.9

generation through net metering of adjacent parcel loads. This approach should be expanded to include agricultural accounts

6. Conclusions

AECA recommends that the Commission adopt the changes in marginal cost calculations and revenue that lead to the conclusion that agricultural rates should decrease 0.6% using a cost-based allocation. This contrasts with PG&E recommendations for increases of 4.5% over one year, 8.4% over three years and 17% over six year.

AECA also makes the following proposals to change how PG&E's marginal costs are calculated and revenues allocated to individual customer classes.

1. Agricultural load forecasting must be revised to more accurately represent the dominate role variations in water supply availability play in shaping agricultural load
2. The Commission should adopt the MPBs used to establish the PCIA to determine marginal costs for revenue allocation to be more consistent with other proceedings and transparently reflect marginal costs as reflected in market valuation. These include adding the value of RECs to the MEC and using the RA MPB to value capacity.
3. The differences in customer class-specific growth rates should be added to the PCAF and FLT billing demands used to calculate marginal costs.
4. MCAC should be calculated by reflecting the opportunity cost of current customers' services and adding this to the proportional share of new services added for the class.
5. For purposes of calculating the MCAC using this method, the agricultural class growth rate should be set at zero.

6. PG&E should be ordered to comply with Public Utilities Code Section 744(c) which caps each agricultural time of use average rate at the system average rate.
7. The Commission should protect growers' investments in efficient irrigation systems, which were adopted in part to safeguard the state's water resources by allowing them to stay on legacy TOU periods.
8. Agricultural customers should be offered account aggregation similar to that provided through virtual net metering.
9. The Commission should require PG&E to closely review its workpapers and various filings to ensure that that they are using consistent data across applications.

STATEMENT OF QUALIFICATIONS: RICHARD McCANN, PH.D.

POLICY ANALYSIS FOR THE PUBLIC AND PRIVATE SECTORS
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Professional Experience

M.Cubed, Partner, 1993-2008, 2014-present
Aspen Environmental Group, Senior Associate, 2008-2013
Foster Associates/Spectrum Economics/QED Research, Senior Economist, 1986-1992
Dames & Moore, Economist, 1985-1986

Academic Background

PhD, Agricultural and Resource Economics, University of California, Berkeley, 1998
MS, Agricultural and Resource Economics, University of California, Berkeley, 1990
MPP, Institute of Public Policy Studies, University of Michigan, 1986
BS, Political Economy of Natural Resources, University of California, Berkeley, 1981

Selected Relevant Projects

Electricity Testimony and Resource Planning

- **Regulatory Analysis and Support, CalCCA (2018-present)**. Testifying at the California Public Utilities Commission (CPUC) in rulemaking proceedings on the power charge indifference adjustment (PCIA) "exit" fee and resource adequacy.
- **Regulatory Analysis and Support, Sonoma Clean Power (2016-present)**. Testifying at the California Public Utilities Commission (CPUC) in Pacific Gas and Electric's (PG&E) rate proceedings on the power charge indifference adjustment (PCIA) "exit" fee and other issues.
- **Regulatory Analysis and Support, CalChoice (2017)**. Testifying at the California Public Utilities Commission (CPUC) in Southern California Edison's (SCE) rate proceedings on the power charge indifference adjustment (PCIA) "exit" fee and other issues.
- **Agricultural Rate Setting Testimony, Agricultural Energy Consumers Association (1992-present).** Testified about agricultural economic issues related to energy use, linkage to California water management policy, and utility rates in numerous proceedings at the California Public Utilities Commission, California Energy Commission, and California State Legislature.
- **Testimony on Protecting Solar Project Investment by Customers, County of Santa Clara (2017-present)**. Testified before the California Public Utilities Commission in PG&E's 2017 General Rate Case on preserving current time of use rate structures applicable to existing RES-BCT solar projects owned by local governments.
- **Master-Meter Rate Setting Testimony, Western Manufactured Housing Communities Association (1998-present).** Examined issues associated with the structure of and cost associated with providing electric service to master-metered mobile home parks. Testified in Pacific Gas and Electric Co., Southern California Edison Co., Southern California Gas Co. and San Diego Gas and Electric Co. rate proceedings on establishing "master-meter/submeter credits" provided to private mobile home park utility systems.
- **Master-Metered Utility Systems Transfer Program, Western Manufactured Housing Communities Association (2003-present)**. Prepared petition that opened a rulemaking to facilitate transfer of

master-metered utility systems to serving utilities and testified in that proceeding. Testified before the State Legislature on proposed legislation. Persuaded all electric and gas utilities in California to institute a pilot program to convert 10% of privately-owned MHP systems to utility ownership.

- **Community Solar Gardens Testimony, Sierra Club (2014).** Testified in Pacific Gas and Electric and Southern California Edison Green Tariff applications on changes needed to encourage the development of neighborhood and community-scale renewable distributed generation by allowing direct contracting and removing unnecessary transaction costs.
- **Time of Use Rates in California Residential Rates Rulemaking, Environmental Defense Fund (2013-2014).** Modeled how increased penetration of TOU rates in the residential sector for all three investor-owned utilities would reduce peak and energy demand, reduce residential bills, and reduce utility costs. Changes in revenues and costs were developed from the utilities' most recent general rate case filings.
- **Southern California Edison v. State of Nevada Department of Taxation, Nevada Attorney General's Office (2013-2014)**. Testified on whether the sales tax imposed on coal delivered to SCE's Mohave Generating Station created a competitive disadvantage for SCE in the Western power market during the 1998-2000 period.
- **Alternative Generation Technology Assessment, California Energy Commission (2001-2014).** Developed and maintained the Cost of Generation Model, spreadsheet-based tool used by the CEC to produce generation cost estimates for the Integrated Energy Policy Report (IEPR).
- **Time of Use Rates in Consolidated Edison Rate Case, Environmental Defense Fund (2013).** Modeled how increased penetration of TOU rates in the residential sector for Consolidated Edison serving the New York City metropolitan area would reduce peak and energy demand, reduce residential bills, and reduce utility costs.
- **Analytic Support for Long Term Procurement Plan OIR, California Public Utilities Commission Energy Division (2011-2012).** Reviewed California Independent System Operator (CAISO) and three utilities' resource acquisition plan out to 2020.
- **Exploratory Modeling Methodology Project, California Energy Commission (2008-2011).** Developed a pilot modeling exercise in cooperation with the CEC Staff and the Rand Corporation to demonstrate the usefulness of exploratory modeling techniques and their use in robust decision making.
- **Analysis of Rocky Mountain Power Pilot Solar Incentives Program, Utah Clean Energy (2010).** Analyzed ratepayer and utility impacts analysis conducted by RMP to assess whether the three-year pilot program should be extended.
- **Electricity System Simulation Modeling Methodology Evaluation, California Energy Commission (2009-2010).** Constructed and applied an evaluation structure equivalent to the California's software purchasing Feasibility Study Report for assessing acquisition of a new production cost simulation model.
- **PG&E/NID/PCWA Relicensing Economic Analysis, Foothills Water Network (2009).** Conducted economic analysis for relicensing of PG&E's Drum-Spaulding, Nevada Irrigation District and Placer County Water Agency FERC projects on the American, Bear and Yuba Rivers for coalition of environmental group, using the Stockholm Environmental Institute's Water-Energy Analysis Program (WEAP) hydropower model.
- **Reliability and Environmental Regulatory Tradeoffs in the LA Basin, California Energy Commission (2009).** Developed analytic tool in Analytica to assess local capacity requirements (LCR) in the CAISO and LADWP control areas for the 2009-2015 period, and how air and water quality regulations impact the ability to meet the LCR. The analysis was used to evaluate policy options for addressing new

regulations on once-through-cooling at aging power plants and restriction on new air permits from the South Coast Air Quality Management District.

- **Nevada Collaborative Group Renewables and Transmission Policy, Energy Foundation (2008).** Developed policy alternatives for creating incentives to finance new renewable resources and transmission access in Nevada.
- **Generation Facility Uncertainties and the Need for a Flexible Infrastructure for Nevada, Energy Foundation (2007-2008).** Assessed potential availability and costs for alternative resources to defer or replace proposed coal plants in Nevada and to better use a proposed transmission link. Co-authored *Laying a Foundation for Nevada's Electricity Future*.
- **Analytic Support for Klamath Project FERC Relicensing Case, California Energy Commission (2005-2007).** Prepared economic analysis comparing potential costs and benefits of proposed relicensing conditions and decommissioning scenarios for a consortium of government agencies.
- **US v. Reliant Resources CR04-125, US Attorney (2005-2007).** Testified in a wire fraud case as to the air quality regulatory constraints that Reliant may have faced when scheduling and operating its power generation facilities June 20 to June 23, 2000. That testimony addressed whether Reliant traders improperly used environmental regulations as a cover for illegal market manipulation behavior.
- **Agricultural Engine Conversion Program, Agricultural Energy Consumers Association (2005).** Testified before the CPUC on program to convert agricultural diesel engines to electricity. The analysis identified the rate reduction needed to induce such conversions while still covering the utilities' (PG&E and SCE) incremental costs.
- **Statewide Pricing Pilot, Track B Analysis, California Public Utilities Commission (2003-2005).** Developed experimental program to examine whether providing educational "treatments" communicated through a community-based organization in an environmentally-impacted neighborhood enhanced responses to critical peak pricing among residential energy users. The project included survey and econometric research.
- **Environmental Performance Report-Potential Impacts of Global Climate Change on California's Hydropower System, California Energy Commission (2005).** Assessed a potential range of impacts on the operations of California's hydropower system from different hydrological scenarios related to GCC projections. The interrelated nature of the hydropower, water supply and flood control systems was highlighted. Results presented in the CEC's 2005 Integrated Energy Policy Report.
- **Environmental Performance Report Hydropower Relicensing Cost Evaluation, California Energy Commission (2003).** Developed estimates of lost value and incurred costs for California hydropower facilities subject to relicensing. Results presented in Appendix D of the CEC's 2003 Integrated Energy Policy Report.
- **California Electricity Anti-trust Actions, California Office of the Attorney General (2002-2004).** Consulted on developing anti-trust cases and actions against merchant power generators as a result of the California 2000-2001 energy crisis.
- **FERC California Refund Case Testimony, California Electricity Oversight Board (2001-2003).** Testified before the Federal Energy Regulatory Commission on electricity price refund issues related to air emission and environmental permit costs, and effects on power plant operations from environmental regulations. Included analysis of the RECLAIM market performance during the crisis. EL-00-95 et al.
- **Agricultural Electricity Rates Report, California Energy Commission (2001).** Studied how electricity rates in California impact agricultural energy costs given restructuring. The report modeled groundwater pumping for multiple depths across nine crops and dairy operations. This included a

comparison with rates in neighboring states. Developed a broad range of policy proposals to improve agricultural energy management and to lower energy costs.

- **California Energy Crisis Assessment, National Rural Electric Cooperative Association (2001).** Prepared assessment of California's energy situation for summer of 2001.
- **Energy Crisis Solutions, California Energy Commission (2001).** Developed policy proposals to address coming energy crisis in the summer of 2001 for the draft executive summary of the CEC's AB970 Report. Estimated stranded cost recovery by PG&E and SCE.
- **PG&E Hydro Divestiture EIR, California Public Utilities Commission (2000).** Evaluated the environmental impacts from divesting hydropower facilities and related lands by Pacific Gas and Electric Company..
- **Thermal Power Plant Divestitures Environmental Assessments, California Public Utilities Commission (1997-1998).** Evaluated the environmental impacts of the generating plant divestiture by Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric Companies.
- **Municipalization Feasibility Study, CCSF Hetch Hetchy Water and Power (1996).** Evaluated the bulk power options and costs of other services in the restructured California electricity market in assessing the attractiveness of municipalizing the PG&E system within the City and County of San Francisco.
- **Restructuring Proposals Evaluation, Western States Petroleum Association and Shell Oil Co. (1995).** Advised clients on the implications of the proposed methods to restructure California's energy market to large consumers.
- **Restructuring and Renewables, California Energy Commission (1995).** Evaluated two alternatives to restructure California's electricity industry, by examining how the proposed market structures and methods of funding stranded assets would affect the development of a competitive marketplace. Testified for the CEC Research and Development Office, in the 1994 Electricity Report Proceedings.
- **Barriers to Biomass Energy, California Energy Commission (1994).** Assessed the institutional barriers that threaten the survival of existing biomass generating plants and limit their further development in California.
- **Municipals Avoided Costs Study, California Energy Commission (1989).** Assessed and forecasted avoided-cost rates and offers of California's 14 largest municipal utilities, using the Elfin production-cost model.
- **Gas Pipeline Need Assessment, South Coast Air Quality Management District (1989).** Prepared analysis and testimony presented to the California Public Utilities Commission on the need for additional interstate natural gas pipeline capacity to implement the Liquid and Solid Fuel Phase-out Policy for the South Coast Air Quality Management District.
- **Rancho Seco NGS Evaluation, Sacramento Municipal Utility District (1988).** Independently reviewed resource planning alternatives and recommended action on Rancho Seco NGS operations, for SMUD QUEST Team.
- **QF Avoided Cost Rates, Oklahoma Corporation Commission Staff (1989).** Testified on Oklahoma Gas and Electric avoided-cost methodology and made projections for payments to cogeneration facilities using the PROMOD production-cost model. Testified for the OCC Staff, in Cause No. PUD 000600 and Cause No. PUD 000345.
- **QF Avoided Costs Forecast, Independent Power Technologies (1989).** Prepared Pacific Gas and Electric industrial electricity rate and avoided-cost forecasts, with Diablo Canyon settlement agreement and natural gas price sensitivities, for a cogeneration developer.

- **QF Development Forecast, Sacramento Municipal Utility District (1988).** Identified and assessed the viability of qualifying facilities (QF) projects in PG&E's service territory.
- **QF Siting Certification Cases, Sun Oil/Mission Energy (1987), Signal Energy (1988), Luz Engineering (1988).** Prepared testimony on need-for-power in Southern California Edison and San Diego Gas and Electric, for three qualifying facility project siting applicants at the CEC.
- **QF Siting Certification Cases, IBM (1985), Arco Refining (1986), Mobil Oil (1986).** Prepared testimony on need-for-power in Southern California Edison and Pacific Gas and Electric, for three qualifying facility project siting applicants at the CEC.

Climate Change and Air Quality Testimony and Analysis

- **AB 32 GHG Allowance Auction Market Monitor, California Air Resources Board (2012-2013).** Supported Monitoring Analytics in monitoring operations of the AB 32 cap and trade market which launched August 2012.
- **Food Processing Industry Emission Intensive Trade Exposed Indices Analysis for AB 32, California League of Food Processors (2011).** Calculated California-specific Energy Intensive Trade Exposed (EITE) Industry Indices for California's food processing sector using federal and state data sources that could be updated by the Air Resources Board staff.
- **Petroleum Industry Emission Intensive Trade Exposed Indices Analysis for AB 32, Western States Petroleum Association (2010).** Calculated California-specific Energy Intensive Trade Exposed (EITE) Industry Indices for California's petroleum production and refining sectors using federal and state data sources that could be updated by the Air Resources Board staff.
- **Prepare Regulatory Proposals for High Global Warming Potential Gases, Environmental Defense Fund (2009).** Assessed proposed regulation of high global warming potential (HGWP) gases by the California Air Resources Board under AB 32. HGWP gases included HFCs used for refrigeration and space cooling and replacements for ozone-depleting substances (ODS).
- **Review of AB 32 Proposed Scoping Plan Economic Modeling, Environmental Defense Fund (2008).** Reviewed economic modeling by the California Air Resources Board Staff used to assess the Proposed Scoping Plan to meet greenhouse gas emission reduction goals specified in AB 32..
- **Analysis of Proposed Low Carbon Fuel Standard, Western States Petroleum Association. (2007-2008).** Analyzed the California Air Resources Board's proposed LCFS that would reduce the average carbon content for transportation fuels by 10%. This included a review of the GREET model and its inputs, and assessing life-cycle emissions for various alternative fuels.
- **Review of Economic Analysis of Proposed In-Use On-Road Diesel Fleet Regulations, Construction Industry Air Quality Coalition (2008).** Highlighted key issues in CARB Staff analysis of potential health benefits and costs to complying firms for proposed accelerated mandated scrappage and retrofit program.
- **Construction Fleet Emission Standard Impacts, Construction Industry Air Quality Coalition (2006-2007).** Reviewed ARB Staff regulatory proposal and analysis. Prepared responding economic impact analysis using the ARB's emission inventory database of 170,000 pieces of equipment.
- **Analysis of Governor's Executive Order on GHG Regulation, Environmental Defense Fund (2005).** With Lawrence Berkeley National Laboratory and Resources for the Future, described the current regulatory regime and policies for electricity related to regulated greenhouse gas emissions. This analysis was included in the state's Climate Action Team report.

- **Petroleum Reduction Strategies Analysis, Diesel Technology Forum (2003).** Analyzed California Energy Commission proposals in its AB 2076 Report for reducing California's petroleum usage. Estimated fuel use reduction through increased penetration of light-duty diesel vehicles under different market scenarios.

Professional Affiliations

- American Agricultural Economics Association
- Association of Environmental and Resource Economists
- American Economics Association

Civic Activities

- Member, City of Davis Natural Resources Commission
- Former Member, City of Davis Utilities Rate Advisory Commission
- Former Member, City of Davis Community Choice Energy Advisory Committee
- Co-Chair, Cool Davis Energy Steering Committee
- Member, Western Manufactured Housing Communities Association Utilities Task Force
- Former Member, City of Davis Citizens Electricity Restructuring Task Force
- Former Member, Yolo County Housing Commission
- Member, Phi Beta Kappa Honorary Fraternity

ATTACHMENT A

PUBLIC REFERENCES

Public Attachments

Footnote 7

A.16-06-013, Testimony of Richard McCann and Laura Norin on Behalf of the Agricultural Parties in Pacific Gas & Electric's (PG&E's) 2017 General Rate Case Phase 2 Application Addressing PG&E's Agricultural Class Balancing Account Study, March 15, 2017

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California Department of Water Resources, California Data Exchange Center, "Chronological Reconstructed Sacramento and San Joaquin Valley Water Year Hydrologic Classification Indices," https://cdec.water.ca.gov/reportapp/javareports?name=WSIHIST

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PG&E, *Pacific Gas and Electric Company's (PG&E) Agricultural Balancing Account Study with Agricultural Parties' Addendum*, Final Report, September 30, 2016.

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GRC-2017-PhII_DR_AGParties_DataRep_2018-A-Q04_B-Q04.pdf
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United States Department of Agriculture Economic Research Service. Net Cash Income—All Commodity receipts. https://data.ers.usda.gov/reports.aspx?ID=17831.

USDA ERA, "Data Files: U.S. and State-Level Farm Income and Wealth Statistics," https://www.ers.usda.gov/data-products/farm-income-and-wealth-statistics/data-files-us-and-state-level-farm-income-and-wealth-statistics/.

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ERRA 2021 PG&E Forecast DR AgParties 001-Q06 and AgParties 001-Q07.

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State Water Resources Control Board, "Resolution No. 2015-0032: To Adopt an Emergency Regulation for Statewide Urban Water Conservation," May 5, 2015.

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Clyde Loutan, Senior Advisor, Renewable Energy Integration, CAISO. “Operational needs and how rate design can help,” presented at the Demand Analysis Working Group, October 7, 2014.

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Institute of Business Forecasting & Planning (https://demand-planning.com)



(https://ibf.org/sop-maturity-model)

A CRITICAL LOOK AT MEASURING AND CALCULATING FORECAST BIAS



SUJIT SINGH (HTTPS://DEMAND-PLANNING.COM/AUTHOR/SUJITSINGH/) ✖ JANUARY 13, 2017 ✖ FORECASTING AND PLANNING (HTTPS://DEMAND-PLANNING.COM/CATEGORY/FORECASTING-AND-PLANNING/)

Identifying and calculating forecast bias is crucial for improving forecast accuracy.

Sujit Singh (https://demand-planning.com/author/sujitsingh/)

As COO of Arkieva, Sujit manages the day-to-day operations at Arkieva such as software implementations and customer relationships. He is a recognized subject matter expert in forecasting, S&OP and inventory optimization. Sujit received a Bachelor of Technology degree in Civil Engineering from the Indian Institute of Technology, Kanpur and an M.S. in Transportation Engineering from the University of Massachusetts. Throughout the day don't be surprised if you find him practicing his cricket technique before a meeting.

I cannot discuss forecasting bias without mentioning MAPE (http://arkievablog.wpengine.com/two-sides-of-the-mape-coin/), but since I have written about those topics in the past, in this post, I will concentrate on Forecast Bias and the Forecast Bias Formula.
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What Is Forecast Bias?

Forecast Bias can be described as a tendency to either over-forecast (forecast is more than the actual), or under-forecast (forecast is less than the actual), leading to a forecasting error.

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There are many reasons why such bias exists including systemic ones as discussed in a prior forecasting bias discussion. Some core reasons for a forecast bias includes:

1. **Optimism bias**: I have seen this primarily with the sales team who seem to have an abundance of confidence in their ability to sell and therefore inflate the end results.
2. **Sandbagging bias**: This is the reverse of the above and I have seen this where well-meaning executive have created a system of bonuses based on exceeding the forecasts, and this has created a culture of sandbagging.
3. **Anecdote bias**: I have heard so many instances where regardless of what the data is telling them, client personnel would be wary of seeing it because a terrible thing that happened in the past and is part of the company folklore. Their forecast is therefore biased based on the anecdotes.
4. **Recent data bias**: This is probably true for all processes where humans are involved. The more recent occurrences weigh heavier in our mind. In the case of forecasting, this can create an overreaction based on the latest events.
5. **Silly bias**: In a study (http://psiexp.ss.uci.edu/research/teaching/Tversky_Kahneman_1974.pdf) conducted by Amor Tversky and Daniel Kahneman, they asked respondents to guess the number of countries in Africa. However, they showed them a number right before asking them to guess. What they found was on average, the estimate of some countries went up when the user was shown a bigger number and went down when the users were shown a smaller number before answering the question. This makes me think a forecast could be impacted by silly things you saw before you start doing the forecast. For example, what if they saw the temperature and it was a hot day? Does that high number skew the forecast higher? What if they called someone before forecasting and the phone number was comprised of larger digits?

How To Calculate Forecast Bias

A quick word on improving the forecast accuracy in the presence of bias. Once bias has been identified, correcting the forecast error is quite simple. It can be achieved by adjusting the forecast in question by the appropriate amount in the appropriate direction, i.e., increase it in the case of under-forecast bias, and decrease it in the case of over-forecast bias.

Rick Glover on LinkedIn described his calculation of BIAS this way: Calculate the BIAS at the lowest level (for example, by product, by location) as follows:

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- BIAS = Historical Forecast Units (Two-months frozen) minus Actual Demand Units.

- If the forecast is greater than actual demand than the bias is positive (indicates over-forecast). The inverse, of course, results in a negative bias (indicates under-forecast).
- On an aggregate level, per group or category, the +/- are netted out revealing the overall bias.

The other common metric used to measure forecast accuracy is the tracking signal. On LinkedIn, I asked John Ballantyne how he calculates this metric. Here was his response (I have paraphrased it some):

-

The "Tracking Signal" quantifies "Bias" in a forecast. No product can be planned from a severely biased forecast. Tracking Signal is the gateway test for evaluating forecast accuracy. The tracking signal in each period is calculated as follows:

$$\frac{Actual - Forecast}{ABS(Actual - Forecast)}$$

- Once this is calculated, for each period, the numbers are added to calculate the overall tracking signal. A forecast history entirely void of bias will return a value of zero, with 12 observations, the worst possible result would return either +12 (under-forecast) or -12 (over-forecast). Such a forecast history returning a value greater than 4.5 or less than negative 4.5 would be considered out of control.

At Arkieva (http://www.arkieva.com/products-we-sell/demand-planning/performance-management/), we use the Normalized Forecast Metric to measure the bias. The formula is very simple.

$$NFM = \frac{(Forecast - Actual)}{(Forecast + Actual)}$$

As can be seen, this metric will stay between -1 and 1, with 0 indicating the absence of bias. Consistent negative values indicate a tendency to under-forecast whereas constant positive values indicate a tendency to over-forecast. Over a 12-period window, if the added values are more than 2,

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we consider the forecast to be biased towards over-forecast. Likewise, if the added values are less than -2, we find the forecast to be biased towards under-forecast.

A forecasting process with a bias will eventually get off-rails unless steps are taken to correct the course from time to time. A better course of action is to measure and then correct for the bias routinely. This is irrespective of which formula one decides to use.

Good supply chain planners are very aware of these biases and use techniques such as triangulation to prevent them. Eliminating bias can be a good and simple step in the long journey to an excellent supply chain.

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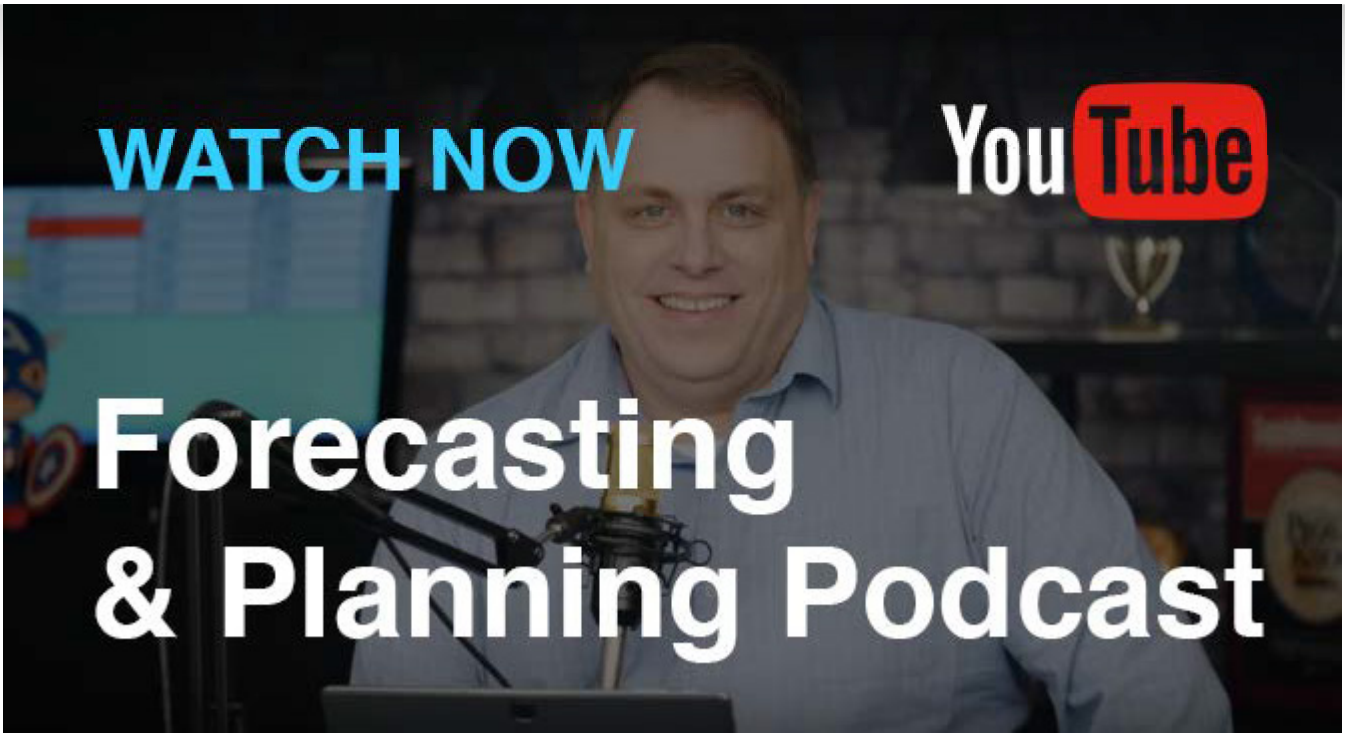
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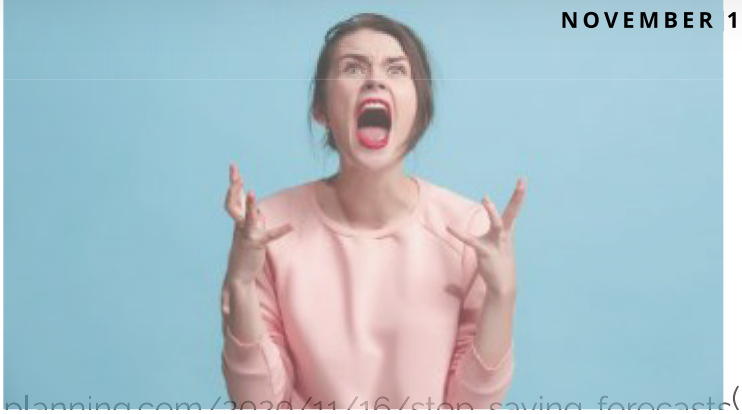
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.T WRWSIHIST 2005011151/
Department of Water Resources
California Cooperative Snow Surveys

Chronological Reconstructed Sacramento and San Joaquin Valley
Water Year Hydrologic Classification Indices

Based on measured unimpaired runoff (in million acre-feet), subject to revision.
*** See explanatory notes at bottom ***

	Sacramento Valley					San Joaquin Valley				
	Runoff (maf)			WY Index		Runoff (maf)			WY Index	
WY	Oct-Mar	Apr-Jul	WYsum	Index	Yr-type	Oct-Mar	Apr-Jul	WYsum	Index	Yr-type
1901						3.49	5.58	9.39	4.60	W
1902						1.12	3.81	5.08	3.41	AN
1903						1.45	4.13	5.71	3.45	AN
1904						1.96	5.37	7.64	4.31	W
1905						1.82	3.36	5.30	3.24	AN
1906	12.57	12.92	26.71	11.76	W	2.53	9.24	12.43	6.70	W
1907	18.96	13.45	33.70	14.07	W	3.67	7.61	11.82	6.20	W
1908	8.29	5.60	14.77	7.73	BN	0.98	2.17	3.32	2.40	D
1909	20.61	8.98	30.68	12.10	W	2.85	5.91	8.97	4.59	W
1910	13.12	6.11	20.12	9.38	W	2.87	3.62	6.64	3.65	AN
1911	12.27	13.12	26.38	11.74	W	3.63	7.52	11.48	5.97	W
1912	4.84	5.65	11.41	6.71	BN	0.54	2.57	3.21	2.55	BN
1913	5.72	6.29	12.85	6.24	D	0.44	2.34	3.00	2.00	C
1914	16.72	10.08	27.81	10.92	W	2.72	5.67	8.69	4.35	W
1915	11.41	11.42	23.86	10.99	W	1.29	4.95	6.40	4.10	W
1916	14.25	8.89	24.14	10.83	W	2.67	5.50	8.38	4.65	W
1917	7.25	9.14	17.26	8.83	AN	1.66	4.84	6.66	4.13	W
1918	5.27	4.89	10.99	6.19	D	1.07	3.40	4.59	3.08	BN
1919	8.12	6.77	15.66	7.00	BN	1.06	2.99	4.09	2.62	BN
1920	3.63	4.91	9.20	5.15	C	0.72	3.29	4.09	2.64	BN
1921	15.47	7.52	23.80	9.20	AN	1.97	3.84	5.90	3.23	AN
1922	6.63	10.57	17.98	8.97	AN	1.51	5.99	7.68	4.54	W
1923	6.21	6.27	13.21	7.06	BN	1.39	3.95	5.51	3.55	AN
1924	3.27	1.94	5.74	3.87	C	0.45	1.03	1.50	1.42	C
1925	8.76	6.51	15.99	6.39	D	1.45	3.93	5.51	2.93	BN
1926	6.37	4.79	11.76	5.75	D	0.89	2.56	3.49	2.30	D
1927	14.34	8.75	23.83	9.52	W	1.80	4.56	6.50	3.56	AN
1928	10.24	5.86	16.76	8.27	AN	1.69	2.64	4.37	2.63	BN
1929	4.00	3.84	8.40	5.22	C	0.52	2.29	2.84	2.00	C
1930	8.24	4.65	13.52	5.90	D	0.76	2.44	3.25	2.02	C
1931	3.52	2.09	6.10	3.66	C	0.46	1.18	1.66	1.20	C
1932	6.28	6.24	13.12	5.48	D	1.79	4.69	6.63	3.41	AN
1933	3.73	4.66	8.94	4.63	C	0.49	2.77	3.34	2.44	D
1934	5.68	2.45	8.63	4.07	C	0.98	1.26	2.28	1.44	C
1935	6.27	9.69	16.59	6.98	BN	1.26	5.03	6.41	3.56	AN
1936	10.32	6.41	17.35	7.75	BN	2.00	4.38	6.49	3.74	AN
1937	5.50	7.24	13.33	6.87	BN	1.78	4.66	6.53	3.90	W
1938	17.96	12.93	31.83	12.62	W	3.58	7.33	11.24	5.89	W
1939	4.56	3.04	8.18	5.58	D	1.00	1.83	2.90	2.20	D
1940	14.78	6.93	22.43	8.88	AN	2.49	4.04	6.59	3.36	AN
1941	16.32	9.77	27.08	11.47	W	2.22	5.51	7.93	4.43	W
1942	14.33	9.93	25.24	11.27	W	1.93	5.28	7.38	4.44	W
1943	13.37	6.90	21.13	9.77	W	2.86	4.28	7.28	4.03	W
1944	4.81	4.93	10.43	6.35	D	0.87	2.97	3.92	2.76	BN
1945	8.42	5.92	15.06	6.80	BN	2.07	4.37	6.60	3.59	AN
1946	10.89	5.97	17.62	7.70	BN	1.99	3.65	5.73	3.30	AN
1947	5.90	3.83	10.39	5.61	D	1.26	2.12	3.42	2.18	D
1948	5.39	9.55	15.75	7.12	BN	0.56	3.58	4.21	2.70	BN
1949	5.73	5.59	11.97	6.09	D	0.62	3.12	3.79	2.53	BN
1950	7.01	6.72	14.44	6.62	BN	1.02	3.57	4.65	2.85	BN
1951	16.77	5.42	22.95	9.18	AN	4.35	2.83	7.25	3.14	AN
1952	13.86	13.68	28.60	12.38	W	2.18	6.84	9.30	5.17	W
1953	10.84	8.26	20.09	9.55	W	1.07	3.18	4.35	3.03	BN
1954	9.74	6.81	17.43	8.51	AN	1.10	3.16	4.30	2.72	BN
1955	5.19	5.07	10.98	6.14	D	0.78	2.67	3.50	2.30	D
1956	20.32	8.60	29.89	11.38	W	4.14	5.29	9.67	4.46	W
1957	7.72	6.29	14.89	7.83	AN	1.02	3.19	4.29	3.01	BN
1958	16.37	12.24	29.71	12.16	W	1.67	6.40	8.36	4.77	W
1959	7.40	3.84	12.05	6.75	BN	0.98	1.85	2.98	2.21	D
1960	7.72	4.65	13.06	6.20	D	0.85	2.07	2.96	1.85	C
1961	6.87	4.39	11.97	5.68	D	0.54	1.50	2.10	1.38	C
1962	8.17	6.23	15.11	6.65	BN	1.26	4.24	5.61	3.07	BN
1963	12.01	10.09	22.99	9.63	W	1.68	4.37	6.24	3.57	AN
1964	5.90	4.37	10.92	6.41	D	0.93	2.14	3.14	2.19	D
1965	16.59	8.13	25.64	10.15	W	3.20	4.55	8.13	3.81	W
1966	7.42	4.84	12.95	7.16	BN	1.49	2.42	3.98	2.51	BN
1967	12.14	11.01	24.06	10.20	W	2.46	7.09	9.98	5.25	W
1968	8.66	4.12	13.64	7.24	BN	1.02	1.85	2.94	2.21	D
1969	15.33	10.68	26.98	11.05	W	3.84	8.14	12.29	6.09	W
1970	18.87	4.35	24.06	10.40	W	2.55	2.96	5.61	3.18	AN
1971	12.71	8.90	22.57	10.37	W	1.56	3.23	4.91	2.89	BN
1972	7.61	5.02	13.43	7.29	BN	1.25	2.22	3.57	2.16	D
1973	12.80	6.38	20.05	8.58	AN	1.87	4.48	6.47	3.50	AN
1974	21.69	9.78	32.50	12.99	W	2.43	4.53	7.12	3.90	W
1975	9.24	8.95	19.23	9.35	W	1.37	4.65	6.18	3.85	W
1976	4.63	2.75	8.20	5.29	C	0.78	1.07	1.97	1.57	C
1977	2.49	1.93	5.12	3.11	C	0.22	0.80	1.05	0.84	C
1978	14.90	8.12	23.92	8.65	AN	2.57	6.50	9.65	4.58	W
1979	6.06	5.64	12.41	6.67	BN	1.87	3.99	5.98	3.67	AN
1980	15.49	6.00	22.33	9.04	AN	3.74	5.41	9.47	4.73	W
1981	6.81	3.63	11.10	6.21	D	0.85	2.29	3.22	2.44	D
1982	20.56	11.82	33.41	12.76	W	3.78	7.00	11.41	5.45	W
1983	22.75	13.66	37.68	15.29	W	5.42	8.73	15.01	7.22	W
1984	15.98	5.52	22.35	10.00	W	3.51	3.48	7.13	3.69	AN
1985	6.24	4.00	11.04	6.47	D	1.11	2.41	3.60	2.40	D
1986	19.45	5.45	25.83	9.96	W	4.36	4.92	9.50	4.31	W
1987	5.85	2.80	9.27	5.86	D	0.55	1.48	2.08	1.86	C
1988	5.78	2.90	9.23	4.65	C	0.86	1.55	2.48	1.48	C
1989	9.03	5.07	14.82	6.13	D	1.07	2.42	3.56	1.96	C
1990	4.94	3.72	9.26	4.81	C	0.83	1.59	2.46	1.51	C
1991	3.90	4.01	8.44	4.21	C	0.56	2.57	3.20	1.96	C
1992	5.41	2.93	8.87	4.06	C	0.86	1.66	2.58	1.56	C
1993	12.44	8.98	22.21	8.54	AN	2.49	5.65	8.38	4.20	W
1994	4.55	2.73	7.81	5.02	C	0.66	1.80	2.54	2.05	C
1995	19.83	13.60	34.55	12.89	W	3.67	8.01	12.32	5.95	W

1996	13.05	8.37	22.29	10.26	W	2.57	4.51	7.22	4.12	W
1997	20.22	4.39	25.42	10.82	W	5.75	3.59	9.51	4.13	W
1998	17.65	12.54	31.40	13.31	W	2.82	7.11	10.43	5.65	W
1999	12.97	7.26	21.19	9.80	W	1.90	3.85	5.91	3.59	AN
2000	12.06	5.96	18.90	8.94	AN	1.98	3.78	5.90	3.38	AN
2001	5.64	3.46	9.81	5.76	D	0.92	2.23	3.18	2.20	D
2002	9.32	4.57	14.60	6.35	D	1.27	2.75	4.06	2.34	D
2003	10.71	7.74	19.31	8.21	AN	1.25	3.49	4.87	2.81	BN
2004	10.95	4.40	16.04	7.51	BN	1.51	2.25	3.81	2.21	D
2005	8.40	9.28	18.55	8.49	AN	2.73	6.28	9.21	4.75	W
2006	18.06	13.09	32.09	13.20	W	2.86	7.37	10.44	5.90	W
2007	6.59	3.04	10.28	6.19	D	0.99	1.46	2.51	1.97	C
2008	5.90	3.82	10.28	5.16	C	0.99	2.45	3.49	2.06	C
2009	7.05	5.30	13.02	5.78	D	1.51	3.35	4.94	2.72	BN
2010	7.45	7.78	16.01	7.08	BN	1.43	4.53	6.08	3.55	AN
2011	12.68	11.53	25.21	10.54	W	3.68	6.90	10.99	5.58	W
2012	5.69	5.46	11.84	6.89	BN	0.83	1.86	2.76	2.18	D
2013	8.52	3.01	12.19	5.83	D	1.33	1.67	3.05	1.71	C
2014	4.29	2.59	7.46	4.07	C	0.46	1.21	1.72	1.16	C
2015	6.91	1.77	9.23	4.00	C	0.67	0.74	1.44	0.81	C
2016	12.24	4.60	17.48	6.71	BN	2.03	2.98	5.06	2.35	D
2017	26.17	10.69	37.82	14.14	W	6.65	7.77	14.84	6.46	W
2018	7.09	5.05	12.86	7.14	BN	1.64	3.01	4.76	3.03	BN
2019	13.11	10.66	24.77	10.34	W	2.64	6.34	9.28	4.94	W
min	2.49	1.77	5.12	3.11		0.22	0.74	1.05	0.81	
mean	10.75	6.29	17.85	8.05		1.94	3.73	5.84	3.24	
max	26.17	13.68	37.82	15.29		6.65	9.24	15.01	7.22	

1966-2015 mean

Eight River Runoff [maf]

WY	Dec	Jan	Feb	Mar	Apr	May
1901						
1902						
1903						
1904						
1905						
1906	0.55	3.69	2.93	7.00	5.34	6.43
1907	2.14	2.83	6.01	10.40	7.32	5.86
1908	1.43	2.27	2.12	2.19	2.53	2.59
1909	0.66	11.14	6.85	3.71	4.22	4.78
1910	3.09	2.90	2.55	4.84	4.21	3.30
1911	1.15	4.11	3.61	5.88	6.36	5.71
1912	0.55	1.20	0.94	1.61	1.58	3.33
1913	0.77	1.60	1.01	1.32	2.81	3.31
1914	1.72	8.50	3.99	4.18	5.05	5.28
1915	0.76	1.86	5.43	3.54	4.43	6.38
1916	1.52	3.75	4.89	5.71	5.03	4.44
1917	1.28	1.01	3.13	2.15	4.29	4.37
1918	0.70	0.57	1.22	2.99	3.09	2.53
1919	0.68	1.20	3.13	2.74	3.89	4.06
1920	0.68	0.57	0.58	1.71	2.58	3.20
1921	2.90	4.34	3.15	4.22	3.30	4.01
1922	1.16	1.07	2.63	2.41	3.66	6.68
1923	2.03	1.75	1.20	1.51	3.38	3.66
1924	0.49	0.56	1.16	0.64	1.07	1.10
1925	0.92	0.94	4.99	2.18	3.82	3.70
1926	0.67	0.76	3.18	1.73	3.79	2.18
1927	2.01	2.22	6.05	3.53	4.82	4.28
1928	1.10	1.37	1.94	5.69	3.73	3.02
1929	0.64	0.61	1.12	1.29	1.63	2.49
1930	2.37	1.41	1.84	2.78	2.64	2.29
1931	0.39	0.80	0.78	1.20	1.23	1.18
1932	1.68	1.33	1.84	2.50	2.73	4.16
1933	0.42	0.70	0.58	1.89	1.97	2.36
1934	1.04	1.47	1.59	1.90	1.61	1.09
1935	0.79	1.87	1.56	2.13	6.18	4.74
1936	0.51	3.22	5.04	2.77	3.83	3.71
1937	0.45	0.54	2.36	3.28	3.77	4.92
1938	4.81	1.86	5.27	7.50	5.98	7.34
1939	0.80	0.79	0.81	1.91	2.26	1.47
1940	0.68	3.88	5.68	6.22	4.61	3.77
1941	3.41	4.28	5.07	4.72	4.62	5.75
1942	3.58	4.18	5.10	2.23	4.64	4.76
1943	1.83	4.67	2.84	5.33	4.23	3.59
1944	0.55	0.78	1.44	1.94	1.88	3.34
1945	1.50	1.07	4.13	2.17	2.82	3.82
1946	4.60	2.64	1.31	2.29	3.45	3.68
1947	1.06	0.64	1.57	2.51	2.20	2.05
1948	0.50	1.91	0.70	1.56	4.34	4.51
1949	0.66	0.53	0.92	3.32	3.27	3.39
1950	0.43	1.82	2.54	2.46	3.74	3.73
1951	5.95	3.40	3.52	2.66	2.81	3.15
1952	3.36	3.48	4.03	3.68	6.35	7.51
1953	1.92	5.40	1.52	2.06	3.25	3.38
1954	0.80	2.20	2.84	3.66	4.56	3.27
1955	1.35	1.16	0.96	1.27	1.97	3.22
1956	9.14	7.52	3.71	3.07	3.51	5.24
1957	0.61	0.79	2.65	3.41	2.36	3.85
1958	1.62	2.39	7.61	4.71	6.04	6.74
1959	0.58	2.25	2.50	1.98	2.27	1.82
1960	0.47	0.90	3.15	3.22	2.50	2.39
1961	1.36	0.86	2.14	1.93	2.02	2.16
1962	1.19	0.78	4.08	2.39	3.89	3.14
1963	1.90	1.70	4.66	2.10	5.60	4.99
1964	0.85	1.55	1.01	1.15	1.92	2.44
1965	8.66	5.61	2.26	1.97	4.74	3.81
1966	1.04	1.85	1.56	2.52	3.33	2.52
1967	2.98	3.34	2.52	4.09	3.82	6.26
1968	0.85	1.49	3.71	2.55	2.17	2.15
1969	1.77	7.91	4.73	3.36	5.44	7.34
1970	3.30	10.68	3.02	3.12	1.82	2.77
1971	3.26	3.05	1.83	3.73	3.40	4.18
1972	1.19	1.40	1.73	3.30	2.52	2.61
1973	1.83	4.08	3.66	3.27	3.08	4.76
1974	3.68	6.93	2.10	6.18	5.07	4.69
1975	0.86	1.01	2.92	4.65	2.89	5.40
1976	0.76	0.65	0.88	1.34	1.35	1.44
1977	0.38	0.47	0.48	0.54	0.69	0.91
1978	1.90	5.91	3.48	5.36	4.40	4.70
1979	0.53	1.44	2.10	2.90	2.67	4.50
1980	1.24	6.89	5.93	3.62	3.11	3.67

1981	0.92	1.57	1.76	2.48	2.32	2.11
1982	5.58	3.50	5.57	4.74	8.05	5.68
1983	3.69	4.25	6.46	10.57	4.87	6.96
1984	6.72	2.85	2.29	3.08	2.50	3.60
1985	1.20	0.84	1.21	1.59	2.79	2.14
1986	1.25	2.62	11.55	7.09	3.19	3.56
1987	0.53	0.78	1.48	2.60	1.73	1.48
1988	1.70	1.84	1.01	1.26	1.48	1.59
1989	0.72	0.85	0.99	6.17	3.59	2.22
1990	0.45	1.27	0.88	1.84	1.80	1.77
1991	0.34	0.37	0.45	2.64	1.95	2.40
1992	0.47	0.58	2.41	1.99	2.17	1.33
1993	1.25	4.06	3.13	5.70	4.33	5.23
1994	0.78	0.78	1.23	1.49	1.57	1.79
1995	1.06	8.11	3.12	10.19	5.61	7.18
1996	1.72	2.47	6.25	4.25	3.97	5.50
1997	6.84	12.15	2.74	2.45	2.70	2.96
1998	1.18	5.19	7.44	5.11	4.53	5.53
1999	1.88	2.60	4.59	3.67	3.26	4.27
2000	0.65	2.55	5.49	4.08	3.55	3.62
2001	0.67	0.87	1.50	2.39	2.03	2.49
2002	2.50	2.70	1.74	2.31	2.82	2.60
2003	3.24	3.40	1.66	2.52	3.27	4.82
2004	2.14	1.90	3.98	3.47	2.64	2.29
2005	1.56	2.49	2.01	3.75	3.18	7.23
2006	5.83	5.16	3.42	5.38	8.56	6.84
2007	1.32	0.87	2.14	2.07	1.74	1.67
2008	0.70	1.70	1.81	1.79	1.89	2.68
2009	0.57	0.96	2.32	3.64	2.40	4.21
2010	0.71	2.48	2.31	2.31	3.25	3.70
2011	4.31	2.10	1.96	6.20	5.23	4.94
2012	0.49	0.96	0.74	3.03	3.70	2.27
2013	4.09	1.34	1.08	1.71	2.02	1.43
2014	0.38	0.36	1.22	2.05	1.71	1.18
2015	2.89	0.79	2.23	0.84	0.76	0.82
2016	1.26	3.67	2.10	6.50	2.92	2.53
2017	3.71	8.53	12.65	5.52	6.61	5.84
2018	0.73	1.47	0.81	3.85	4.23	2.13
2019	0.86	2.83	5.20	5.89	6.16	4.97
min	0.34	0.36	0.45	0.54	0.69	0.82
mean	1.92	2.89	2.82	3.54	3.14	3.56
max	9.14	12.15	12.65	10.57	8.56	7.51

1966-2015 mean

Official Year Classifications based on May 1 Runoff Forecasts

	Sacramento Valley Index		San Joaquin Valley Index	
WY	Index	Yr-type	Index	Yr-type
1995	12.4	W	5.5	W
1996	9.7	W	3.9	W
1997	11.0	W	4.2	W
1998	12.4	W	4.9	W
1999	10.0	W	3.4	AN
2000	9.2	W	3.3	AN
2001	5.9	D	2.3	D
2002	6.5	D	2.3	D
2003	8.0	AN	2.7	BN
2004	7.7	BN	2.2	D
2005	7.4	BN	4.2	W
2006	13.0	W	5.5	W
2007	6.2	D	1.9	C
2008	5.4	C	2.1	C
2009	5.5	D	2.4	D
2010	6.9	BN	3.5	AN
2011	10.0	W	5.1	W
2012	6.9	BN	2.2	D
2013	5.8	D	1.6	C
2014	4.0	C	1.1	C
2015	4.0	C	0.7	C
2016	7.1	BN	2.4	D
2017	14.9	W	6.2	W
2018	7.2	BN	3.0	BN
2019	10.2	W	4.2	W

Abbreviations:

WY	Water year (Oct 1 - Sep 30)
W	Wet year type
AN	Above normal year type
BN	Below normal year type
D	Dry year type
C	Critical year type
% exc.	Probability in % that a given value will be exceeded
[maf]	Million acre-feet

Notes:

Unimpaired runoff represents the natural water production of a river basin, unaltered by upstream diversions, storage, export of water to or import of water from other basins.

Sacramento River Runoff is the sum (in maf) of Sacramento River at Bend Bridge, Feather River inflow to Lake Oroville, Yuba River at Smartville, and American River inflow to Folsom Lake. The WY sum is also known as the Sacramento River Index, and was previously referred to as the "4 River Index" or "4 Basin Index". It was previously used to determine year type classifications under State Water Resources Control Board (SWRCB) Decision 1485.

Sacramento Valley Water Year Index = 0.4 * Current Apr-Jul Runoff Forecast (in maf) + 0.3 * Current Oct-Mar Runoff in (maf) + 0.3 * Previous Water Year's Index (if the Previous Water Year's Index exceeds 10.0, then 10.0 is used). This index, originally specified in the 1995 SWRCB Water Quality Control Plan, is used to determine the Sacramento Valley water year type as implemented in SWRCB D-1641. Year types are set by first of month forecasts beginning in February. Final determination is based on the May 1 50% exceedence forecast.

Sacramento Valley Water Year Hydrologic Classification:

Year Type:	Water Year Index:
Wet	Equal to or greater than 9.2
Above Normal	Greater than 7.8, and less than 9.2
Below Normal	Greater than 6.5, and equal to or less than 7.8
Dry	Greater than 5.4, and equal to or less than 6.5
Critical	Equal to or less than 5.4

San Joaquin River Runoff is the sum of Stanislaus River inflow to New Melones Lake, Tuolumne River inflow to New Don Pedro Reservoir, Merced River inflow to Lake McClure, and San Joaquin River inflow to Millerton Lake (in maf).

San Joaquin Valley Water Year Index = 0.6 * Current Apr-Jul Runoff Forecast (in maf)

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   + 0.2 * Current Oct-Mar Runoff in (maf) + 0.2 * Previous Water Year's Index
   (if the Previous Water Year's Index exceeds 4.5, then 4.5 is used).
   This index, originally specified in the 1995 SWRCB Water Quality Control Plan,
   is used to determine the San Joaquin Valley water year type as implemented in
   SWRCB D-1641.  Year types are set by first of month forecasts beginning in
   February.  Final determination for San Joaquin River flow objectives is based
   on the May 1 75% exceedence forecast.
San Joaquin Valley Water Year Hydrologic Classification:
    Year Type:      Water Year Index:
    Wet             Equal to or greater than 3.8
    Above Normal    Greater than 3.1, and less than 3.8
    Below Normal    Greater than 2.5, and equal to or less than 3.1
    Dry             Greater than 2.1, and equal to or less than 2.5
    Critical        Equal to or less than 2.1
Eight River Index = Sacramento River Runoff + San Joaquin River Runoff
   This Index is used from December through May to set flow objectives
   as implemented in SWRCB Decision 1641.

The 'reconstructed' table is based on observed runoff, and does NOT show the
   official year-types, which are based on May 1 forecasts of future runoff.
The current water year indices based on forecast runoff are posted at
   http://cdec.water.ca.gov/water_supply.html and published in DWR Bulletin 120
   (also available at http://cdec.water.ca.gov/snow/bulletin120)
These indices have been used operationally since 1995, and are defined in SWRCB
   Decision 1641
   (https://www.waterboards.ca.gov/waterrights/water_issues/programs/bay_delta/decision_1641/)
This report is updated each fall once the data is available.

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company to Revise its Electric Marginal Costs, Revenue Allocation, and Rate Design. (U 39 M)	Application 16-06-013 (Filed June 30, 2016)

PACIFIC GAS AND ELECTRIC COMPANY'S (PG&E) AGRICULTURAL BALANCING ACCOUNT STUDY WITH AGRICULTURAL PARTIES' ADDENDUM

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Dated: September 23, 2016

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company to Revise its Electric Marginal Costs, Revenue Allocation, and Rate Design. (U 39 M)	Application 16-06-013 (Filed June 30, 2016)

PACIFIC GAS AND ELECTRIC COMPANY'S (PG&E) AGRICULTURAL BALANCING ACCOUNT STUDY WITH AGRICULTURAL PARTIES' ADDENDUM

In compliance with Decision (D.) 15-08-005, Pacific Gas and Electric Company (PG&E) hereby provides the California Public Utilities' Commission (Commission or CPUC) and all parties to its 2017 General Rate Case (GRC) Phase II proceeding (Application 16-06-013), the Agricultural Balancing Account Study (AG Report), with Addendum from agricultural parties.

This filing also complies with the August 30, 2016 letter from Timothy Sullivan, the CPUC's Executive Director, granting PG&E's request for a scheduling extension to serve the AG Report, in order to allow intervenors who wished to include their own comments, as an addendum to this Report. The AG Report and Addendum filed herewith constitute Appendix F to Exhibit (PG&E-1), Prepared Testimony, Volume 2.

Respectfully submitted,

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Dated: September 23, 2016

APPENDIX F

(As Filed in Exhibit 1)

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX F

AGRICULTURAL CLASS BALANCING ACCOUNT STUDY

PACIFIC GAS AND ELECTRIC COMPANY
APPENDIX F
AGRICULTURAL CLASS BALANCING ACCOUNT STUDY

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PACIFIC GAS AND ELECTRIC COMPANY
APPENDIX F
AGRICULTURAL CLASS BALANCING ACCOUNT STUDY

A. Introduction

In the Marginal Cost and Revenue Allocation Settlement (the Settlement) approved by Decision 15-08-005, the California Public Utilities Commission (CPUC or Commission) approved an Agricultural Class Balancing Account Study. The description of the study as set forth in the Settlement is provided:

> A balancing account or other mechanism that addresses the high level of sales variability and sales forecast uncertainty pertaining to the agricultural class, principally as a result of the unpredictability of the availability of surface water, will not be established as part of this Settlement. Instead, parties agree to pursue additional analyses to examine the desirability of such a balancing account, and the necessary components to develop it. Such analyses would review the year-to-year volatility of agricultural class revenues and sales versus other customer class revenues and sales, and include an assessment of possible over-collections of agricultural class revenue that accounts for variation in both PG&E's cost of service and revenues collected due to agricultural sales variability.
>
> PG&E will compile an initial set of data based on input the parties provide to PG&E during the first quarter of 2015, and will provide that data to interested parties, to the extent feasible, for review at least two weeks prior to a workshop at which the data will be discussed. At the workshop, which is to be held no later than 9 months prior to the next GRC Phase II application deadline (and which may be held earlier), the parties will review the available data, provide input with regard to the required analysis, and establish a schedule for completion of the analysis and a workshop report. The schedule will set a date by which PG&E will complete and provide to all parties a report memorializing the analysis, which is targeted to be provided to interested parties no later than 6 months prior to the filing of PG&E's next GRC Phase II application (and which may be provided earlier). The schedule will also include a second workshop at least two weeks following distribution of the report, at which parties will have the opportunity to ask questions about the report and discuss PG&E's analysis and conclusions. The schedule will afford parties an opportunity to provide their own evaluation of the analysis, to be transmitted to PG&E within 6 weeks of service of the initial report, such that evaluations by the parties can be included with the report. The parties envision the completion of the whole agricultural balancing account analysis process by no later than 4 months in advance of the deadline for PG&E's 2017 GRC Phase II application. The report will be included as a compliance item attached to PG&E's next GRC Phase II application.

In response to Pacific Gas and Electric Company's (PG&E) request for data requirements, Agricultural Parties[1] and the California Large Energy Consumers Association (CLECA) provided requests for information. PG&E responded to the Agricultural Parties request on September 4, 2015, and to CLECA's request on September 11, 2015. A summary of these data requests is provided as Attachment 1 to this Appendix. PG&E held the first workshop specified by the Settlement on September 22, 2015.[2] The notice regarding the availability of the Draft Report was issued on November 30, 2015.[3] Comments on the Draft Report were received from the Agricultural Parties on December 14, 2015.[4] PG&E issued a revised Draft Report on December 17, 2015, which provided non-substantive edits to the original Draft Report primarily to ensure common use of terms in preparation for the second workshop.[5] The second required workshop was held December 21, 2015.[6] During the workshop, the parties requested a summary be prepared of the discussion. PG&E prepared a draft summary and requested comments on the summary. The summary of the second workshop is incorporated into Section C below.

B. Workshop 1, September 22, 2015

On September 22, 2015, PG&E held the first workshop on the AG Balancing Account Study. Southern California Edison Company (SCE), AECA, CLECA, CFBF and PG&E participated in the workshop. PG&E's presentation, as well as the presentation made by AECA, is attached to this Report as Attachment 3. Three additional areas of work were discussed during the meeting for consideration in the Report.

1. Average rate variability was not mentioned during PG&E's presentation and should be included in the study. PG&E agrees with this observation and has incorporated that work into this study.

---

1 Agricultural Parties include California Farm Bureau Federation (CFBF) and Agricultural Energy Consumers Association (AECA).

2 Required notice was provided for the first workshop on August 31, 2015.

3 By the Executive Director's letter dated November 6, 2015, the due date of the draft Study was extended to November 30, 2015.

4 Comments from CLECA were also received verbally.

5 A list of terms is provided as Attachment 2 to this Report.

6 Required notice for the second workshop was provided on December 9, 2015.

2. Actual costs for agriculture for 2014 were requested. As a general matter, very few utility costs are recorded by customer class. The exception would be some portion of customer-related costs that are often captured by rate schedule. As such, there is no way to produce an 'actual' accounting of cost by rate schedule.
3. PG&E was requested to provide an approach to address under or over-collections that may be identified by this Report.

C. Workshop 2, December 21, 2015

PG&E, the Office of Ratepayer Advocates (ORA), CLECA, CFBF, SCE and AECA participated in the second Agricultural Class Balancing Account Workshop on December 21, 2015.

PG&E introduced the second workshop as an opportunity to ask questions about the Draft Report prepared by PG&E. Prior to the workshop, AECA and CFBF provided comments on the Draft Report. PG&E discussed these comments with AECA and CFBF prior to the workshop, and briefly reviewed that discussion with the parties. In brief, AECA and CFBF felt that while Tables 4 and 5 of the Draft Report were a good start, the following tables (Tables 6 to 11), which were intended only to reflect the allocation of a change in systemwide revenue requirement based on the current allocation rules (i.e., using the actual revenue allocation in a given year), needed to be revised to also reflect the change in that year's revenue allocation that would ensue from using an underlying General Rate Case (GRC) Phase II revenue allocation that reflected perfect forecast conditions. The parties also were concerned that the latter set of tables did not use the same years (2011 and 2013) as the former (2011 and 2014), making comparisons difficult.

In discussing how the "perfect forecast" GRC Phase II revenue allocation might be reflected in the revenue allocation in each year of the GRC cycle, CLECA asked if it would be possible to make an adjustment to agricultural rates each year once water availability becomes known to reflect its impact on forecast agricultural sales. If a revision were determined to be mechanically possible, then a discussion of what adjustments might be fair and reasonable could continue. PG&E tentatively agreed that an adjustment with the following characteristics would be mechanically feasible:

1. A publically acknowledged trigger indicating the level of water availability, and thus greater or reduced water pumping needs, would be known by about mid-March. A specific trigger value would dictate a specific adjustment to agricultural rates that could then be implemented on May 1 by Tier 1 advice letter.
2. The exact nature of the specific adjustment to agricultural rates was not defined; however, higher pumping needs resulting from reduced water availability would result in lower agricultural rates. Similarly, greater water availability, and thus lower agricultural water pumping needs, would lead to higher agricultural rates.
3. The adjustment to agricultural rates would need to be transparent and non-controversial to enable implementation via a Tier 1 advice letter.
4. The adjustment would impact only agricultural rates and would not affect rates for any other class.
5. The adjustment and PG&E's forecast need to be in sync. That is, if the forecast already implied a year of scarce water availability, a duplicative adjustment to agricultural rates would not be appropriate.

AECA and CFBF indicated that water delivery allocations are usually announced by mid-March by the State Water Project and Central Valley Project. These would provide the trigger on forecasting agricultural demand for the coming summer.

None of the parties objected to investigating the adjustment described above, but ORA, CLECA, AECA, and CFBF indicated that further detail was required before any agreement could be reached. With the understanding that an adjustment to rates might be feasible, PG&E agreed to look into whether a "perfect-forecast"-based allocation could be completed on a consistent basis for the period 2011 through 2014 for generation and distribution revenue. This analysis would be used to determine what adjustments might be appropriate.

D. Sales and Average Rate Variability

1. Sales Variability

In **Table 1** of Attachment 4, the total sales forecast and the total actual sales are compared for the period beginning 1995. The classes used for this comparison are categorized by Revenue Account and comprise 98 to

99 percent of the total forecast sales each year. The comparison by Revenue Account is used because sales are actually forecasted by revenue account. As discussed at the time the study was formulated, the agricultural class has demonstrated significantly more sales variability relative to forecast than have other customer classes.

The most impacted years where total agricultural sales were forecasted at levels less than actual were 2008, 2009, 2013 and 2014. In general, years where there was a forecast of levels greater than actual indicated less variation relative to the total agricultural forecast sales and occurred in 2005 and 2011.

2. Average Rate Variability

The purpose of this analysis was to compare the bundled forecast and bundled actual average rate by customer class. PG&E's sales forecast each year is determined in the Energy Resource Recovery Account (ERRA) proceeding and is used to set rates in the following year. In addition to the overall forecast of agricultural sales developed in the ERRA proceeding, the forecast average rate depends on the estimate of individual billing determinants for each rate schedule. For example, the forecast average rate would be a function of estimated sales by Time-of-Use (TOU) period, customer months, maximum or connected demand, and where relevant, demand by TOU period. These forecast billing determinants are derived based on average recorded data for each class (using three years of recorded data for Agricultural schedules and one year for other schedules). Forecast billing determinants when applied to forecast sales and current rates determines the estimate of revenue at present rates from which class average rates are derived.

Table 2 of Attachment 4 includes a comparison of the bundled average agricultural rate (forecast and actual) to the system average bundled rate (forecast and actual). Because of the variation in agricultural average rates (forecast compared to actual), PG&E made a comparison of the bundled average rates for all customer groups from 2005 through 2014. **Table 3** of Attachment 4 provides a comparison of average bundled rates for all customer groups. For bundled average forecast rates, PG&E used January 1 (Annual Electric True-Up) rates for each year. In the Agricultural

Class, AG-ICE revenue is separately identified in recorded information, but is not forecast. The Standby and AG-A populations demonstrate the most variation in bundled average rate in every year.

E. Generation and Distribution Cost of Service

As a result of comments regarding PG&E's draft report, PG&E agreed to look into developing cost of service on a consistent basis for the period 2011 through 2014 for generation and distribution revenue. This section of the report deals with that assessment. The purpose of this review is to determine the impact of variation of actual agricultural sales compared to forecast as those differences could affect the allocation of cost to the agricultural class. Since PG&E's forecast of sales is the basis for determining the rates charged to customers and by extension the actual billed revenue, this comparison can be made by a comparison of the actual billed revenue to the revenue that would have otherwise been allocated to customers and billed if a full cost-based allocation was performed each year.

PG&E analyzed the generation and distribution cost of service by preparing a cost-based revenue allocation to the class as if they were prepared for a GRC Phase II proceeding. However, for this comparison, PG&E developed the revenue allocation for specified years utilizing assumptions for the actual year (i.e., a perfect forecast) and compared those results with the actual billed revenue. This comparison focuses on distribution and generation allocations of cost since those are the costs driven by the marginal cost ratemaking in the Phase II proceedings. PG&E has evaluated the period from 2011 (a relatively wet year where forecast agricultural sales lower than forecast) through 2014 (a drought year where total agricultural sales were significantly higher than forecast) for purposes of the analysis.

1. Generation Allocation

Generation revenue is allocated to each customer class based on its share of marginal cost revenue. Generation marginal cost revenue is fundamentally comprised of two parts. First, marginal generation capacity cost revenue is determined by multiplying a generation marginal capacity cost by Peak Cost Allocation Factors (PCAF), which are estimates of each customer class's contribution to the system peak hours. The second portion

of generation marginal cost is marginal energy costs (MEC). MECs are determined for each time period and then multiplied by the TOU sales for each class to determine the MEC revenue. The sum of generation marginal capacity cost revenue and MEC revenue are the total generation marginal cost revenue for the class. Total generation revenue is then allocated to each customer class in proportion to its share of marginal cost revenue. This approach is known as the Equal Percent of Marginal Cost (EPMC) method.

Typically in GRC Phase II proceedings, recorded base year data is used to develop cost of service for the forecasted test year. For this analysis, however, actual data for sales and PCAFs were available for each year to allow a full study based on the actual sales and loads for each year, effectively permitting a forecast equal to actual sales in the test year. To develop the cost of service for each year, PG&E used PCAFs from 2011 for 2011, PCAFs from 2012 for 2012, PCAFs for 2013 for 2013, and PCAFs from 2014 for 2014. Similarly, actual total sales from each year were used as the forecast for that same year.[7]

PG&E first conducted the analysis for all four years using PG&E's proposed generation marginal costs as presented in its 2014 GRC Phase 2 proceeding as shown in Table F-1 below. The subsequent Tables F-2 through F-6 are based on this 2014 GRC marginal cost. However, PG&E has also conducted the analysis based on its proposed 2011 GRC marginal generation costs as described below.

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7 Total billed sales were used for the analysis. Usage by TOU period and PCAFs are based on the Load Research Study results for each year.

TABLE F-1
2014 MARGINAL GENERATION COSTS

Line No.		Marginal Energy Costs ($/kWh)		
		Transmission	Primary	Secondary
1	Summer On Peak	$0.05613	$0.05718	$0.06001
2	Summer Part Peak	$0.04791	$0.04881	$0.05123
3	Summer Off Peak	$0.03654	$0.03722	$0.03907
4	Winter Part Peak	$0.04856	$0.04948	$0.05192
5	Winter Off Peak	$0.03968	$0.04043	$0.04243
		Generation Marginal Capacity Cost ($/kW-year) including 15% Reserve Adder		
		Transmission	Primary	Secondary
6	Average Cost	$65.65	$67.58	$71.63

Next, generation marginal cost revenues were derived for each year using the marginal costs from Table F-1 and recorded sales and loads. The marginal cost revenue divided by the bundled sales is equal to the average marginal cost. Table F-2, below, shows the average generation marginal cost revenue for capacity and energy.

TABLE F-2
AGRICULTURAL CLASS GENERATION MARGINAL COST OF SERVICE

Line No.		Recorded Bundled Sales	Average Capacity MC	Average Energy MC	Total Average MC	Total Marginal Cost Revenue
		(GWh)	($/kWh)	($/kWh)	($/kWh)	($M)
1	2011	4,654	0.01854	0.04520	0.06373	297
2	2012	6,140	0.01711	0.04517	0.06228	382
3	2013	6,984	0.01434	0.04508	0.05942	415
4	2014	7,582	0.01422	0.04584	0.06006	455

PG&E reviewed the cost drivers for cost of service calculation. As discussed above, the cost drivers were generation PCAFs and usage by TOU period. Generation PCAFs are expressed below as the agricultural percentage share of systemwide PCAFs in each year. As generally supporting the higher PCAF shares over time, PG&E notes that the agricultural peak period usage has increased relative to other customer groups over time (Table F-3, Column (5) below). However, as noted in

Table F-2, the average generation marginal cost has declined as a result of higher load factor (noted in Table F-3, Column (4) below).

TABLE F-3
AGRICULTURAL CLASS GENERATION CAPACITY COST DRIVERS

Line No.		Generation PCAF	System Generation PCAF Share	Bundled Sales	kWh/ PCAF-kW	Ratio of Agricultural Peak Sales to Total Peak Sales
		(MW)		(GWh)	(hrs)	
		(1)	(2)	(3)	(4)	(5)
1	2011	1,259	7.46%	4,654	3,696	6.20%
2	2012	1,532	9.32%	6,140	4,007	8.02%
3	2013	1,453	8.23%	6,984	4,808	9.19%
4	2014	1,505	9.05%	7,582	5,037	10.13%

TABLE F-4
AGRICULTURAL CLASS GENERATION ENERGY COST DRIVERS

Line No.		Summer			Winter		Annual
		On Peak	Part Peak	Off Peak	Part Peak	Off Peak	Total
		(%)	(%)	(%)	(%)	(%)	(%)
1	2011	12.5%	14.3%	37.4%	14.9%	20.9%	100.0%
2	2012	12.3%	14.4%	37.5%	14.9%	20.9%	100.0%
3	2013	11.0%	15.4%	37.8%	15.6%	20.2%	100.0%
4	2014	11.7%	14.5%	38.5%	14.7%	20.5%	100.0%

PG&E determined the total cost allocation for each year based on the marginal cost revenue for each year, using 2014 marginal costs throughout. This allocated revenue is the target level of revenue for the class adjusted for the EPMC multiplier. The target revenue is determined by multiplying the total billed generation revenue for the year by the agricultural class share of marginal cost revenue.

TABLE F-5
ALLOCATED GENERATION REVENUE

Line No.		Agricultural Class Generation Marginal Cost ($M)	Total Generation Marginal Cost ($M)	Agricultural Marginal Cost Share (%)	Total Billed Generation Revenue ($M)	Allocated Agricultural Generation Revenue ($M)
1	2011	297	4,653	6.37%	5,843	372
2	2012	382	4,680	8.17%	5,545	453
3	2013	415	4,754	8.73%	6,194	541
4	2014	455	4,617	9.86%	6,740	665

As a final step, the actual agricultural billed revenue is compared to the allocated revenue in the table below.

TABLE F-6
COMPARISON OF GENERATION ALLOCATED VERSUS BILLED REVENUE

Line No.		Allocated Agricultural Generation Revenue ($M)	Allocated Agricultural Generation Average Rate ($/kWh)	Agricultural Billed Generation Revenue ($M)	Agricultural Billed Generation Average Rate ($/kWh)	Generation Revenue Difference ($M)	Average Generation Rate Difference (%)
1	2011	372	$0.08005	334	$0.07173	(39)	(10.38)%
2	2012	453	$0.07379	425	$0.06922	(28)	(6.18)%
3	2013	541	$0.07742	502	$0.07189	(39)	(7.14)%
4	2014	665	$0.08768	601	$0.07925	(64)	(9.61)%

The step by step calculation provided in tables shown above is summarized in Table 1 of Attachment 5. PG&E next repeated the analysis using 2011 marginal costs for all four years: 2011 through 2014. These results are summarized in Table 2 of Attachment 5. PG&E's proposed 2011 generation marginal costs are shown in Table F-7, below.

TABLE F-7
2011 MARGINAL GENERATION COSTS

Line No.		Marginal Energy Costs ($/kWh)		
		Transmission	Primary	Secondary
1	Summer On Peak	$0.04945	$0.05109	$0.05356
2	Summer Part Peak	$0.04632	$0.04780	$0.04919
3	Summer Off Peak	$0.03441	$0.03524	$0.03592
4	Winter Part Peak	$0.04512	$0.04633	$0.04859
5	Winter Off Peak	$0.03567	$0.03649	$0.03721
		Generation Marginal Capacity Cost ($/kW-year) including 15% Reserve Adder		
		Transmission	Primary	Secondary
6	Average Cost	$105.48	$108.97	$114.24

2. Distribution Allocation

Distribution revenue is also allocated to each customer class based on its share of marginal cost revenue. Distribution marginal cost revenue is comprised of two parts. The first part is distribution marginal customer access costs (MCAC) and the second part is the marginal distribution capacity cost (MDCC) portion of the rate. MCAC revenue is determined by multiplying the MCAC by the number of customers in the year. MDCC revenue is a function of two different kinds of distribution costs. The first kind are those which vary by time of day, or are time varying. For these costs, the marginal cost revenue is determined by multiplying a distribution PCAF by the primary MDCC. For the second type of cost which is not time varying, marginal cost revenue is determined by multiplying the new business primary MDCC and secondary MDCC by final line transformer (FLT) demand. The sum of distribution MCAC and the two types of MDCC revenues is the total distribution marginal cost revenue for the class. Total distribution revenue is then allocated to each customer class in proportion to its share of marginal cost revenue consistent with the EPMC method.

As for generation described above, typically in GRC Phase II proceedings, recorded base year data is used to develop cost of service for the forecasted test year. For this analysis, however, actual data was available for each year to allow a full study based on the actual customers, sales and loads for each year, effectively permitting a forecast equal to actual sales for the test year. To develop the cost of service for each year,

PG&E developed and used distribution PCAFs from 2011 for 2011, PCAFs from 2012 for 2012, PCAFs for 2013 for 2013, and PCAFs from 2014 for 2014. Similarly, actual final line transformer demands from each year were used as the forecast for that same year.[8] Finally, PG&E used actual customer months for each year.

For purposes of this analysis, PG&E has not altered the distribution marginal capacity costs ($/kW FLT or $/kW PCAF) since these factors do not vary by customer class.[9] In addition, PG&E has not changed the MCAC from year to year.[10] PG&E first conducted the analysis for all four years using its proposed 2014 marginal costs, shown in Table F-8 below.[11] The subsequent Tables F-9 through F-12 are based on 2014 marginal costs. However, PG&E has also conducted the analysis based on its proposed 2011 marginal distribution costs as described below.

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8 Total billed sales were used for the analysis. Usage by TOU period and PCAFs are based on the Load Research Study results for each year.

9 While MDCC unit costs are the same for all customer groups, the average cost for a customer group can vary because these costs vary geographically.

10 MCAC can be determined by either the Rental Method or the New Customer Only (NCO) Method. The values used in this analysis were based on the NCO method, which is the approach PG&E has proposed in past GRCs. MCAC based on the NCO method can vary significantly for a single customer class because it is dependent on the number of forecast new connections for the group. Therefore, with substantially increasing or decreasing numbers of customers, the NCO method would result in a different unit MCAC. Because there is significant disagreement with regard to the merits of the NCO methodology, PG&E has not attempted to re-estimate the MCAC for customers based on the actual number of new connections from year to year.

11 The MDCC are derived and used in the revenue allocation process at the division level. They are summarized for comparison in Table 8 at the system level.

TABLE F-8
2014 MARGINAL DISTRIBUTION COSTS

Line No.		
	Marginal Capacity Costs ($/kW-year)	
1	Primary Distribution	$37.33
2	Secondary Distribution	$2.33
3	New Business	$11.26
	Marginal Customer Cost ($/Customer-month)	
4	Residential	$6.14
5	Agricultural A	$26.83
6	Agricultural B	$121.45
7	Small L&P	$26.95
8	A10 Medium L&P Secondary	$53.20
9	A10 Medium L&P Primary	$159.77
10	E19 Secondary	$62.34
11	E19 Primary	$524.08
12	E19 Transmission	$554.17
13	E20 Secondary	$463.31
14	E20 Primary	$557.35
15	E20 Transmission	$554.96
16	Streetlights	$6.92
17	Traffic Control	$8.83

Next, marginal cost distribution revenues were derived for each year. The marginal cost revenue divided by the bundled sales is equal to the average marginal cost. Table F-9, below, shows the separate components for each MDCC and MCAC revenue type for the Agricultural class.

TABLE F-9
AGRICULTURAL CLASS DISTRIBUTION MARGINAL COST OF SERVICE

Line No.		Recorded Bundled & DA/CCA Sales	Average Primary MC	Average Secondary MC	Average New Business MC	Subtotal Average MC	Average Customer MC	Total Average MC	Total Marginal Cost Revenue
		(GWh)	($/kWh)	($/kWh)	($/kWh)	($/kWh)	($/kWh)	($/kWh)	($M)
1	2011	4,691	0.00925	0.00124	0.00644	0.01693	0.01335	0.03027	142
2	2012	6,179	0.00730	0.00105	0.00565	0.01400	0.01031	0.02431	150
3	2013	7,022	0.00823	0.00109	0.00569	0.01501	0.00907	0.02408	169
4	2014	7,611	0.00961	0.00136	0.00627	0.01724	0.00902	0.02626	200

PG&E next reviewed the cost drivers used in the above cost of service calculation. As discussed above, the cost drivers were distribution PCAFs, FLT demand and numbers of customers which are shown in Table F-10, below.

TABLE F-10
AGRICULTURAL CLASS DISTRIBUTION COST DRIVERS

Line No.		Distribution PCAF	Customer-months	Bundled & DA/CCA Sales	FLT	Average Agricultural Primary MDCC[(a)]
		(MW)		(GWh)	(MW)	$/PCAF kW
		(1)	(2)	(3)	(4)	
1	2011	1,530	1,009,599	4,691	3,970	42.64
2	2012	1,576	1,027,533	6,179	3,718	38.05
3	2013	1,616	1,026,492	7,022	4,012	41.20
4	2014	1,760	1,041,669	7,611	4,084	44.01

(a) Average Agricultural Primary MDCC is a weighted average of total Agricultural customers in each of the Divisions.

PG&E determined the Agricultural class's total cost allocation for each year based on the distribution marginal cost revenue for each year as shown in Table F-11. This allocated revenue is the target level of cost for the class. The target revenue is determined by multiplying the total billed distribution revenue for the year by the agricultural class share of marginal cost revenue.

TABLE F-11
ALLOCATED DISTRIBUTION REVENUE

Line No.		Agricultural Class Distribution Marginal Cost	Total Distribution Marginal Cost	Agricultural Marginal Cost Share	Total Billed Distribution Revenue	Allocated Agricultural Distribution Revenue
		($M)	($M)	(%)	($M)	($M)
1	2011	142	1,788	7.95%	3,572	284
2	2012	150	1,824	8.24%	4,012	330
3	2013	169	2,273	7.44%	4,035	300
4	2014	200	1,855	10.77%	3,398	366

As a final step, the recorded agricultural billed revenue is compared to the previously derived allocated revenue in the table below.

TABLE F-12
COMPARISON OF DISTRIBUTION ALLOCATED VERSUS BILLED REVENUE

Line No.		Allocated Agricultural Distribution Revenue ($M)	Allocated Agricultural Distribution Average Rate ($/kWh)	Agricultural Billed Distribution Revenue ($M)	Agricultural Billed Distribution Average Rate ($/kWh)	Distribution Revenue Difference ($M)	Average Distribution Rate Difference (%)
1	2011	284	$0.06050	212	$0.04521	(72)	(25.28)%
2	2012	330	$0.05349	281	$0.04556	(49)	(14.82)%
3	2013	300	$0.04276	300	$0.04270	–	(0.13)%
4	2014	366	$0.04810	306	$0.04020	(60)	(16.42)%

The step by step calculations for the tables shown above is summarized in Table 1 of Attachment 6. PG&E next repeated the analysis using its proposed 2011 marginal costs for all four years: 2011 through 2014. These results are summarized in Table 2 of Attachment 6. The distribution marginal costs used for 2011 through 2014 are shown in Table F-13, below.

TABLE F-13
2011 MARGINAL DISTRIBUTION COSTS

Line No.		
	Marginal Capacity Costs ($/kW-year)	
1	Primary Distribution	$54.86
2	Secondary Distribution	$0.77
3	New Business	$10.25
	Marginal Customer Cost ($/Customer-month)	
4	Residential	$7.64
5	Agricultural A	$42.14
6	Agricultural B	$68.56
7	Small L&P	$33.11
8	A10 Medium L&P Secondary	$136.86
9	A10 Medium L&P Primary	$80.20
10	E19 Secondary	$839.77
11	E19 Primary	$770.98
12	E19 Transmission	$1,335.26
13	E20 Secondary	$993.44
14	E20 Primary	$844.99
15	E20 Transmission	$1,999.29
16	Streetlights	$11.59
17	Traffic Control	$33.11

F. Revenue Allocation for Other Components of Rates

The purpose of this analysis is similar to the analysis of distribution and generation charges. Like those components, the objective is to compare the

actual revenue and the revenue that would have been received if forecasts were perfect, that is if forecasted sales had actually equaled recorded sales. However, unlike distribution and generation, allocation of these costs is not based on marginal cost of service. In addition, all of these remaining components are collected from agricultural customers based on sales (i.e., $/kWh).[12] To study these components, PG&E utilized the same approach it used to allocate Nuclear Decommissioning in the Draft Report. One enhancement the parties requested was to provide this analysis over all four years, rather than 2011 and 2013 as originally studied. Accordingly, PG&E has supplemented its original analysis with additional data.

Specifically, for each year, PG&E has provided the following by customer class:

1) Forecast sales;
2) Forecast revenue based on total revenue requirement;
3) Actual sales;
4) Reallocated revenue based on actual sales and total revenue requirement; and
5) Revenue derived based on actual sales and adopted rate.

To make this comparison in both the Draft Report and for the current analysis, PG&E calculated the revenue for the year that would have been collected based on the actual sales and the rate that was in place on January 1 of each year which was derived based on a forecast of sales. PG&E uses this value as a proxy for the actual revenue. PG&E next calculated the revenue for each customer group using the actual sales as opposed to the forecast of sales used for the year.

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12 The following components are collected from agricultural customers in energy charges that do not vary by season or time of use: Transmission, Public Purpose Programs, Nuclear Decommissioning, the Energy Cost Recovery Amount, the New System Generation Charge (NSGC), the Department of Water Resources Bond Charge, and the Competition Transition Charge (CTC). Transmission charges are subject to Federal Energy Regulatory Commission jurisdiction. NSGC and CTC are not allocated based on marginal cost, but instead use load allocators called 12-month coincident peak (NSGC) and 100 peak hours (CTC). It would be a reasonable study enhancement to look at the 'perfect' allocation compared to the actual revenue from these two rate components.

In general, when a higher level of sales is assumed to collect the same amount of revenue, the average rate for the component is lower. Even though that higher level of sales may only be attributed to one customer class, the effect of perfectly forecast sales is to lower rates for all customer groups so that the correct revenue requirement is collected, assuming there is no change in cost. A comparison by class of forecast revenue based on the revenue requirement and forecast sales, forecast revenue requirement using actual sales (i.e., reallocated revenue) and revenue derived based on the actual sales and the adopted rate (which is a proxy for actual revenue) is provided in Attachment 7.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX F

ATTACHMENT 1

DISCOVERY

PACIFIC GAS AND ELECTRIC COMPANY
APPENDIX F
ATTACHMENT 1
DISCOVERY

First Data Request from the Agricultural Energy Consumers Association (AECA) and from the California Farm Bureau Federation, or the Agricultural Parties.

In response to Pacific Gas and Electric Company's (PG&E) request for data requirements, Agricultural Parties provided the following request. PG&E compiled the data response and provided it as AECA DR-007 on September 4, 2015.

The Agricultural Parties recommend using the last 10 years of data (2005-2014) in order to provide for a long enough period to include various types of water and economic conditions while keeping the data collection and analysis manageable. The data needed for the analysis are as follows:

1. Hydrologic traces (i.e., annual water flows) for the major river basins (e.g. Four Rivers Index published by California Department of Water Resources);
2. Rainfall totals, comparable with those used PG&E's load forecasting model;
3. Forecasted kilowatt-hour (kWh) sales (total and bundled) adopted for each customer class in each GRC proceeding over the relevant period;
4. Forecasted kilowatt-hour (kWh) sales (total and bundled) adopted for each customer class in each ERRA proceeding over the relevant period;
5. Forecasted electric rate revenues adopted for each customer class and for the system total in each GRC Phase II proceeding over the relevant period, with generation and non-generation revenue requirements separately shown;
6. Actual kWh sales for each customer class in each year;
7. Actual electric rate revenues for each customer class in each year; and
8. Total system electric revenue requirement adopted for each year (in the Annual Electric True-Up or its equivalent), with ERRA generation and non-ERRA generation revenue requirements separately shown.

Data Request from the California Large Energy Consumers Association (CLECA)

In response to PG&E's request for data requirements, the California Large Energy Consumers Association (CLECA) provided the following request. For the period beginning 2004, data provided to AECA also satisfies the CLECA requirement. Information by class was provided for the period 1995 through 2004. PG&E compiled the data response and provided it as CLECA DR-012 on September 11, 2015.

CLECA believes that the comparison should be made over a long period (20 years) to take into account variations due to business cycles as well as weather cycles. We note that PG&E's FERC Form 1, page 304, states the recorded sales and revenues by rate schedule. We propose that PG&E compile 20 years of Form 1 data by rate schedule and for the same period produce the annual ERRA, or previously, ECAC forecasts for each customer class. With this set of data, we'd be able to see what kind of year-to-year variation occurs for each schedule over a long period. We would also be able to compare the recorded data to the forecast data at least by customer class so as to indicate the degree of forecast error that might be occurring.

Second Data Request From Agricultural Parties

Subsequent to the workshop, on September 30, 2015, AECA requested the following information. PG&E compiled the data response and provided it as AECA DR-008 on October 29, 2015.

For the General Rate Cases since the 2003 filing, provide the following:

a. marginal costs used for revenue allocation in the settlements by component, i.e., generation, distribution, customer services, by rate class;

b. EPMC scalers applied by component by rate class (likely the same for each rate class);

c. Transmission costs by rate class, and whether any scaler adjustments were made before being added to revenue requirements and retail rates; and

d. Other cost components explicitly included in the revenue allocation by rate class, e.g., nuclear decommissioning, public purpose programs, etc.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX F

ATTACHMENT 2

DEFINITION OF TERMS

PACIFIC GAS AND ELECTRIC COMPANY
APPENDIX F
ATTACHMENT 2
DEFINITION OF TERMS

1. Average Rate – the average bundled total rate for a given class is the total revenue from bundled customers in that class divided by total bundled sales for that class. Similarly, the average generation rate is the generation revenue divided by bundled sales. The average rate for non-generation components, such as the average distribution rate, is total revenue for that component divided by total sales (including Direct Access/Community Choice Aggregation (DA/CCA)).
2. Actual (or Recorded or Billed) – actual/recorded/billed data refers to the amount of revenue, sales, load (Peak Cost Allocation Factors or Final Line Transformer demand) or billing determinants actually incurred for each year in question. Actual data may be total (including DA/CCA) or bundled (excluding DA/CCA).
3. Forecast – forecast data refers to the amount of revenue, sales or billing determinants forecasted for each year in question. Forecasted revenues (and rates) come from each year's Annual Electric True-Up while sales and billing determinant forecasts come from each year's Energy Resource Recovery Account proceeding. Forecast data may be total (including DA/CCA) or bundled (excluding DA/CCA), depending on purpose.
4. Perfect forecast – this report uses the term 'perfect' forecast to denote the forecast that would have been developed if the actual sales data for each class was known in advance and if standard methods were applied.
5. Revenue allocation – the process in which a total revenue requirement is divided between the classes. For General Rate Case allocations, distribution and generation revenue is typically allocated in proportion to marginal cost revenue.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX F

ATTACHMENT 3

PRESENTATIONS FROM WORKSHOP 1, SEPTEMBER 22, 2015

PG&E Agricultural Class Balancing Account Study

Presentation on behalf of the
Agricultural Energy Consumers Association

Presented by Richard McCann

M.CUBED

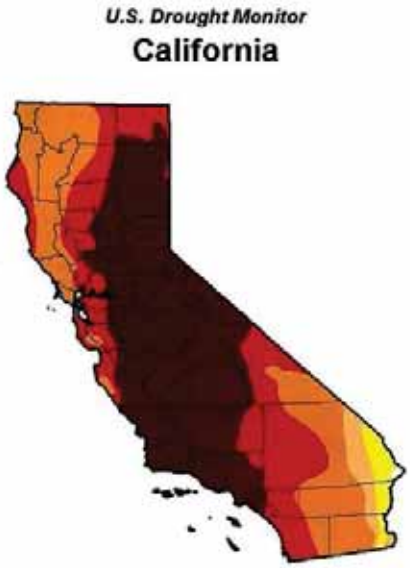
Statement of the Problem

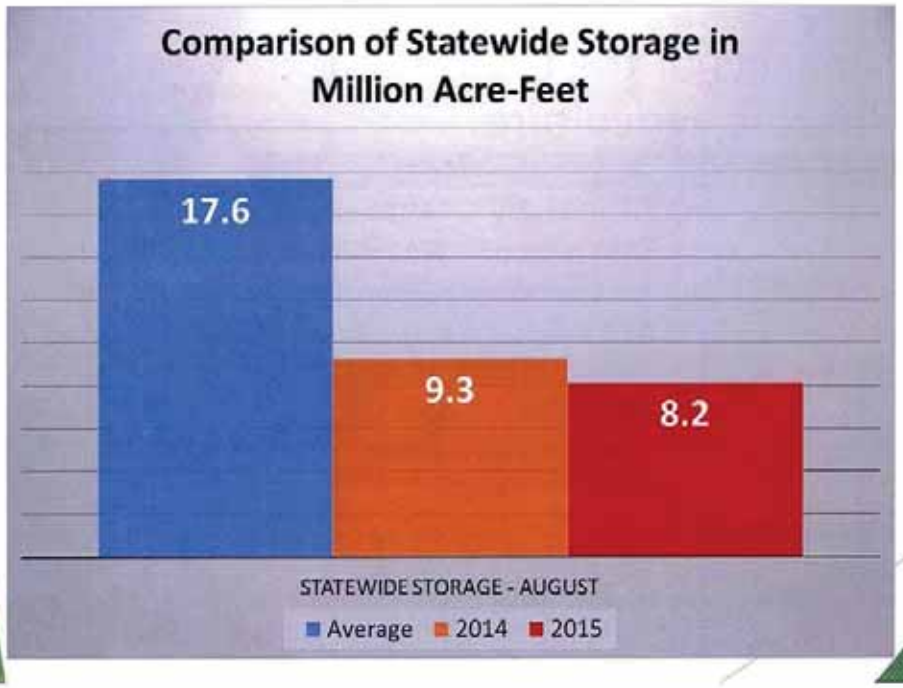
- Agriculture is uniquely affected by variations in external factors beyond growers' control—i.e., water availability.
  - Electricity load varies more than any class as a result—up to ***32%*** from forecasted
- A review of historic revenue collection shows that on average the agricultural rate group has paid PG&E more than the projected revenue requirements assigned in each GRC.
- California is now in a record drought, and this overcollection is accruing to a substantial amount.
- What are the solutions given that droughts and floods cannot be readily forecasted?

M.CUBED

California's Record Drought

- The smallest Sierra snowpack on record with water content estimated at just 5 percent of long-term averages.
  - Reported as the driest in at least 500 years.
- More than two-thirds of the state is in an "extreme" drought, with more than 40 percent in "exceptional" drought according to the U.S. Drought Monitor.





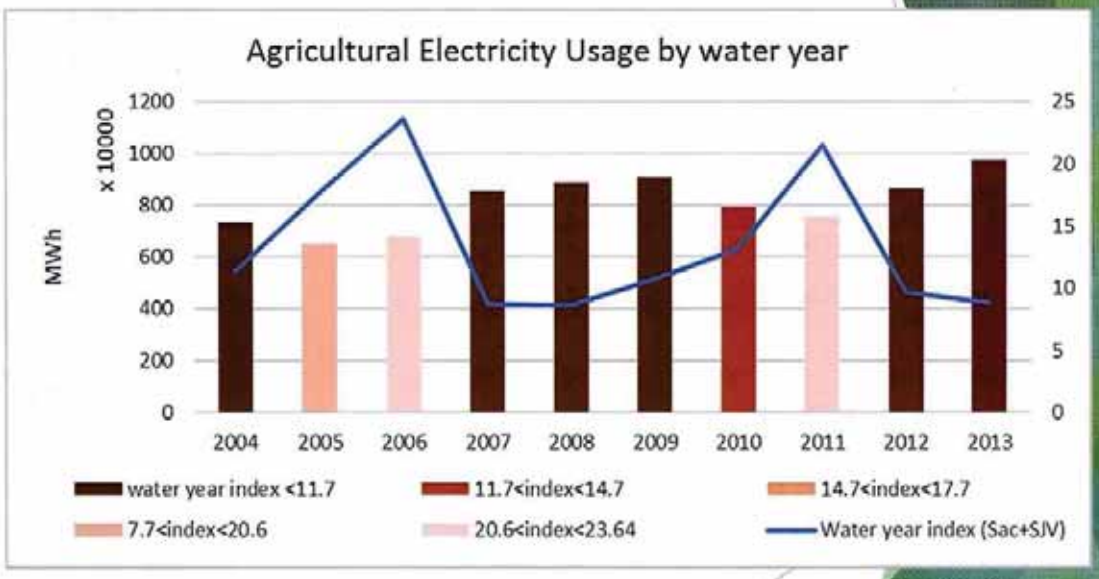
Economic impacts of the drought on California agriculture

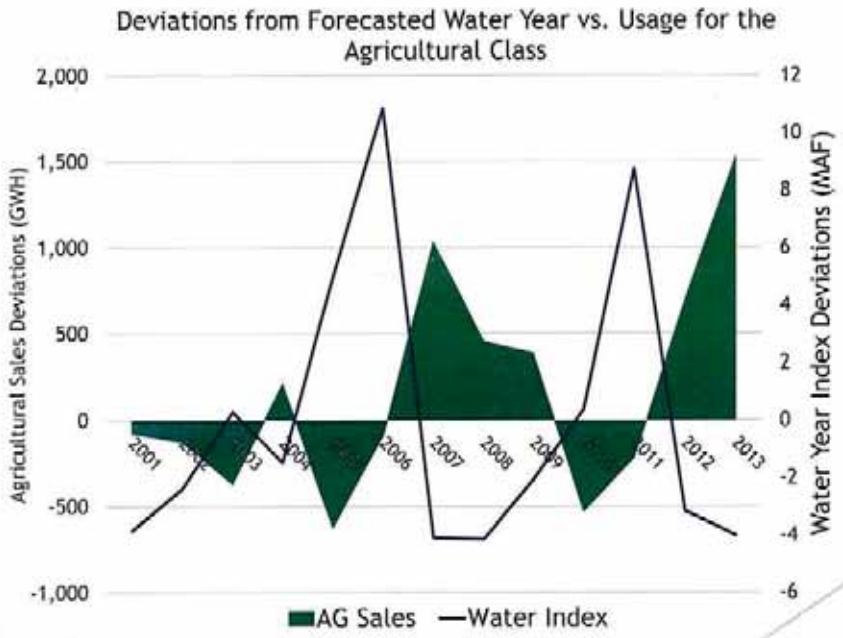
Statewide Costs	2014	2015
Crop revenue loss	$810 million	$850 million
Additional pumping cost	**$454 million**	**$600 million**
Livestock and dairy revenue loss	$203 million	$350 million
Total direct loss	$1.5 billion	$1.8 billion
total economic cost	$2.2 billion	$2.7 billion
total job losses	17,100	18,600
Size of statewide agricultural revenues (2012 $)	$48 billion	

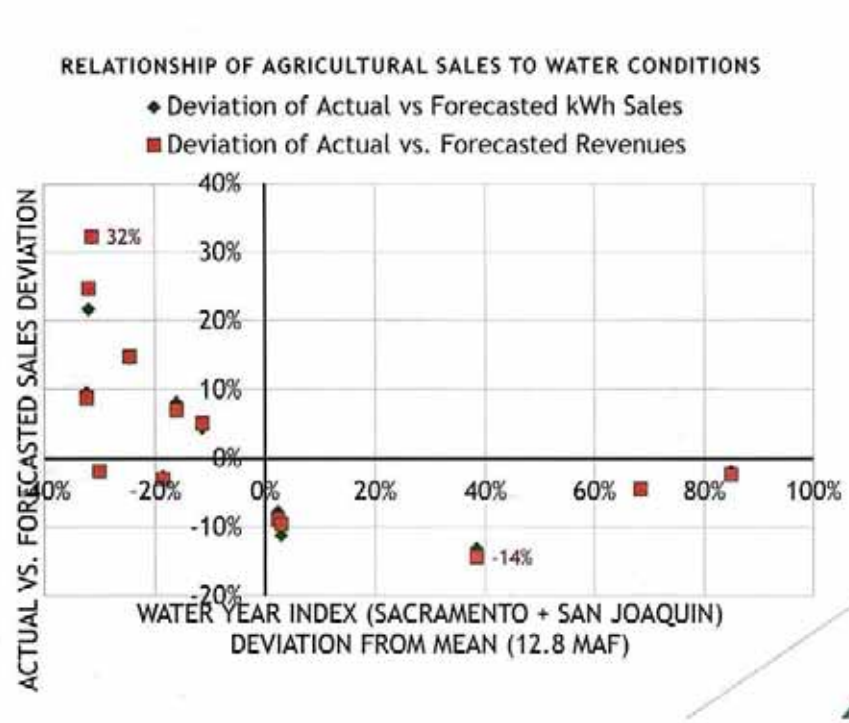
Howitt, R.E., Medellin-Azuara, J., MacEwan, D., Lund, J.R. and Sumner, D.A. (2014).

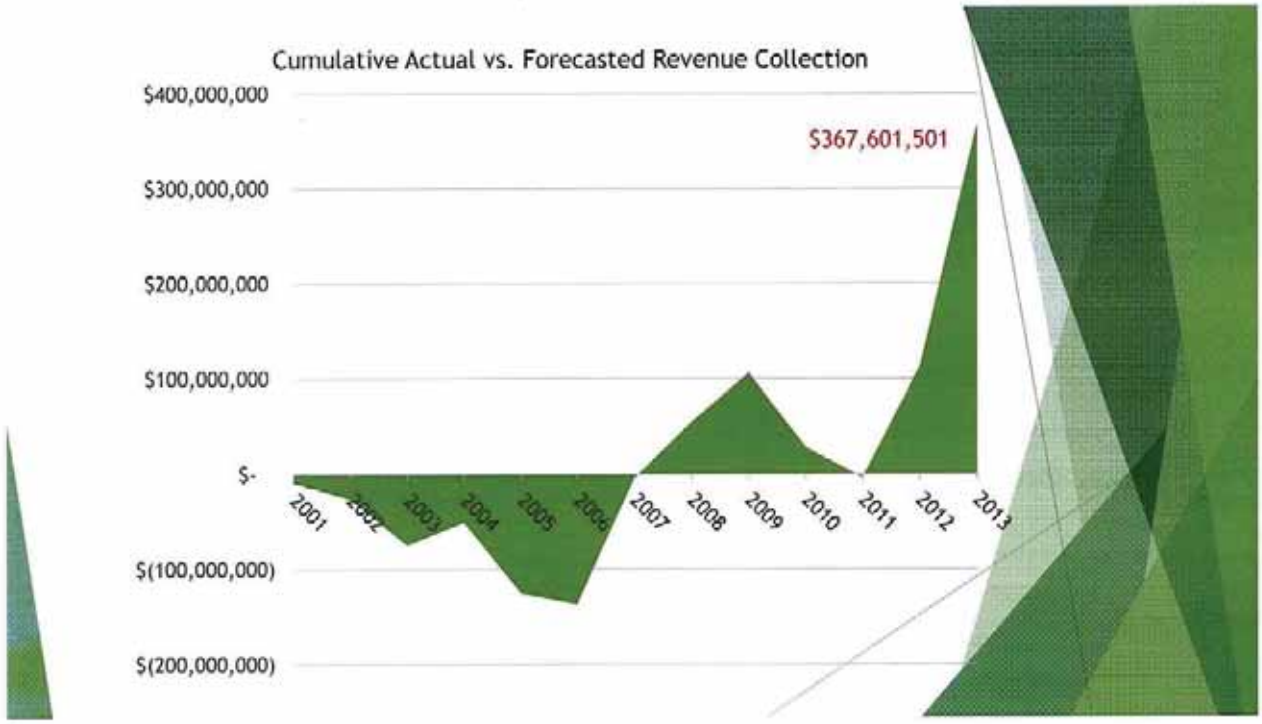
Agricultural Class Statistics

- Average annual kWh usage for 2001-13 = 4,750 GWH
- Average annual revenues for 2001-13 = $635 million
- Average water year index = 12.8 MAF




Deviations from Forecasted Water Year vs. Usage for the Agricultural Class
Agricultural Sales Deviations (GWH)
Water Year Index Deviations (MAF)
2,000
1,500
1,000
500
0
-500
-1,000
12
10
8
6
4
2
0
-2
-4
-6
2001
2003
2006
2007
2008
2011
2012
2013
AG Sales
Water Index


RELATIONSHIP OF AGRICULTURAL SALES TO WATER CONDITIONS
Deviation of Actual vs Forecasted kWh Sales
Deviation of Actual vs. Forecasted Revenues
ACTUAL VS. FORECASTED SALES DEVIATION
40%
30%
20%
10%
0%
-10%
-20%
-40%
-20%
0%
20%
40%
60%
80%
100%
32%
-14%
WATER YEAR INDEX (SACRAMENTO + SAN JOAQUIN)
DEVIATION FROM MEAN (12.8 MAF)



Possible Solutions

- Retrospective balancing account with other rate groups with cumulative accumulation deadbands.
- Rate surcharge to prepay reserve funds for agriculture and for other rate groups to repay.
- No obvious forecasting solution.
- Other ideas?

Data Required for Analysis

- Last 10 years of data (2005-2014) in order to provide for a long enough period to include various types of water and economic conditions while keeping the data collection and analysis manageable.
- The data needed for the analysis are as follows:
  - Hydrologic traces (i.e., annual water flows) for the major river basins (e.g. Four Rivers Index published by California Department of Water Resources);
  - Rainfall totals, comparable with those used PG&E's load forecasting model;
  - Forecasted kilowatt-hour (kWh) sales (total and bundled) adopted for each customer class in each GRC proceeding over the relevant period;
  - Forecasted kilowatt-hour (kWh) sales (total and bundled) adopted for each customer class in each ERRA proceeding over the relevant period;
  - Forecasted electric rate revenues adopted for each customer class and for the system total in each GRC Phase II proceeding over the relevant period, with generation and non-generation revenue requirements separately shown;
  - Actual kWh sales for each customer class in each year;
  - Actual electric rate revenues for each customer class in each year; and
  - Total system electric revenue requirement adopted for each year (in the Annual Electric True-Up or its equivalent), with ERRA generation and non-ERRA generation revenue requirements separately shown.

M.CUBED

Agricultural Class Balancing Account Study

PG&E

Workshop 1
September 22, 2015

Today's Agenda

Time	Topic/Action
10:00 am	Introductions
10:15 am	Study Objectives
10:30 am	Schedule
10:45 am	Data Requests and Sales Review
11:15 am	Studies
12:00 am	Next Steps

Overview of Study Objectives

Develop analysis to examine the desirability of a **balancing account** that addresses the **high level of sales variability** and **sales forecast uncertainty** pertaining to the **agricultural class**.

Such analyses would review:

- **year-to-year volatility of agricultural class revenues and sales** versus other customer class revenues and sales,

and include

- **an assessment of possible over-collection of agricultural class revenue that accounts for variation** in both PG&E's **cost of service** and **revenues collected** due to agricultural sales variability.

Study Schedule

	Planned	Completed	Comment
Data Inquiry		3/25/2015	1st quarter
Provide Data AG Parties	9/8/2015	9/4/2015	2 weeks prior to workshop
Provide Data CLECA	9/8/2015	9/11/2015	2 weeks prior to workshop
1st Workshop		9/22/2015	By 9/24/2015
Draft Report	By 10/30/2015		5 months prior to filing GRC Phase II
2nd Workshop	On or after 11/16/2015		No less than 2 weeks following the draft report
Comments Due	By 12/11/2015		6 weeks following draft report
Completion of Report	By 12/30/2015		3 months prior to filing GRC II
Report Filed	3/31/2016		With GRC II filing

Data Requests

- **AG Parties:**

- The Agricultural Parties recommend using the **last 10 years** of data (2005-2014) in order to provide for a long enough period to include various types of water and economic conditions while keeping the data collection and analysis manageable.
- Data needed for the analysis:
- **1) Hydrologic traces** (i.e., annual water flows) for the major river basins (e.g. Four Rivers Index published by California Department of Water Resources);
- **2) Rainfall totals**, comparable with those used PG&E's load forecasting model;
- **3) Forecasted kilowatt-hour (kWh) sales (total and bundled)** adopted for each customer class in each GRC proceeding over the relevant period;
- **4) Forecasted kilowatt-hour (kWh) sales (total and bundled)** adopted for each customer class in each ERRA proceeding over the relevant period;

Data Requests - Continued

AG Parties (continued)

5) Forecasted electric rate revenues adopted for each customer class and for the system total in each GRC Phase II proceeding over the relevant period, with generation and non-generation revenue requirements separately shown;

6) Actual kWh sales for each customer class in each year;

7) Actual electric rate revenues for each customer class in each year; and

8) Total system electric revenue requirement adopted for each year (in the Annual Electric True-Up or its equivalent), with ERRA generation and non-ERRA generation revenue requirements separately shown.

Data Requests – Continued

CLECA

CLECA believes that the comparison should be made **over a long period (20 years)** to take into account variations due to business cycles as well as weather cycles.

CLECA notes that PG&E's FERC Form 1, page 304, states the recorded sales and revenues by rate schedule.

CLECA proposes that PG&E compile 20 years of Form 1 data by rate schedule and for the same period produce the annual ERRA, or previously, ECAC forecasts for each customer class.

With this set of data, CLECA would like to be able to see what kind of year-to-year variation occurs for each schedule over a long period.

CLECA would also be able to compare the recorded data to the forecast data, at least by customer class, so as to indicate the degree of forecast error that might be occurring.

Sales Review

Year	Actual (GWh)				Forecast (GWh)				% Variance			
	Res	Coml	Ind	AG	Res	Coml	Ind	AG	Res	Coml	Ind	AG
1995	24,391	26,742	16,665	3,478	24,845	27,508	17,467	3,803	-1.8%	-2.8%	-4.6%	-8.5%
1996	25,458	27,595	15,647	3,631	24,946	27,704	17,367	3,548	2.1%	-0.4%	-9.9%	2.4%
1997	25,946	28,775	16,824	3,932	25,457	27,844	17,678	3,758	1.9%	3.3%	-4.8%	4.6%
1998	26,846	28,810	16,290	3,069	26,535	28,399	17,611	3,743	1.2%	1.4%	-7.5%	-18.0%
1999	27,739	30,391	16,676	3,739	26,850	28,867	17,380	3,549	3.3%	5.3%	-4.1%	5.4%
2000	28,753	31,729	16,804	3,818	27,197	29,367	17,568	3,530	5.7%	8.0%	-4.3%	8.2%
2001	26,920	30,931	16,724	4,150	28,848	31,805	17,223	3,423	-6.7%	-2.7%	-2.9%	21.2%
2002	27,353	30,720	13,327	3,930	26,445	29,833	15,704	3,360	3.4%	3.0%	-15.1%	17.0%
2003	29,025	31,888	14,653	3,909	27,405	30,981	15,874	3,798	5.9%	2.9%	-7.7%	2.9%
2004	29,452	32,267	14,796	4,301	28,511	31,759	15,190	3,995	3.3%	1.6%	-2.6%	7.7%
2005	29,752	32,375	14,931	3,742	29,159	32,456	15,280	4,005	2.0%	-0.2%	-2.3%	-6.6%
2006	31,013	33,492	15,165	3,838	30,054	33,616	15,249	3,915	3.2%	-0.4%	-0.5%	-2.0%
2007	30,797	33,984	15,158	5,403	31,026	33,156	15,072	4,652	-0.7%	2.5%	0.6%	16.1%
2008	31,454	34,053	16,148	5,594	31,558	33,642	15,479	4,285	-0.3%	1.2%	4.3%	30.6%
2009	31,235	32,958	14,806	5,803	31,927	34,975	15,834	4,430	-2.2%	-5.8%	-6.5%	31.0%
2010	30,744	32,862	14,415	5,071	30,856	33,648	15,458	5,081	-0.4%	-2.3%	-6.7%	-0.2%
2011	30,872	32,841	14,497	4,691	31,173	33,914	14,639	5,163	-1.0%	-3.2%	-1.0%	-9.1%
2012	31,082	32,680	15,353	6,179	32,092	33,028	15,045	5,239	-3.1%	-1.1%	2.0%	17.9%
2013	30,990	32,732	14,958	7,022	32,126	32,538	15,000	5,045	-3.5%	0.6%	-0.3%	39.2%
2014	29,835	32,431	15,648	7,611	31,807	33,658	14,550	5,807	-6.2%	-3.6%	7.6%	31.0%

Examine Rate Changes

Examine the methods used to implement rate changes for revenue requirement changes

- Compare recorded and forecast billing determinants.
- Determine the impact on revenue allocation and total rates for different billing determinant assumptions

Cost of Service

Develop an assessment of possible over-collection of agricultural class revenue that accounts for variation in both PG&E's cost of service and revenues collected due to agricultural sales variability.

Simulate revenue allocation if forecast assumptions were perfect in the context of GRC II.

- **Select low and high year**. For example, 2008, 2009, 2013 and 2014 were under-forecast. 2005 and 2011 were over-forecast.
- **Develop revenue allocation based on standard costing.**
- **Develop revenue allocation using perfect assumptions** (for example, PCAF in 2009 would be actual PCAF in 2009 rather than an average of 3 prior years).
- **Compare resulting cost of service and results**

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Thank You

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX F

ATTACHMENT 4

SALES AND AVERAGE RATE VARIABILITY

PACIFIC GAS AND ELECTRIC COMPANY
APPENDIX F
ATTACHMENT 4
SALES AND AVERAGE RATE VARIABILITY

TABLE 1
PG&E FORECAST VERSUS ACTUAL SALES
1995-2014

	Actual (MWh)				Forecast (MWh)				% Variance			
Year	Residential	Commercial	Industrial	Agricultural	Residential	Commercial	Industrial	Agricultural	Residential	Commercial	Industrial	Agricultural
1995	24,391,280	26,742,351	16,665,338	3,478,199	24,845,118	27,508,160	17,467,432	3,802,529	-1.8%	-2.8%	-4.6%	-8.5%
1996	25,457,707	27,594,793	15,646,645	3,631,376	24,945,988	27,704,021	17,366,722	3,547,899	2.1%	-0.4%	-9.9%	2.4%
1997	25,946,061	28,774,710	16,824,296	3,931,906	25,456,504	27,843,764	17,678,056	3,757,964	1.9%	3.3%	-4.8%	4.6%
1998	26,846,421	28,809,819	16,290,467	3,068,517	26,534,723	28,399,335	17,610,867	3,743,465	1.2%	1.4%	-7.5%	-18.0%
1999	27,739,169	30,390,763	16,675,970	3,739,442	26,850,000	28,866,876	17,379,973	3,548,800	3.3%	5.3%	-4.1%	5.4%
2000	28,753,363	31,729,382	16,804,099	3,818,471	27,197,000	29,367,173	17,568,251	3,529,600	5.7%	8.0%	-4.3%	8.2%
2001	26,919,816	30,931,499	16,724,388	4,149,637	28,847,627	31,804,732	17,223,393	3,422,874	-6.7%	-2.7%	-2.9%	21.2%
2002	27,352,506	30,720,415	13,327,035	3,930,434	26,445,320	29,832,977	15,703,947	3,359,508	3.4%	3.0%	-15.1%	17.0%
2003	29,024,571	31,888,262	14,652,572	3,908,761	27,404,692	30,981,227	15,874,291	3,797,826	5.9%	2.9%	-7.7%	2.9%
2004	29,451,812	32,267,463	14,795,824	4,300,632	28,510,914	31,758,572	15,189,790	3,994,756	3.3%	1.6%	-2.6%	7.7%
2005	29,752,492	32,375,350	14,931,163	3,742,178	29,158,534	32,455,548	15,279,718	4,005,422	2.0%	-0.2%	-2.3%	-6.6%
2006	31,013,224	33,492,219	15,165,406	3,838,454	30,054,360	33,615,827	15,249,018	3,915,100	3.2%	-0.4%	-0.5%	-2.0%
2007	30,797,140	33,984,106	15,158,490	5,402,882	31,026,230	33,156,218	15,072,109	4,652,438	-0.7%	2.5%	0.6%	16.1%
2008	31,454,145	34,053,289	16,147,954	5,594,023	31,558,385	33,641,785	15,478,901	4,284,896	-0.3%	1.2%	4.3%	30.6%
2009	31,234,681	32,958,064	14,805,543	5,803,346	31,926,840	34,974,822	15,834,106	4,429,911	-2.2%	-5.8%	-6.5%	31.0%
2010	30,744,336	32,862,310	14,414,954	5,070,535	30,856,068	33,648,340	15,458,127	5,081,483	-0.4%	-2.3%	-6.7%	-0.2%
2011	30,871,668	32,841,442	14,496,780	4,691,455	31,172,532	33,913,571	14,638,655	5,162,764	-1.0%	-3.2%	-1.0%	-9.1%
2012	31,082,050	32,679,971	15,352,774	6,178,539	32,091,672	33,028,374	15,045,456	5,238,918	-3.1%	-1.1%	2.0%	17.9%
2013	30,990,228	32,731,770	14,958,256	7,021,976	32,125,796	32,537,882	14,999,632	5,044,798	-3.5%	0.6%	-0.3%	39.2%
2014	29,835,314	32,431,217	15,648,127	7,610,559	31,806,532	33,657,833	14,549,585	5,807,472	-6.2%	-3.6%	7.6%	31.0%

Check	Recd Sales	Recd Sale ck	Total Forecast Sales	Total Forecast Sales Listed	Percent Listed of Total Forecast
1995	71,277,167	71,277,167	74,883,742	73,623,239	98.3%
1996	72,330,522	72,330,522	74,794,451	73,564,630	98.4%
1997	75,476,972	75,476,972	75,984,997	74,736,288	98.4%
1998	75,015,223	75,015,223	77,206,954	76,288,390	98.8%
1999	78,545,344	78,545,344	77,517,649	76,645,649	98.9%
2000	81,105,316	81,105,316	78,631,058	77,662,024	98.8%
2001	78,725,341	78,725,341	82,290,571	81,298,626	98.8%
2002	75,330,391	75,330,391	76,314,200	75,341,752	98.7%
2003	79,474,166	79,474,166	79,170,976	78,058,036	98.6%
2004	80,815,731	80,815,731	80,633,986	79,454,032	98.5%
2005	80,801,182	80,801,182	82,036,159	80,899,222	98.6%
2006	83,509,304	83,509,304	83,863,787	82,834,305	98.8%
2007	85,342,618	85,342,618	84,826,721	83,906,995	98.9%
2008	87,249,410	87,249,410	85,889,434	84,963,967	98.9%
2009	84,801,633	84,801,633	88,116,531	87,165,679	98.9%
2010	83,092,136	83,092,136	86,030,632	85,044,018	98.9%
2011	82,901,346	82,901,346	85,851,953	84,887,522	98.9%
2012	85,293,334	85,293,334	86,379,026	85,404,419	98.9%
2013	85,702,230	85,702,230	85,662,789	84,708,109	98.9%
2014	85,525,217	85,525,217	86,929,376	85,821,422	98.7%

Sales data not included in the table include revenue account 355 (streetlights), 356 (public authority), 357 (railway) and 360 (interdepartmental). The table includes residential sales (revenue account 350 and 351), commercial sales (revenue account 352 and 353), industrial sales (revenue account 359) and agricultural sales (revneue account 354). On a forecast basis, more than 98% of total sales are reflected in the table.

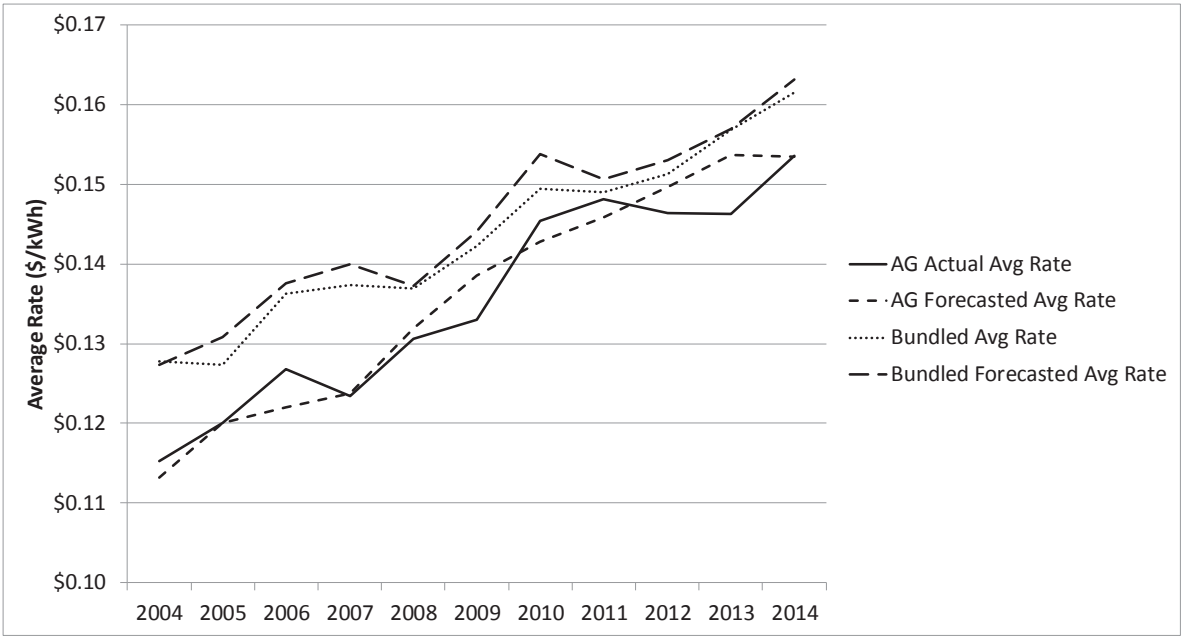
Forecast Sales Source

1995 A. 94-12-005 / Exhibit No. 6 / Table 4A-2 / Page 4A-9
1996 D.95-12-051
1997 D.96-12-080
1998 D.97-08-056
1999 A.97-12-020 / Exhibit No. 6 / Table 4A-1 (99 GRC Forecast)

PACIFIC GAS AND ELECTRIC COMPANY
APPENDIX F
ATTACHMENT 4
SALES AND AVERAGE RATE VARIABILITY
(Continued)

TABLE 2
PG&E FORECAST VERSUS ACTUAL AVERAGE AGRICULTURAL RATES
2004-2014

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
AG Actual Avg Rate	0.11522	0.12002	0.12682	0.12338	0.13058	0.13297	0.14545	0.14807	0.14634	0.14624	0.15363
AG Forecasted Avg Rate	0.11319	0.12006	0.12195	0.12374	0.13193	0.13850	0.14284	0.14581	0.14970	0.15364	0.15346
Bundled Avg Rate	0.12780	0.12737	0.13623	0.13735	0.13690	0.14228	0.14948	0.14904	0.15133	0.15689	0.16147
Bundled Forecasted Avg Rate	0.12729	0.13079	0.13761	0.13998	0.13721	0.14412	0.15383	0.15062	0.15304	0.15700	0.16313



PACIFIC GAS AND ELECTRIC COMPANY
APPENDIX F
ATTACHMENT 4
SALES AND AVERAGE RATE VARIABILITY
(Continued)

TABLE 3
PG&E FORECAST VERSUS ACTUAL AVERAGE RATES BY CLASS
2005-2014

	2005			2006			2007			2008		
	Recorded	Forecast	Variance	Recorded	Forecast	Variance	Recorded	Forecast	Variance	Recorded	Forecast	Variance
Residential	$0.12914	$0.12892	0.2%	$0.14511	$0.14320	1.3%	$0.14935	$0.15157	-1.5%	$0.15034	$0.14897	0.9%
Small L&P	$0.14580	$0.15133	-3.7%	$0.15389	$0.15218	1.1%	$0.15833	$0.15964	-0.8%	$0.16199	$0.16124	0.5%
Medium L&P	$0.13907	$0.14366	-3.2%	$0.14373	$0.14434	-0.4%	$0.14338	$0.14458	-0.8%	$0.13954	$0.13845	0.8%
E19	$0.11708	$0.12944	-9.5%	$0.12166	$0.13153	-7.5%	$0.12106	$0.12888	-6.1%	$0.11861	$0.12047	-1.5%
Streetlights	$0.14930	$0.15219	-1.9%	$0.15996	$0.15865	0.8%	$0.16817	$0.17228	-2.4%	$0.15869	$0.15589	1.8%
Standby	$0.13020	$0.13700	-5.0%	$0.12527	$0.12622	-0.8%	$0.12460	$0.11461	8.7%	$0.11762	$0.12006	-2.0%
AG A	$0.18061	$0.20705	-12.8%	$0.19822	$0.21583	-8.2%	$0.19425	$0.23570	-17.6%	$0.20280	$0.21936	-7.5%
AG B/C	$0.11132	$0.11029	0.9%	$0.11678	$0.11140	4.8%	$0.11465	$0.11309	1.4%	$0.12204	$0.12278	-0.6%
AG Total	$0.12002	$0.12006	0.0%	$0.12682	$0.12195	4.0%	$0.12338	$0.12374	-0.3%	$0.13058	$0.13193	-1.0%
E20	$0.10220	$0.10741	-4.9%	$0.10293	$0.10880	-5.4%	$0.10046	$0.10208	-1.6%	$0.10027	$0.09954	0.7%
Total	$0.12737	$0.13079	-2.6%	$0.13623	$0.13761	-1.0%	$0.13735	$0.13998	-1.9%	$0.13690	$0.13721	-0.2%

	2009			2010			2011			2012		
	Recorded	Forecast	Variance	Recorded	Forecast	Variance	Recorded	Forecast	Variance	Recorded	Forecast	Variance
Residential	$0.15244	$0.15813	-3.6%	$0.15608	$0.16549	-5.7%	$0.15482	$0.15658	-1.1%	$0.15977	$0.16109	-0.8%
Small L&P	$0.16869	$0.16779	0.5%	$0.17970	$0.18118	-0.8%	$0.17855	$0.17831	0.1%	$0.18410	$0.18397	0.1%
Medium L&P	$0.14876	$0.14587	2.0%	$0.16210	$0.16055	1.0%	$0.15984	$0.15818	1.0%	$0.16056	$0.15904	1.0%
E19	$0.12656	$0.12546	0.9%	$0.13322	$0.13959	-4.6%	$0.13179	$0.13700	-3.8%	$0.13401	$0.13832	-3.1%
Streetlights	$0.15622	$0.16126	-3.1%	$0.16232	$0.16473	-1.5%	$0.16206	$0.16269	-0.4%	$0.16461	$0.16859	-2.4%
Standby	$0.13567	$0.12730	6.6%	$0.12786	$0.12279	4.1%	$0.12680	$0.12020	5.5%	$0.12969	$0.11881	9.2%
AG A	$0.21003	$0.23001	-8.7%	$0.23289	$0.23435	-0.6%	$0.23443	$0.24631	-4.8%	$0.23420	$0.26109	-10.3%
AG B/C	$0.12477	$0.12921	-3.4%	$0.13624	$0.13325	2.2%	$0.13856	$0.13634	1.6%	$0.13730	$0.14039	-2.2%
AG Total	$0.13297	$0.13850	-4.0%	$0.14545	$0.14284	1.8%	$0.14807	$0.14581	1.6%	$0.14634	$0.14970	-2.2%
E20	$0.10929	$0.10391	5.2%	$0.11633	$0.11518	1.0%	$0.11656	$0.11496	1.4%	$0.11315	$0.11414	-0.9%
Total	$0.14228	$0.14412	-1.3%	$0.14948	$0.15383	-2.8%	$0.14904	$0.15062	-1.0%	$0.15133	$0.15304	-1.1%

	2013			2014		
	Recorded	Forecast	Variance	Recorded	Forecast	Variance
Residential	$0.16527	$0.16529	0.0%	$0.16180	$0.17455	-7.3%
Small L&P	$0.19035	$0.18892	0.8%	$0.19992	$0.19406	3.0%
Medium L&P	$0.16672	$0.16625	0.3%	$0.17985	$0.17423	3.2%
E19	$0.14106	$0.14364	-1.8%	$0.15325	$0.14954	2.5%
Streetlights	$0.16732	$0.17483	-4.3%	$0.18487	$0.18100	2.1%
Standby	$0.13954	$0.11863	17.6%	$0.14715	$0.12830	14.7%
AG A	$0.22157	$0.24761	-10.5%	$0.23525	$0.24116	-2.4%
AG B/C	$0.13857	$0.14425	-3.9%	$0.14607	$0.14481	0.9%
AG Total	$0.14624	$0.15364	-4.8%	$0.15363	$0.15346	0.1%
E20	$0.11847	$0.11883	-0.3%	$0.12789	$0.12148	5.3%
Total	$0.15689	$0.15700	-0.1%	$0.16147	$0.16313	-1.0%

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX F

ATTACHMENT 5

GENERATION COST OF SERVICE

Pacific Gas & Electric Company

TABLE 1 - Attachment 5

2017 GRC - Phase II

Balancing Account Study (using 2014 GENERATION Marginal Costs for all 4 years)

		Generation Cost of Service														
Year	Customer Class	Actual Bundled Sales	Average Capacity MC	Average Energy MC	Total Average MC	Total MC Revenue	MC Revenue Share	PCAF	System PCAF Share	kWh/kW	Actual Billed Revenue	Actual Billed Rate	Allocated Billed Revenue	Allocated Billed Rate	Revenue Difference (Bill - Allocated)	Average Rate Difference
		(GWh)	($/kWh)	($/kWh)	($/kWh)	($M)	(%)	(MW)	(%)	(hrs)	($M)	($/kWh)	($M)	($/kWh)	($M)	(%)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
	Calculation:	Recorded	= MC x Rec (9)	= MC x Rec (3)	= (4) + (5)	= (3) x (6)	= (7) / Total	Recorded	= (9) / Total	= (3) / (9)	Recorded	= (12) / (3)	= (8) x (12)	= (14 / (3)	= (12) - (14)	={ (13) - (15) } / (15)
2011	Residential	30,729	0.01654	0.04615	0.06269	1,926	41.40%	7,096	42.05%	4,330	2,340	0.07616	2,419	0.07873	-79	-3.27%
	Small L&P (incl. Streetlgts)	9,072	0.01411	0.04697	0.06108	554	11.91%	1,787	10.59%	5,077	608	0.06701	696	0.07671	-88	-12.64%
	Medium L&P	8,709	0.01708	0.04729	0.06437	561	12.05%	2,077	12.31%	4,193	949	0.10892	704	0.08085	244	34.72%
	Agriculture	**4,654**	**0.01854**	**0.04520**	**0.06373**	**297**	**6.37%**	**1,259**	**7.46%**	**3,696**	**334**	**0.07173**	**372**	**0.08005**	**-39**	**-10.38%**
	E-19	11,767	0.01513	0.04626	0.06139	722	15.53%	2,494	14.78%	4,719	837	0.07112	907	0.07710	-70	-7.75%
	E-20 (incl. Stdby)	10,152	0.01439	0.04398	0.05837	593	12.74%	2,162	12.81%	4,694	776	0.07642	744	0.07331	32	4.25%
	Total	75,082	0.01592	0.04605	0.06197	4,653	100.00%	16,875	100.00%	4,449	5,843	0.07783	5,843	0.07783	0	0.00%
2012	Residential	30,776	0.01601	0.04614	0.06215	1,913	40.87%	6,879	41.83%	4,474	2,093	0.06801	2,266	0.07363	-173	-7.64%
	Small L&P (incl. Streetlgts)	9,114	0.01272	0.04687	0.05959	543	11.60%	1,618	9.84%	5,633	585	0.06417	643	0.07060	-59	-9.10%
	Medium L&P	8,464	0.01619	0.04727	0.06346	537	11.48%	1,914	11.64%	4,422	778	0.09186	636	0.07519	141	22.18%
	Agriculture	**6,140**	**0.01711**	**0.04517**	**0.06228**	**382**	**8.17%**	**1,532**	**9.32%**	**4,007**	**425**	**0.06922**	**453**	**0.07379**	**-28**	**-6.18%**
	E-19	11,282	0.01500	0.04619	0.06119	690	14.75%	2,372	14.42%	4,757	923	0.08182	818	0.07250	105	12.86%
	E-20 (incl. Stdby)	10,739	0.01338	0.04384	0.05723	615	13.13%	2,131	12.96%	5,040	742	0.06906	728	0.06781	13	1.85%
	Total	76,516	0.01521	0.04596	0.06117	4,680	100.00%	16,446	100.00%	4,653	5,545	0.07247	5,545	0.07247	0	0.00%
2013	Residential	30,431	0.01957	0.04618	0.06575	2,001	42.08%	8,313	47.12%	3,661	2,541	0.08349	2,607	0.08567	-66	-2.54%
	Small L&P (incl. Streetlgts)	8,812	0.01273	0.04734	0.06007	529	11.13%	1,566	8.88%	5,626	599	0.06798	690	0.07826	-91	-13.14%
	Medium L&P	8,619	0.01576	0.04745	0.06321	545	11.46%	1,903	10.78%	4,530	836	0.09699	710	0.08236	126	17.77%
	Agriculture	**6,984**	**0.01434**	**0.04508**	**0.05942**	**415**	**8.73%**	**1,453**	**8.23%**	**4,808**	**502**	**0.07189**	**541**	**0.07742**	**-39**	**-7.14%**
	E-19	11,179	0.01442	0.04637	0.06079	680	14.29%	2,259	12.80%	4,950	957	0.08560	885	0.07920	72	8.08%
	E-20 (incl. Stdby)	9,980	0.01455	0.04405	0.05860	585	12.30%	2,148	12.18%	4,646	760	0.07611	762	0.07635	-2	-0.30%
	Total	76,005	0.01645	0.04611	0.06255	4,754	100.00%	17,641	100.00%	4,308	6,194	0.08150	6,194	0.08150	0	0.00%
2014	Residential	29,209	0.01759	0.04617	0.06377	1,863	40.34%	7,174	43.13%	4,071	2,682	0.09183	2,719	0.09308	-37	-1.34%
	Small L&P (incl. Streetlgts)	8,466	0.01347	0.04595	0.05942	503	10.90%	1,592	9.57%	5,317	631	0.07459	734	0.08674	-103	-14.01%
	Medium L&P	8,330	0.01590	0.04720	0.06309	526	11.38%	1,854	11.15%	4,493	751	0.09017	767	0.09210	-16	-2.10%
	Agriculture	**7,582**	**0.01422**	**0.04584**	**0.06006**	**455**	**9.86%**	**1,505**	**9.05%**	**5,037**	**601**	**0.07925**	**665**	**0.08768**	**-64**	**-9.61%**
	E-19	10,934	0.01465	0.04616	0.06081	665	14.40%	2,246	13.50%	4,869	1,242	0.11363	971	0.08877	272	28.01%
	E-20 (incl. Stdby)	10,330	0.01480	0.04383	0.05863	606	13.12%	2,261	13.59%	4,570	832	0.08051	884	0.08559	-52	-5.93%
	Total	74,850	0.01578	0.04590	0.06168	4,617	100.00%	16,632	100.00%	4,500	6,740	0.09004	6,740	0.09004	0	0.00%

Pacific Gas & Electric Company

TABLE 2 - Attachment 5

2017 GRC - Phase II

Balancing Account Study (using 2011 GENERATION Marginal Costs for all 4 years)

		Generation Cost of Service														
Year	Customer Class	Class Actual Bundled Sales	Average Capacity MC	Average Energy MC	Total Average MC	Total MC Revenue	MC Revenue Share	PCAF	System PCAF Share	kWh/kW	Actual Billed Revenue	Actual Billed Rate	Allocated Billed Revenue	Allocated Billed Rate	Revenue Difference (Bill - Allocated)	Average Rate Difference
		(GWh)	($/kWh)	($/kWh)	($/kWh)	($M)	(%)	(MW)	(%)	(hrs)	($M)	($/kWh)	($M)	($/kWh)	($M)	(%)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
	Calculation:	Recorded	= MC x Rec (9)	= MC x Rec (3)	= (4) + (5)	= (3) x (6)	= (7) / Total	Recorded	= (9) / Total	= (3) / (9)	Recorded	= (12) / (3)	= (8) x (12)	= (14) / (3)	= (12) - (14)	={ (13) - (15) } / (15)
2011	Residential	30,729	0.02638	0.04216	0.06854	2,106	41.49%	7,096	42.05%	4,330	2,340	0.07616	2,424	0.07889	-84	-3.46%
	Small L&P (incl. Streetlgts)	9,072	0.02250	0.04297	0.06547	594	11.70%	1,787	10.59%	5,077	608	0.06701	684	0.07536	-76	-11.08%
	Medium L&P	8,709	0.02724	0.04330	0.07054	614	12.10%	2,077	12.31%	4,193	949	0.10892	707	0.08120	241	34.14%
	Agriculture	**4,654**	**0.02981**	**0.04159**	**0.07139**	**332**	**6.54%**	**1,259**	**7.46%**	**3,696**	**334**	**0.07173**	**382**	**0.08218**	**-49**	**-12.71%**
	E-19	11,767	0.02414	0.04235	0.06649	782	15.41%	2,494	14.78%	4,719	837	0.07112	901	0.07654	-64	-7.08%
	E-20 (incl. Stdby)	10,152	0.02313	0.04064	0.06377	647	12.75%	2,162	12.81%	4,694	776	0.07642	745	0.07341	31	4.11%
	Total	75,082	0.02543	0.04218	0.06761	5,076	100.00%	16,875	100.00%	4,449	5,843	0.07783	5,843	0.07783	0	0.00%
2012	Residential	30,776	0.02554	0.04214	0.06767	2,083	40.99%	6,879	41.83%	4,474	2,093	0.06801	2,273	0.07386	-180	-7.93%
	Small L&P (incl. Streetlgts)	9,114	0.02028	0.04287	0.06315	576	11.33%	1,618	9.84%	5,633	585	0.06417	628	0.06893	-43	-6.90%
	Medium L&P	8,464	0.02582	0.04327	0.06910	585	11.51%	1,914	11.64%	4,422	778	0.09186	638	0.07541	139	21.81%
	Agriculture	**6,140**	**0.02751**	**0.04156**	**0.06908**	**424**	**8.35%**	**1,532**	**9.32%**	**4,007**	**425**	**0.06922**	**463**	**0.07539**	**-38**	**-8.18%**
	E-19	11,282	0.02394	0.04227	0.06621	747	14.70%	2,372	14.42%	4,757	923	0.08182	815	0.07227	108	13.22%
	E-20 (incl. Stdby)	10,739	0.02151	0.04052	0.06204	666	13.11%	2,131	12.96%	5,040	742	0.06906	727	0.06771	14	1.99%
	Total	76,516	0.02430	0.04210	0.06640	5,081	100.00%	16,446	100.00%	4,653	5,545	0.07247	5,545	0.07247	0	0.00%
2013	Residential	30,431	0.03121	0.04222	0.07343	2,235	42.89%	8,313	47.12%	3,661	2,541	0.08349	2,657	0.08731	-116	-4.37%
	Small L&P (incl. Streetlgts)	8,812	0.02031	0.04334	0.06364	561	10.76%	1,566	8.88%	5,626	599	0.06798	667	0.07567	-68	-10.16%
	Medium L&P	8,619	0.02515	0.04348	0.06863	592	11.35%	1,903	10.78%	4,530	836	0.09699	703	0.08160	133	18.86%
	Agriculture	**6,984**	**0.02303**	**0.04155**	**0.06458**	**451**	**8.66%**	**1,453**	**8.23%**	**4,808**	**502**	**0.07189**	**536**	**0.07678**	**-34**	**-6.36%**
	E-19	11,179	0.02301	0.04248	0.06549	732	14.05%	2,259	12.80%	4,950	957	0.08560	870	0.07786	87	9.94%
	E-20 (incl. Stdby)	9,980	0.02338	0.04074	0.06412	640	12.28%	2,148	12.18%	4,646	760	0.07611	761	0.07624	-1	-0.17%
	Total	76,005	0.02627	0.04228	0.06855	5,210	100.00%	17,641	100.00%	4,308	6,194	0.08150	6,194	0.08150	0	0.00%
2014	Residential	29,209	0.02806	0.04218	0.07024	2,052	40.77%	7,174	43.13%	4,071	2,682	0.09183	2,748	0.09407	-65	-2.38%
	Small L&P (incl. Streetlgts)	8,466	0.02149	0.04200	0.06348	537	10.68%	1,592	9.57%	5,317	631	0.07459	720	0.08502	-88	-12.27%
	Medium L&P	8,330	0.02537	0.04319	0.06856	571	11.35%	1,854	11.15%	4,493	751	0.09017	765	0.09182	-14	-1.79%
	Agriculture	**7,582**	**0.02268**	**0.04203**	**0.06471**	**491**	**9.75%**	**1,505**	**9.05%**	**5,037**	**601**	**0.07925**	**657**	**0.08666**	**-56**	**-8.55%**
	E-19	10,934	0.02339	0.04224	0.06563	718	14.26%	2,246	13.50%	4,869	1,242	0.11363	961	0.08789	281	29.29%
	E-20 (incl. Stdby)	10,330	0.02378	0.04053	0.06431	664	13.20%	2,261	13.59%	4,570	832	0.08051	890	0.08612	-58	-6.52%
	Total	74,850	0.02520	0.04204	0.06724	5,033	100.00%	16,632	100.00%	4,500	6,740	0.09004	6,740	0.09004	0	0.00%

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX F

ATTACHMENT 6

DISTRIBUTION COST OF SERVICE

Pacific Gas & Electric Company
2017 GRC - Phase II
Balancing Account Study (using 2014 DISTRIBUTION Marginal Costs)

TABLE 1 - Attachment 6

		Distribution Cost of Service																
Year	Customer Class	Recorded Actual Bundled & DA/CCA Sales	Average Primary MC	Average Secondary & New Business Primary MC	Average Customer MC	Total Average MC	Total MC Revenue	MC Revenue Share	PCAF	System PCAF Share	FLT	Customer-months	Actual Billed Revenue	Actual Billed Rate	Allocated Billed Revenue	Allocated Billed Rate	Revenue Difference (Bill - Allocated)	Average Rate Difference
		(GWh)	($/kWh)	($/kWh)	($/kWh)	($/kWh)	($M)	(%)	(MW)	(%)	(MW)	(#)	($M)	($/kWh)	($M)	($/kWh)	($M)	(%)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
	Calculation:	Recorded	= MCRev / (3)	= MCRev / (3)	= MCRev / (3)	=(4)+(5)+(6)	= (7) x (3)	= (8) / (Total)	Recorded	= (10) / (Total)	Recorded	Recorded	Recorded	= (14) / (3)	= (9) x (Total 14)	= (16) / (3)	= (14) - (16)	={(15)-(17)}/(17)
2011	Residential	30,872	0.01096	0.00668	0.01100	0.02864	884	49.46%	8,473	46.49%	14,131	55,252,818	1,945	0.06302	1,767	0.05723	179	10.11%
	Small L&P (incl. Streetlgts)	9,160	0.00898	0.00578	0.01653	0.03129	287	16.03%	1,819	9.98%	3,187	6,051,104	439	0.04788	573	0.06253	-134	-23.44%
	Medium L&P	9,486	0.00951	0.00550	0.00335	0.01836	174	9.74%	2,193	12.03%	3,697	593,745	431	0.04548	348	0.03668	83	23.98%
	Agriculture	**4,691**	**0.00925**	**0.00768**	**0.01335**	**0.03027**	**142**	**7.95%**	**1,530**	**8.39%**	**3,970**	**1,009,599**	**212**	**0.04521**	**284**	**0.06050**	**-72**	**-25.28%**
	E-19	14,726	0.00825	0.00382	0.00089	0.01297	191	10.68%	2,723	14.94%	3,686	211,280	354	0.02402	382	0.02591	-28	-7.31%
	E-20 (incl. Stdby)	14,641	0.00484	0.00208	0.00057	0.00749	110	6.13%	1,488	8.16%	2,161	14,466	191	0.01304	219	0.01497	-28	-12.85%
	Total	83,576	0.00893	0.00519	0.00726	0.02139	1,788	100.00%	18,226	100.00%	30,832	63,133,012	3,572	0.04274	3,572	0.04274	0	0.00%
2012	Residential	31,082	0.01130	0.00721	0.01098	0.02949	917	50.26%	7,198	45.71%	13,201	55,561,443	2,136	0.06872	2,016	0.06488	120	5.93%
	Small L&P (incl. Streetlgts)	9,267	0.00881	0.00593	0.01641	0.03114	289	15.82%	1,590	10.10%	2,922	6,073,891	486	0.05244	635	0.06851	-149	-23.46%
	Medium L&P	9,312	0.00921	0.00615	0.00342	0.01879	175	9.59%	1,897	12.05%	3,603	596,298	429	0.04608	385	0.04133	44	11.48%
	Agriculture	**6,179**	**0.00730**	**0.00669**	**0.01031**	**0.02431**	**150**	**8.24%**	**1,576**	**10.01%**	**3,718**	**1,027,533**	**281**	**0.04556**	**330**	**0.05349**	**-49**	**-14.82%**
	E-19	14,618	0.00772	0.00417	0.00090	0.01279	187	10.25%	2,281	14.49%	3,565	212,188	465	0.03178	411	0.02813	53	12.96%
	E-20 (incl. Stdby)	15,604	0.00431	0.00198	0.00054	0.00683	107	5.84%	1,204	7.65%	1,766	15,403	215	0.01380	234	0.01503	-19	-8.15%
	Total	86,062	0.00864	0.00546	0.00709	0.02119	1,824	100.00%	15,747	100.00%	28,775	63,486,756	4,012	0.04662	4,012	0.04662	0	0.00%
2013	Residential	30,990	0.01201	0.00676	0.01107	0.02983	924	40.68%	9,332	33.37%	13,914	55,827,699	2,144	0.06919	1,642	0.05297	503	30.62%
	Small L&P (incl. Streetlgts)	9,078	0.00793	0.00685	0.01676	0.03153	286	12.60%	1,720	6.15%	4,223	6,081,643	476	0.05242	508	0.05599	-32	-6.38%
	Medium L&P	9,499	0.00872	0.00598	0.01002	0.02472	235	10.33%	1,937	6.93%	3,987	596,588	421	0.04436	417	0.04389	5	1.09%
	Agriculture	**7,022**	**0.00823**	**0.00678**	**0.00907**	**0.02408**	**169**	**7.44%**	**1,616**	**5.78%**	**4,012**	**1,026,492**	**300**	**0.04270**	**300**	**0.04276**	**0**	**-0.13%**
	E-19	14,645	0.03545	0.00357	0.00222	0.04123	604	26.57%	12,800	45.77%	3,592	212,292	475	0.03244	1,072	0.07321	-597	-55.68%
	E-20 (incl. Stdby)	15,194	0.00109	0.00192	0.00055	0.00356	54	2.38%	560	2.00%	4,480	15,306	219	0.01440	96	0.00632	123	127.66%
	Total	86,428	0.01296	0.00529	0.00804	0.02629	2,273	100.00%	27,966	100.00%	34,207	63,760,020	4,035	0.04669	4,035	0.04669	0	0.00%
2014	Residential	29,835	0.01160	0.00714	0.01173	0.03047	909	49.01%	8,682	46.43%	14,111	56,151,146	1,534	0.05143	1,665	0.05581	-131	-7.85%
	Small L&P (incl. Streetlgts)	8,927	0.00894	0.00740	0.01722	0.03356	300	16.15%	1,905	10.19%	4,453	6,091,432	446	0.04993	549	0.06148	-103	-18.79%
	Medium L&P	9,388	0.01011	0.00588	0.00288	0.01887	177	9.55%	2,175	11.63%	3,597	500,851	354	0.03766	324	0.03456	29	8.98%
	Agriculture	**7,611**	**0.00961**	**0.00762**	**0.00902**	**0.02626**	**200**	**10.77%**	**1,760**	**9.41%**	**4,084**	**1,041,669**	**306**	**0.04020**	**366**	**0.04810**	**-60**	**-16.42%**
	E-19	14,585	0.00756	0.00355	0.00160	0.01272	185	10.00%	2,570	13.75%	3,591	321,016	539	0.03699	340	0.02329	200	58.81%
	E-20 (incl. Stdby)	15,897	0.00291	0.00182	0.00054	0.00528	84	4.52%	1,606	8.59%	4,444	15,459	219	0.01376	154	0.00966	65	42.39%
	Total	86,243	0.00870	0.00548	0.00732	0.02151	1,855	100.00%	18,698	100.00%	34,279	64,121,574	3,398	0.03940	3,398	0.03940	0	0.00%

Pacific Gas & Electric Company
2017 GRC - Phase II
Balancing Account Study (using DISTRIBUTION 2011 Marginal Costs)

TABLE 2 - Attachment 6

		Distribution Cost of Service																	
Year	Customer Class	Recorded Actual Bundled & DA/CCA Sales	Average Primary MC	Average Secondary & New Business Primary MC	Average Customer MC	Total Average MC	Total MC Revenue	MC Revenue Share	PCAF	System PCAF Share	FLT	Customer-months	Actual Billed Revenue	Actual Billed Rate	Allocated Billed Revenue	Allocated Billed Rate	Revenue Difference (Bill - Allocated)	Average Rate Difference
		(GWh)	($/kWh)	($/kWh)	($/kWh)	($/kWh)	($M)	(%)	(MW)	(%)	(MW)	(#)	($M)	($/kWh)	($M)	($/kWh)	($M)	(%)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
	Calculation:	Recorded	= MCRev / (3)	= MCRev / (3)	= MCRev / (3)	=(4)+(5)+(6)	= (7) x (3)	= (8) / (Total)	Recorded	= (10) / (Total)	Recorded	Recorded	Recorded	= (14) / (3)	= (9) x (Total 14)	= (16) / (3)	= (14) - (16)	={(15)-(17)}/(17)
2011	Residential	30,872	0.01560	0.00534	0.01368	0.03462	1,069	50.76%	8,473	46.49%	14,131	55,252,818	1,945	0.06302	1,813	0.05873	132	7.29%
	Small L&P (incl. Streetlgts)	9,160	0.01189	0.00472	0.02048	0.03709	340	16.13%	1,819	9.98%	3,187	6,051,104	439	0.04788	576	0.06292	-138	-23.91%
	Medium L&P	9,486	0.01188	0.00433	0.00503	0.02125	202	9.57%	2,193	12.03%	3,697	593,745	431	0.04548	342	0.03605	90	26.18%
	Agriculture	**4,691**	**0.01271**	**0.00631**	**0.01118**	**0.03020**	**142**	**6.73%**	**1,530**	**8.39%**	**3,970**	**1,009,599**	**212**	**0.04521**	**240**	**0.05123**	**-28**	**-11.76%**
	E-19	14,726	0.01023	0.00299	0.00238	0.01560	230	10.91%	2,723	14.94%	3,686	211,280	354	0.02402	390	0.02646	-36	-9.22%
	E-20 (incl. Stdby)	14,641	0.00554	0.00171	0.00123	0.00848	124	5.90%	1,488	8.16%	2,161	14,466	191	0.01304	211	0.01439	-20	-9.39%
	Total	83,576	0.01190	0.00416	0.00913	0.02519	2,106	100.00%	18,226	100.00%	30,832	63,133,012	3,572	0.04274	3,572	0.04274	0	0.00%
2012	Residential	31,082	0.01444	0.00580	0.01366	0.03390	1,054	49.41%	7,198	45.71%	13,201	55,561,443	2,136	0.06872	1,982	0.06378	154	7.75%
	Small L&P (incl. Streetlgts)	9,267	0.01181	0.00487	0.02032	0.03700	343	16.08%	1,590	10.10%	2,922	6,073,891	486	0.05244	645	0.06961	-159	-24.67%
	Medium L&P	9,312	0.01237	0.00511	0.00514	0.02262	211	9.88%	1,897	12.05%	3,603	596,298	429	0.04608	396	0.04257	33	8.26%
	Agriculture	**6,179**	**0.01016**	**0.00566**	**0.00864**	**0.02446**	**151**	**7.09%**	**1,576**	**10.01%**	**3,718**	**1,027,533**	**281**	**0.04556**	**284**	**0.04601**	**-3**	**-0.99%**
	E-19	14,618	0.01036	0.00355	0.00241	0.01632	239	11.18%	2,281	14.49%	3,565	212,188	465	0.03178	449	0.03070	16	3.52%
	E-20 (incl. Stdby)	15,604	0.00574	0.00181	0.00115	0.00870	136	6.37%	1,204	7.65%	1,766	15,403	215	0.01380	256	0.01638	-40	-15.71%
	Total	86,062	0.01136	0.00451	0.00892	0.02478	2,133	100.00%	15,747	100.00%	28,775	63,486,756	4,012	0.04662	4,012	0.04662	0	0.00%
2013	Residential	30,990	0.01780	0.00537	0.01377	0.03695	1,145	53.28%	9,471	50.29%	13,914	55,827,699	2,144	0.06919	2,150	0.06938	-6	-0.28%
	Small L&P (incl. Streetlgts)	9,078	0.01048	0.00566	0.02076	0.03689	335	15.59%	1,722	9.14%	4,223	6,081,643	476	0.05242	629	0.06928	-153	-24.33%
	Medium L&P	9,499	0.01117	0.00473	0.00505	0.02095	199	9.26%	2,083	11.06%	3,987	596,588	421	0.04436	374	0.03935	48	12.74%
	Agriculture	**7,022**	**0.01166**	**0.00553**	**0.00760**	**0.02479**	**174**	**8.10%**	**1,614**	**8.57%**	**4,012**	**1,026,492**	**300**	**0.04270**	**327**	**0.04656**	**-27**	**-8.28%**
	E-19	14,645	0.00875	0.00278	0.00240	0.01393	204	9.49%	2,453	13.02%	3,592	212,292	475	0.03244	383	0.02616	92	24.03%
	E-20 (incl. Stdby)	15,194	0.00329	0.00157	0.00118	0.00604	92	4.27%	1,491	7.92%	4,480	15,306	219	0.01440	172	0.01135	46	26.88%
	Total	86,428	0.01172	0.00424	0.00890	0.02486	2,149	100.00%	18,835	100.00%	34,207	63,760,020	4,035	0.04669	4,035	0.04669	0	0.00%
2014	Residential	29,835	0.01698	0.00575	0.01460	0.03733	1,114	45.37%	8,682	46.43%	14,111	56,151,146	1,534	0.05143	1,542	0.05167	-7	-0.47%
	Small L&P (incl. Streetlgts)	8,927	0.01185	0.00616	0.02168	0.03969	354	14.43%	1,905	10.19%	4,453	6,091,432	446	0.04993	490	0.05493	-45	-9.11%
	Medium L&P	9,388	0.01296	0.00477	0.00735	0.02508	235	9.59%	2,175	11.63%	3,597	500,851	354	0.03766	326	0.03471	28	8.50%
	Agriculture	**7,611**	**0.01343**	**0.00644**	**0.00725**	**0.02712**	**206**	**8.41%**	**1,760**	**9.41%**	**4,084**	**1,041,669**	**306**	**0.04020**	**286**	**0.03754**	**20**	**7.10%**
	E-19	14,585	0.00925	0.00283	0.01859	0.03067	447	18.22%	2,570	13.75%	3,591	321,016	539	0.03699	619	0.04245	-80	-12.87%
	E-20 (incl. Stdby)	15,897	0.00344	0.00152	0.00118	0.00614	98	3.98%	1,606	8.59%	4,444	15,459	219	0.01376	135	0.00850	84	61.86%
	Total	86,243	0.01190	0.00447	0.01210	0.02846	2,455	100.00%	18,698	100.00%	34,279	64,121,574	3,398	0.03940	3,398	0.03940	0	0.00%

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX F

ATTACHMENT 7

REVENUE ALLOCATION FOR OTHER COMPONENTS OF RATES

(NUCLEAR DECOMMISSIONING)

Pacific Gas & Electric Company

Attachment 7

2017 GRC - Phase II

Balancing Account Study (NON-BYPASSABLE CHARGES - Nuclear Decommissioning)

		Nuclear Decommissioning Forecast Versus Actual						
Year	Customer Class	Forecast Bundled & DA/CCA Sales	Allocated Forecast Revenue	Actual Bundled & DA/CCA Sales	Reallocated Revenue based on Actual Sales	Actual Revenue	Revenue Difference in Actual vs Reallocated	Revenue Difference in Reallocated vs Forecast
		(GWh)	($M)	(GWh)	($M)	($M)	($M)	($M)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Calculation:	Forecast	Forecast	Recorded	= (5 Ratio) x (4 Total)	Actual	= (7) - (6)	= (6) - (4)
2011	ND Rate ($/kWh)		0.00066		0.00068	0.00066		
	Residential	31,316	20.6	30,872	21.0	20.4	-0.67	0.45
	Small L&P (incl. Streetlgts)	10,043	6.6	9,160	6.2	6.0	-0.20	-0.36
	Medium L&P	11,547	7.6	9,486	6.5	6.3	-0.21	-1.13
	Agriculture	**5,208**	**3.4**	**4,691**	**3.2**	**3.1**	**-0.10**	**-0.23**
	E-19	13,074	8.6	14,726	10.0	9.7	-0.32	1.44
	E-20 (incl. Stdby)	15,422	10.1	14,641	10.0	9.7	-0.32	-0.16
	Total	86,611	57.0	83,576	57.0	55.2	-1.82	0.00
2012	ND Rate ($/kWh)		0.00055		0.00055	0.00055		
	Residential	32,162	17.7	31,082	17.0	17.1	0.05	-0.64
	Small L&P (incl. Streetlgts)	9,351	5.1	9,267	5.1	5.1	0.01	-0.06
	Medium L&P	9,772	5.4	9,312	5.1	5.1	0.01	-0.27
	Agriculture	**5,283**	**2.9**	**6,179**	**3.4**	**3.4**	**0.01**	**0.48**
	E-19	14,640	8.1	14,618	8.0	8.0	0.02	-0.03
	E-20 (incl. Stdby)	15,832	8.7	15,604	8.6	8.6	0.02	-0.15
	Total	87,040	47.2	86,062	47.2	47.3	0.13	-0.66
2013	ND Rate ($/kWh)		0.00050		0.00050	0.00050		
	Residential	32,196	16.0	30,990	15.4	15.5	0.09	-0.62
	Small L&P (incl. Streetlgts)	9,007	4.5	9,078	4.5	4.5	0.03	0.03
	Medium L&P	10,402	5.2	9,499	4.7	4.7	0.03	-0.45
	Agriculture	**5,046**	**2.5**	**7,022**	**3.5**	**3.5**	**0.02**	**0.98**
	E-19	13,897	6.9	14,645	7.3	7.3	0.04	0.36
	E-20 (incl. Stdby)	15,783	7.9	15,194	7.6	7.6	0.04	-0.30
	Total	86,331	43.0	86,428	43.0	43.2	0.25	0.00
2014	ND Rate ($/kWh)		0.00049		0.00050	0.00049		
	Residential	32,196	15.8	29,835	14.8	14.6	-0.22	-0.94
	Small L&P (incl. Streetlgts)	9,007	4.4	8,927	4.4	4.4	-0.06	0.03
	Medium L&P	10,402	5.1	9,388	4.7	4.6	-0.07	-0.43
	Agriculture	**5,046**	**2.5**	**7,611**	**3.8**	**3.7**	**-0.06**	**1.31**
	E-19	13,897	6.8	14,585	7.3	7.1	-0.11	0.44
	E-20 (incl. Stdby)	15,783	7.7	15,897	7.9	7.8	-0.12	0.17
	Total	86,331	42.9	86,243	42.9	42.3	-0.63	0.58

ADDENDUM

TO APPENDIX F

AGRICULTURAL PARTIES Concluded PG&E's *Agricultural Class Balancing Account Study*, While Fundamentally Flawed, Confirms the Need for a Mechanism to Address Agricultural Sales Variability

Based on an examination of Pacific Gas and Electric Company's (PG&E) *Agricultural Class Balancing Account Study Report (Report)*, the Agricultural Parties – Agricultural Energy Consumers Association (AECA) and California Farm Bureau Federation (CFBF) – have concluded that the Report demonstrates that sales forecast error is a significant problem for the agricultural class, but that PG&E's revenue allocation analysis, which was meant to quantify the class-specific revenue impact of the sales forecast error, is sufficiently flawed as to render it meaningless.

The Agricultural Parties are deeply troubled by the numerous errors in PG&E's revenue allocation analysis and request that the analysis be withdrawn. Despite a request to PG&E to correct its load data, significant errors remain, along with analytical mistakes. In addition, the study addresses just a four-year period, substantially limiting its usefulness because it does not capture the full sequence of hydrologic conditions that lead to over-collection of revenues from agricultural customers. That said, the Report does effectively support the Agricultural Parties' earlier findings that there is significant variance, in many years, between PG&E's forecasted and actual loads for agricultural customers.

PG&E's Data and Analytical Errors Undermine its Revenue Allocation Analysis

PG&E undertook an elaborate analysis to calculate revenue allocations for the years 2011 to 2014, relying on its marginal costs from the 2011 and 2014 GRCs and actual customer loads, so as to compare a "perfect" revenue allocation to the adopted revenue allocation and actual customer revenue.[1] Unfortunately, PG&E's analysis is undermined by numerous data and analytical errors that affect key analytical elements, rendering it unreliable and its results meaningless.

Load Data Errors

Errors in PG&E's load data are evident from an examination of Attachments 5 and 6 to the PG&E Report, which present the underlying data for PG&E's revenue allocation analysis. The Actual Sales data in Column 3 of each table follow expected patterns of year-to-year variation. However, the same cannot be said for the generation PCAF (Peak Capacity Allocation Factor) data in Column 9 of Attachment 5, and

[1] The Agricultural Parties do not believe such a short-term analysis is appropriate for addressing the question of whether, in the long-run, agricultural class load variability leads to a mis-assignment of revenue responsibility to the agricultural class. In PG&E's 2014 GRC Phase II, AECA submitted a revenue study as part of its testimony that covered the 2001 to 2013 period. The Agricultural Parties believe a longer-term study of that nature should be used to address the question of long-term revenue responsibility mis-assignment. However, in light of the significant errors in PG&E's analysis, questions of methodology are secondary to the significant data and analytical mistakes that render PG&E's analysis unreliable, and are not addressed further in these comments.

the distribution PCAF and Final Load Transformer (FLT) data in Columns 10 and 12 of Attachment 6.[2] PCAF and FLT loads are used to allocate generation capacity, primary distribution, secondary distribution, and distribution new business primary costs, and are therefore among the most important inputs to the revenue allocation study. Unfortunately, some of the trends evident from PG&E's PCAF and FLT datasets are simply not believable. For example:

- PCAF and FLT loads should have a fairly constant relationship to energy load, especially when averaged across a large number of customers; yet this is not always the case in PG&E's dataset. For example, from 2012 to 2013 the ratio of sales to FLT increases nearly 20% for the entire system (from 0.33 to 0.40) and rises 160% for E-20 and standby customers (from 0.11 to 0.29).
- Year-to-year load variations are much higher in PG&E's dataset than would be expected for large groups of customers. For example, the distribution PCAF varies from year-to-year by as much as 30% for residential customers;[3] the FLT, by as much as 44% for small L&P customers.[4] The significant load variation for these customer groups contrasts with even higher sales variation for agricultural customers in the same period. In other words, PCAF and FLT data patterns are contradicted by sales data patterns.
- The PCAF and FLT should generally move in lockstep; instead the relationships vary significantly across the years. For example, according to PG&E's data, the ratio of distribution PCAF to FLT for E-20 and standby customers was 0.68 in 2012 and 0.33 in 2013; the ratio of generation PCAF to FLT for this customer grouping fell from over 1.0 in 2011 and 2012 to around 0.5 in 2013 and 2014.
- Generation PCAFs should be no higher than distribution PCAFs, since generation PCAFs exclude direct access and Community Choice Aggregation loads that are included in distribution PCAFs; yet, in 2012, generation PCAFs in PG&E's dataset are higher than distribution PCAFs for seven of the nine customer classes, and for standby customers, generation PCAFs are more than 1,000 times higher than distribution PCAFs in 2013 and 2014.[5]

PG&E offers no explanation for these oddities, which, given their extreme nature, are reasonably viewed as errors unless evidence to the contrary is provided. The persistence of such mistakes is particularly disturbing in light of the fact that the release of PG&E's report was delayed from its original July deadline because of errors in this very data set that the Agricultural Parties brought to PG&E's attention. In other words, the dataset described above and used in PG&E's updated analysis was already corrected by PG&E and still appears to be so error-laden as to be unusable.

Given the many errors that persist in this dataset, it is evident that PG&E's fact-checking and correction processes have been grossly insufficient.[6] While intervenors can spot obvious data faults, the

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[2] PCAF is the sum of coincident peak loads for the class over a period that covers the highest system load hours; FLT is the sum of peak loads on the final line transformer for each customer. Distribution PCAFs include all customer load; generation PCAFs include only bundled customer load.

[3] Distribution PCAFs for residential customers are shown as 7,198 MW in 2012 and 9,471 MW in 2013 (Attachment 6, Table 2).

[4] FLTs for small L&P customers (including streetlights) are shown as 2,922 MW in 2012 and 4,223 MW in 2013 (Attachment 6, Table 2).

[5] Data from PG&E workpaper, "GRC comparison.xlsx," sheet "FLT & PCAF by Year," rows 3-16.

[6] There are additional mistakes in Attachment 6, Table 1, that appear to be typographical rather than errors with the data used in the analysis. For example, the E-19 distribution PCAF shown in Table 1 increases five-fold in 2013, then reverts back to more typical levels in 2014; however, it appears that the data used in PG&E's analysis differ in this case from the data shown in Table 1. (The errors described in the bulleted list above

Agricultural Parties do not have the information to do a thorough vetting without PG&E's assistance, nor do we have the necessary information to correct identifiable errors. Given that the Agricultural Parties have already attempted, unsuccessfully, to have PG&E review and correct its load data, and given that these erroneous data are key inputs to the revenue allocation calculations, we are in the untenable position of being cognizant of substantial errors without being able to offer possible curatives or identify a means to salvage the analysis. The Agricultural Parties conclude, therefore, that PG&E's results should be recognized as meaningless.

Analytical Errors

Given extensive errors in the load data used in the revenue allocation analysis, the Agricultural Parties did not conduct a thorough assessment of PG&E's study.[7] However, the limited assessment that we did conduct revealed additional material errors.

PG&E's revenue allocation analysis follows the utility's GRC Phase II revenue allocation approach, except that it uses actual loads for the years in question in place of a combination of historic loads from prior years and loads that were forecasted for that year. In other words, PG&E examined only a backcast of revenue requirements, instead of comparing that backcast to a forecast that would have been used in each GRC and ERRA to set rates.[8] Without such a comparison, it is impossible to determine to what extent revenue responsibilities fall out of balance. The section of analysis that the Agricultural Parties evaluated is the calculation of distribution primary, secondary, and new business revenue requirements.

In a typical GRC Phase II, PG&E calculates marginal costs for each of these cost elements and then assigns these costs to rate classes based on historic FLT and PCAF loads. PG&E divides the resulting revenue requirement for each rate class by historic sales to obtain per-kWh rates for each rate class, then multiplies these rates by a forecast of the sales for each rate class to obtain the revenue requirement forecast for each rate class. In other words, instead of assigning marginal costs to rate classes based on a forecast of FLT and PCAF loads, PG&E essentially assumes that the ratios of FLT to sales and of PCAF to sales will remain constant for each rate class, and calculates marginal cost responsibility based on historic FLT and PCAF loads, scaled for the difference between forecasted and historic sales.[9]

For the 2011-2014 analysis, PG&E has data on actual loads for each of the years in question; initial revenue responsibility can therefore be assigned directly by applying marginal costs to actual FLT and PCAF loads. PG&E's analysis does this step correctly, although the underlying data is questionable, but

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are associated with the data used in PG&E's analysis in workpaper, "GRC comparison.xlsx" and are not simply typographical errors in the report table.) In light of the other data issues identified, and PG&E's earlier correction of data errors in its report, the further errors in Table 1, even if they are simply typographical, are disconcerting, and further erode confidence in PG&E's Report.

[7] PG&E's workpapers for this Report include well more than 100 spreadsheet files; some of the links between files are not intact.

[8] The PG&E Report appears at first glance to compare the backcasted revenue requirements with the actual revenue requirements based on the GRC forecasts, but the data points being compared in PG&E's analysis are not truly comparable. For example, the backcasted revenue requirements are based on allocations derived from the GRC marginal costs, whereas the actual revenue requirements were based on allocations derived from the GRC marginal costs, adjusted for the adopted caps, and then further adjusted with annual ERRA rebalancing. For a meaningful comparison, the same analyses would need to be conducted to develop both the forward-looking and backcasted revenue allocations, with only the sales amounts differing from one analysis to the other.

[9] As seen in the data errors discussed in the previous section, this assumption of consistent relationships appears to be untrue in PG&E's dataset.

then proceeds with the remaining steps of the standard GRC Phase II process, meaning that after marginal costs are assigned based on actual FLT and PCAF loads, PG&E divides the resulting revenue requirements by actual sales, in place of historic sales, and then multiplies them by actual sales, in place of forecasted sales. These last two steps – dividing and then multiplying by actual sales – should cancel each other out, and the final revenue requirement should be the same as the initial revenue requirement obtained by assigning marginal costs to rate classes based on actual FLT and PCAF loads; however, on account of further analytical errors, this is not the case.

In the analysis reviewed, which uses 2014 GRC marginal costs with 2013 recorded data, there are numerous significant differences between the revenue requirements obtained after dividing and multiplying by actual sales ("final RRQ") and initial revenue responsibilities obtained from multiplying marginal costs by actual FLT and PCAF loads ("initial RRP"). For example, for distribution primary costs, the E-20-P final RRQ that are used in PG&E's Attachment 6 results tables are 45% lower than the initial RRP calculated for this customer class.[10] The reason for this difference is that the E-20-P initial RRP is divided by actual sales for both E-20-P and E-20-T customers to obtain a marginal cost rate, and then this rate is applied only to E-20-P actual sales, because transmission-level customers do not pay primary distribution costs. In other words, because the sales amount used to calculate the E-20-P rate is too high, because it erroneously includes E-20-T sales, the E-20-P rate is lower than needed to recover the E-20-P initial RRP, and the final RRQ is therefore lower than the actual E-20-P initial RRP. PG&E similarly included transmission-level kWh in calculating primary distribution rates for other classes, and included primary-level kWh in calculating secondary distribution rates. Since most non-secondary load is from large commercial and industrial customers, these mistakes result in an underestimate of cost responsibility for the large commercial and industrial customers.

There are additional errors, as well. A-10-P initial RRP is erroneously excluded from the calculation of initial RRP for Medium L&P customers.[11] The standby calculation uses Small L&P non-coincident peak load data from 2005-2007 instead of actual 2013 data, resulting in a final standby RR that is only 6% of the standby initial RRP for new business costs, and more than 500% of the standby initial RRP for primary and secondary distribution costs.[12]

Given the extent of errors identified and the Agricultural Parties' inability to develop corrected analyses without accurate load data, the Agricultural Parties did not take the time to evaluate the generation or other distribution revenue allocation calculations. It is clear from even the recognized data and analytical errors that PG&E's revenue allocation analysis should be dismissed as unreliable.

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[10] See PG&E workpaper "CONF_MCRev_GRC.xlsx" in folder Confidential Workpapers/GRC with actuals - all with 2014 MCs/2013 Actuals/AG Balancing Accounts Study - Model. For E-20-P customers, final RRQs are found in worksheet "MCR_Summary," cells B99:D99, and revenue responsibility is found in worksheet, "D_MCR_pkwh," cells B29:G29.

[11] See sheet, "D_MCR_pkwh": marginal cost rates for A-10 customers shown in J17-O17 are calculated by dividing A-10S marginal cost responsibility by the combined sales for A-10-S and A-10-P customers. The A-10-P cost responsibility is excluded from the final revenue requirement amounts.

[12] See workpaper, "Billing Determinants_GRC.xls," sheet "ForStandbyMCR," which is linked to sheet, "D_Stby_MCR" in the workpaper, "CONF_MCRev_GRC.xlsx."

PG&E's Historic Sales Data Verifies that Agricultural Load Variability is a Significant Issue

While the key analysis in PG&E's study, related to revenue allocation, is unreliable, there is one useful dataset in the Report: the dataset provided in Attachment 4, Table 1, which shows actual compared to forecasted sales for each major customer class from 1995 through 2014. A portion of this table is reproduced below, with the addition of a total line at the bottom that shows the difference over this 20-year period between actual and PG&E's forecasted sales for each of these customer classes.

Inspection of the annual data shows that the variance between forecasted and actual sales is, on the whole, much greater for the agricultural class than for other customer classes. For residential and commercial customers, the variance did not exceed ±8.0% in any year in this period; for industrial customers, the variance exceeded ±8.0% in just two of the 20 years, with a peak variance of -15% in 2002. By contrast, for agricultural customers, the variance exceeded ±8.0% in 12 years (i.e., two-thirds of the period), exceeded ±16.0% in nine years, and even exceeded ±30.0% in four years, including a 39% variance in 2013 and a 31% variance in 2014.

Moreover, the Total line reveals that the under- and overestimates do not cancel each other out for agricultural customers, instead continuing to accumulate against the class. For residential and commercial customers, actual sales over the 20-year period were within a few tenths of a percent of forecasted sales; for industrial customers, actual sales were 3.5% below forecasted;, and for agricultural customers, actual sales were more than 10% above forecasted sales. If, as the Agricultural Parties maintain, years of higher-than-expected sales from a customer class tend to result in an overcollection of revenue requirement from the class due to the overcollection of fixed costs, and vice versa in years of lower-than-expected sales, then it is likely that PG&E has over-collected revenue from agricultural customers over this period. Given that actual agricultural sales were 18%-39% higher than forecasted sales in the 2012-2014 period, the overcollection of revenue from agricultural customers in recent years is likely particularly substantial.

Table 1: Actual Sales Compared to PG&E's Forecast

	Residential	Commercial	Industrial	Agricultural
1995	-1.8%	-2.8%	-4.6%	-8.5%
1996	2.1%	-0.4%	-9.9%	2.4%
1997	1.9%	3.3%	-4.8%	4.6%
1998	1.2%	1.4%	-7.5%	-18.0%
1999	3.3%	5.3%	-4.1%	5.4%
2000	5.7%	8.0%	-4.3%	8.2%
2001	-6.7%	-2.7%	-2.9%	21.2%
2002	3.4%	3.0%	-15.1%	17.0%
2003	5.9%	2.9%	-7.7%	2.9%
2004	3.3%	1.6%	-2.6%	7.7%
2005	2.0%	-0.2%	-2.3%	-6.6%
2006	3.2%	-0.4%	-0.5%	-2.0%
2007	-0.7%	2.5%	0.6%	16.1%
2008	-0.3%	1.2%	4.3%	30.6%
2009	-2.2%	-5.8%	-6.5%	31.0%
2010	-0.4%	-2.3%	-6.7%	-0.2%
2011	-1.0%	-3.2%	-1.0%	-9.1%
2012	-3.1%	-1.1%	2.0%	17.9%
2013	-3.5%	0.6%	-0.3%	39.2%
2014	-6.2%	-3.6%	7.6%	31.0%
1995-2014 Total	0.1%	0.2%	-3.5%	10.4%

Conclusions

PG&E's report confirms the Agricultural Parties' assertion that sales forecast error is a much more substantial problem for the agricultural class than for other customer classes, that under- and over-forecasting errors do not cancel each other out for agricultural customers, and that this is a timely problem that has been particularly significant in recent years. These results are not surprising, given that agricultural use of electricity is highly sensitive to water conditions that cannot be accurately predicted in advance, and that energy use in dry years is not fully offset by savings in wet years.

The Agricultural Parties do not fault PG&E for its difficulty in forecasting agricultural sales; rather, the Agricultural Parties continue to request that PG&E and the Commission acknowledge that precipitation and water allocation forecasts far more prescient and timely than presently available would be required to accurately forecast agricultural sales, and that PG&E cannot therefore be expected to accurately forecast these sales. Instead, a new mechanism should be developed to adjust the PG&E sales forecast and resulting revenue allocation after information is available on water allocations for the year or other information that would lead to a more reliable agricultural sales forecast. The Agricultural Parties will develop such a proposal in its testimony in the current GRC Phase II proceeding, and looks forward to working with PG&E and other parties to shape it into a solution that is workable and fair to all parties.

Regardless, PG&E's calculation of the revenue implications of sales forecast error is, unfortunately, critically flawed and should be withdrawn. However, revenue results are not needed to move forward.

Sales forecasts are key inputs to the revenue allocation study, and impact revenue allocation. Given the magnitude of the sales forecast errors[13] shown in the Table 1 data for the agricultural class, it is clear that these errors have influenced revenue allocations, creating some amount of cost over-recovery. It is reasonable to conclude that the amount of the impact is likely substantial. Parties do not need to agree on the amount of this effect to agree on an approach to improve the revenue allocation process to explicitly account for agricultural forecasting error, with the aim of more accurately assessing cost responsibility for all customer classes.

[13] We use the term "error" non-pejoratively in this case; these are unavoidable errors inherent from natural system variability. No amount of research or analysis can fix these "errors" ahead of time.

PACIFIC GAS AND ELECTRIC COMPANY
2017 General Rate Case Phase II
Agricultural Data Reporting
Requirements

PG&E Data Request No.:	AG Parties_DataReporting_Compliance_PartC		
PG&E File Name:	GRC-2017-PhII_ AGParties_DataReporting_Part C (attachment 2)		
Request Date:	August 9, 2018, D.18-08-013,	Requester DR No.: MC/RA settlement	AG Data Reporting Requirements
Date Sent:	February 11, 2019	Requesting Party:	AECA and CFBF
PG&E Witness:	Keith Coyne	Requester:	

Background

In compliance with the Marginal Cost and Revenue Allocation Settlement in PG&E's 2017 GRC Phase II proceeding, as approved by D.18-08-013, PG&E is providing the data specified in Attachment 2, Part C, to that settlement in the Excel attachments to this response. The confidential data for Part C in Question 2, part (g), is being provided under the 2017 GRC Phase II NDA.

Question Part C:

C. Historical Demand Data (to be provided on an annual basis for the 2008-2015 period for each agricultural rate class/schedule)

Historical demand data specified in Part C will be provided to AECA and CFBF in a spreadsheet format within six months of the date of a Commission decision approving this settlement. Notice of the availability of historical demand data will be provided to the California Large Energy Consumers' Association (CLECA) and the Energy Producers and Users Coalition (EPUC). The notice will identify what data is being provided by reference to the alpha and numerical designations in the *AG Data Reporting Requirements,* and the year of the data.

1) Generation demand, as available based on billing data:
   a) Maximum demand summer
   b) Maximum demand winter
   c) Maximum peak demand summer
   d) Maximum part-peak demand summer
   e) Maximum part-peak demand winter
   f) Summer and winter generation PCAFs, using class definitions in place at the time for each year[1]

2) Distribution demand, as available based on billing data:
   a) Maximum demand summer
   b) Maximum demand winter
   c) Maximum peak demand summer
   d) Maximum part-peak demand summer
   e) Maximum part-peak demand winter

[1] PG&E will identify which rate schedules are included in each class definition for the historic PCAF and FLT data.

f) Summer and winter distribution PCAFs, using class definitions in place at the time for each year
g) Distribution FLT load, using class definitions in place at the time for each year

Confidentiality

1) Customer specific information shall be anonymized and aggregated to meet the Commission's aggregation requirements in D.14-05-016, at a minimum. Where the aggregation standards cannot be met, the customer information will be anonymized, and access to the anonymized information will be treated as confidential and provided pursuant to the 2017 GRC II NDA to the party and its consultants who have executed the non-disclosure agreement for the 2017 GRC II case. If it is still possible to identify the customer given the anonymized information, the customer information will not be provided to anyone except Commission staff.
2) PG&E may designate other confidential information as subject to the non-disclosure agreement, and the information will only be provided to the party and its consultants who have executed the non-disclosure agreement for the 2017 GRC II case, and as consistent with the terms of that NDA. Any information provided under this agreement that PG&E designates as subject to the NDA will be clearly marked with this designation.
3) With respect to confidential data provided under the *AG Data Reporting Requirements*, PG&E will not send the notice provided under Section 5 of the 2017 GRC II NDA before issues for which the data is used in PG&E's next GRC II case are resolved there.
4) Submission or use of confidential data that was received pursuant to this agreement for PG&E's next GRC II case will require appropriate confidentiality protections in that case, including NDAs and/or motions for confidential treatment in that docket. Examples would be testimony, work papers, data responses, reports, etc., that include confidential information.

Answer Part C:

Question 1, part (a) – (e) and Question 2, part (a) through (e)

Demand information for bundled customers (i.e., generation) in response to Question 1, part (a) through (e); and demand information for combined bundled and Direct Access and Community Choice Aggregation (DA/CCA) customers (i.e., distribution) in response to Question 2, part (a) through (e), is provided in GRC-2017-PhII_AGParties_DataReporting_PartC-Atch1. This information is not confidential.

Question 1, part (f)

Generation PCAF data for 2008 through 2015 in response to Question 1 part (f) is provided in GRC-2017-PhII_AGParties_DataReporting_PartC-Atch2. This information is not confidential.

Agricultural Generation (or System) PCAFs in 2008 were only available including Schedule E-37. In 2009 through 2012, Schedule E-37 was included with commercial and industrial rate schedules. Beginning in 2013, Schedule E-37 is shown separately.

The mapping of rate schedules to class grouping is shown below. Note that the Agricultural class groupings changed in 2013.

2008 through 2012					
Class Grouping	**Rate Schedules**				
AGRA	AGRA	AGVA	AG4A		
AGRB	AGRB	AGVB	AG4B	AG4C	
AG1A	AG1A				
AG1B	AG1B				
AG5A	AG5A				
AG5B	AG5B	AG5C	E37P	E37S	E37T
Beginning 2013					
Class Grouping	**Rate Schedules**				
AGA	AG1A	AG4A	AG5A	AGRA	AGVA
AGBSm	AG1B	AG4B	AG4C	AGRB	AGVB
AGBLg	AG5B	AG5C	AGICE		

Question 2, part (f)

Distribution PCAF in response to Question 2 part (f) is provided in GRC-2017-PhII_AGParties_DataReporting_PartC-Atch3. This information is not confidential. Please note that the treatment of Schedule E-37 and the mapping of rate schedule to class grouping is the same for distribution PCAF data as it is for Generation PCAF data described above.

Question 2, part (g) : Attachment 4 Contains Confidential Customer Information Provided Pursuant to the NDA in A.16-06-013.

Final Line Transformer load in response to Question 2 part (g) is provided in GRC-2017-PhII_AGParties_DataReporting_PartC-Atch4CONF. The data provided in response to this question is non-coincident demand. In the case of agricultural customers, final line transformer demand and non-coincident demand are the same. For residential and small commercial customers however, non-coincident demand is further diversified to calculate final line transformer demand. PG&E has not provided final line transformer demand for residential and small commercial customers because the request is specific to the agricultural class/schedules. Please note that the treatment of Schedule E-37 and the mapping of rate schedule to class grouping is the same for final line transformer demand data as it is for Distribution and Generation PCAF data described above. This data response contains confidential information. Attachment 4 will be sent when available, after PG&E completes the identification of confidential data in cells to be shaded gray.

PACIFIC GAS AND ELECTRIC COMPANY
2017 General Rate Case Phase II
Agricultural Data Reporting
Requirements

PG&E Data Request No.:	AG Parties_DataReporting_Compliance_PartC-SUPP01		
PG&E File Name:	GRC-2017-PhII_ AGParties_DataReporting_Part C-SUPP01		
Request Date:	May 13, 2019	Requester DR No.: MC/RA settlement	AG Data Reporting Requirements
Date Sent:	August 1, 2019	Requesting Party:	AECA and CFBF
PG&E Witness:	Keith Coyne	Requester:	Richard McCann

Question Part C – SUPP01:

We were looking through the data responses and see that we do not have historic energy load data by rate class. I'm not sure if that was an oversight in our request, or whether it hasn't been delivered yet. If we failed to request it, please add it to our list.

Thank you

Richard McCann

Answer Part C, SUPP01:

PG&E agrees that the Agricultural Data Reporting Requirements specified in Part C of Attachment 2, *Agreed Data Relating to Agricultural Sales Variability Issues*, as set forth in the *Settlement Agreement on Marginal Cost and Revenue Allocation Issues* adopted in D.18-08-013 in PG&E's 2017 GRC Phase II proceeding, did not specify or require that historical kWh sales data by rate class be provided.

However, as requested above, PG&E has compiled this data for the years 2008 through 2015, consistent with Part C data requirements. In addition, PG&E has included data now available for the years 2016 through 2018. Please see the following attachment:

GRC-2017-PhII_AGParties_DataReporting_PartC-SUPP01-Atch01.xls.

The above data file contains one tab for each calendar year, 2008 through 2018, with each year showing a breakdown of bundled kWh sales, versus Direct Access/Community Choice Aggregation (DA/CCA) kWh sales, by applicable customer class. The source of this data is Electric History (EH) Sheet data produced by PG&E's Revenue Accounting Department.

PACIFIC GAS AND ELECTRIC COMPANY
2017 General Rate Case Phase II
Compliance Requirement

PG&E Data Request No.:	AG Parties_DataRep_Compliance-2016_PartA/B_A-Q01_B-Q01		
PG&E File Name:	GRC-2017-PhII_DR_AGParties_DataRep_A-Q01_B-Q01		
Request Date:	August 9, 2018, D.18-08-013	Requester DR No.: MC/RA Settlement	Ag Data Reporting Requirements
Date Sent:	April 1, 2019	Requesting Party:	AECA and CFBF
PG&E Witness:	Keith Coyne	Requester:	

Tracking data specified in Sections A and B will be reported to AECA and CFBF annually in a spreadsheet format, lagged by at least 90 days, or as the data become available. If data will not be available within the 90-day target, notification will be sent to AECA and CFBF specifying a date when the data will be provided. Notice of the availability of tracking data will be provided to CLECA and to EPUC. The notice will identify what data is being provided by reference to the alpha and numerical designations in the *AG Data Reporting Requirements.* Tracking data will be provided for the years 2016 through 2019.

Part A Question 1: 2016 Generation Data Tracking

1) Forecast Data from Advice Letters[1]
   a) Forecasts of bundled sales and DA/CCA sales for each agricultural rate schedule (excluding E-37 customers) from the Annual Electric True Up Advice Letter (AET)
   b) Forecasts of system total bundled sales and DA/CCA sales from the AET
   c) Forecasts of generation revenue and Power Charge Indifference Adjustment (PCIA) revenue[2] from each agricultural rate schedule (excluding E-37 customers) from the AET and any other advice letters that modify the generation or PCIA rate
   d) Forecasts of total generation revenue and PCIA revenue from the AET and any other advice letters that modify the generation or PCIA rate
   e) Average generation rates and PCIA rates for each agricultural rate schedule (excluding E-37 customers) from the AET and any other advice letters that modify the generation or PCIA rate
   f) System-average generation rate and PCIA rate from the AET and any other advice letters that modify the PCIA rate

[1] For agricultural class data, advice letter data will be adjusted to remove Schedule E-37 from the agricultural class.
[2] References to the PCIA incorporate any PCIA successor charge that may be adopted.

Part B Question 1: 2016 Distribution Tracking

1) Forecast Data from Advice Letters[3]
   a) Average distribution rate for each agricultural rate schedule (excluding E-37) from the AET and any other advice letters that modify the distribution rate
   b) Distribution revenue from each agricultural rate schedule (excluding E-37) from the AET and any other advice letters that modify the distribution rate
   c) System-average distribution rate from the AET and any other advice letters that modify the distribution rate
   d) System total distribution revenue from the AET and any other advice letters that modify the distribution rate
   e) Average New System Generation Charge (NSGC) rate for each agricultural rate schedule (excluding E-37) from the AET and any other advice letters that modify the NSGC rate
   f) Total NSGC revenue from each agricultural rate schedule (excluding E-37) from the AET and any other advice letters that modify the NSGC rate
   g) System-average NSGC rate from the AET and any other advice letters that modify the NSGC rate
   h) System total NSGC revenue from the AET and any other advice letters that modify the NSGC rate

Confidentiality: Responses to Part A, Question 1 and Part B, Question 1 are not confidential.

Answer to Part A, Question 1 and Part B, Question 1.

Responses for 2016 are contained in the attached file GRC-2017-PhII_DR_AGParties_DataRep2016_A-Q01_B-Q01Atch01.

[3] For agricultural class data, advice letter data will be adjusted to remove Schedule E-37 from the agricultural class.

PACIFIC GAS AND ELECTRIC COMPANY
2017 General Rate Case Phase II
Compliance Requirement

PG&E Data Request No.:	AG Parties_DataRep_Compliance-2016_PartA/B_A-Q04_B-Q04		
PG&E File Name:	GRC-2017-PhII_DR_AGParties_DataRep_2016_A-Q04_B-Q04		
Request Date:	August 9, 2018, D.18-08-013	Requester DR No.: MC/RA Settlement	Ag Data Reporting Requirements
Date Sent:	April 1, 2019	Requesting Party:	AECA and CFBF
PG&E Witness:	Keith Coyne	Requester:	

Tracking data specified in Sections A and B will be reported to AECA and CFBF annually in a spreadsheet format, lagged by at least 90 days, or as the data become available. If data will not be available within the 90-day target, notification will be sent to AECA and CFBF specifying a date when the data will be provided. Notice of the availability of tracking data will be provided to CLECA and to EPUC. The notice will identify what data is being provided by reference to the alpha and numerical designations in the *AG Data Reporting Requirements.* Tracking data will be provided for the years 2016 through 2019.

Part A, Question 4: 2016 Generation Recorded Data

4. Recorded Data during the Tracking Period
a) Monthly bundled sales and DA/CCA sales for each rate schedule
b) Hourly bundled sales for each agricultural rate schedule, where available
c) Hourly DA/CCA sales for each agricultural rate schedule, where available
d) Hourly PG&E system-total bundled sales, where available
e) Hourly PG&E total DA/CCA sales, where available
f) DA/CCA PCIA revenue from each agricultural rate schedule
g) Total PCIA revenue
h) Bundled generation revenue from each agricultural rate schedule
i) Total bundled generation revenue
j) Summer and winter generation PCAFs for each rate schedule
k) Bundled agricultural demand from each rate schedule, as available based on billing data:
    i) Maximum demand summer
    ii) Maximum demand winter
    iii) Maximum peak demand summer
    iv) Maximum part-peak demand summer
    v) Maximum part-peak demand winter

Part B, Question 4, 2016 Distribution Recorded Data

4. Recorded data during the Tracking Period:

a) Number of meters (averaged over period) for each agricultural rate schedule
b) Number of new connects for each agricultural rate schedule
c) Number of disconnects for each agricultural rate schedule
d) Summer and winter distribution PCAFs for each rate schedule
e) Distribution FLTs for each rate schedule
f) Distribution agricultural demand from each rate schedule, as available based on billing data:
    i) Maximum demand summer
    ii) Maximum demand winter
    iii) Maximum peak demand summer
    iv) Maximum part-peak demand summer
    v) Maximum part-peak demand winter
g) Distribution revenue from each agricultural rate schedule
h) System-total distribution revenue
i) NSGC revenue from each agricultural rate schedule
j) System-total NSGC revenue

Confidentiality

1) Customer specific information shall be anonymized and aggregated to meet the Commission's aggregation requirements in D.14-05-016, at a minimum. Where the aggregation standards cannot be met, the customer information will be anonymized, and access to the anonymized information will be treated as confidential and provided pursuant to the 2017 GRC II NDA to the party and its consultants who have executed the non-disclosure agreement for the 2017 GRC II case. If it is still possible to identify the customer given the anonymized information, the customer information will not be provided to anyone except Commission staff.
2) PG&E may designate other confidential information as subject to the non-disclosure agreement, and the information will only be provided to the party and its consultants who have executed the non-disclosure agreement for the 2017 GRC II case, and as consistent with the terms of that NDA. Any information provided under this agreement that PG&E designates as subject to the NDA will be clearly marked with this designation.
3) With respect to confidential data provided under the *AG Data Reporting Requirements*, PG&E will not send the notice provided under Section 5 of the 2017 GRC II NDA before issues for which the data is used in PG&E's next GRC II case are resolved there.
4) Submission or use of confidential data that was received pursuant to this agreement for PG&E's next GRC II case will require appropriate confidentiality protections in that case, including NDAs and/or motions for confidential treatment in that docket. Examples would be testimony, work papers, data responses, reports, etc., that include confidential information.

Answer Part A, Question 4. Generation Tracking. Each tab of the attached file GRC-2017-PhII_DR_AGParties_DataRep_2016_A-Q04_B-Q04-Atch01 is labeled with the associated subpart. Hourly sales for each agricultural schedule and for the system are provided where available. Hourly data was summed from interval data. Sales that were not available on an interval basis are also provided. Generation PCAFs developed for this response were based on the methods used in the past for generating PCAF values. PG&E may revise its method in its upcoming 2020 GRC Phase II proceeding. This information is not confidential.

Answer Part B, Question 4. Distribution Tracking. Each tab of the attached file GRC-2017-PhII_DR_AGParties_DataRep_2016_A-Q04_B-Q04-Atch02 is labeled with the associated subpart. All subparts to this question except subpart e are included. Information in Attachment 2 is not confidential. Distribution PCAFs developed for this response were based on the methods used in the past for generating PCAF values and are provided before application of loss factors. PG&E has provided loss factors from the prior GRC for reference. PG&E may revise its method in its upcoming 2020 GRC Phase II proceeding. With regard to subparts b and c, a determination of connections was based on the first service at a premise, and disconnections were determined based on the date the last service at a premise ended. PG&E's estimate of new connections for purposes of developing marginal cost in the 2020 GRC Phase II may vary from the values presented herein.

Answer Part B, Question 4, subpart e. **This response contains confidential customer information provided pursuant to the NDA in A. 16-06-013.** Information provided in response to this request is in GRC-2017-PhII_DR_AGParties_DataRep_2016_A-Q04_B-Q04-Atch03CONF. Annual non-coincident demand by schedule is provided in response to this request. For reference, PG&E has also provided residential and small commercial diversity factors from the last GRC which were used to develop FLT loads. Non-coincident demand and diversity factors provided in this response were based on the methods used in the past for generating FLT values. PG&E may revise its method in its upcoming 2020 GRC Phase II proceeding.

PACIFIC GAS AND ELECTRIC COMPANY
2017 General Rate Case Phase II
Compliance Requirement

PG&E Data Request No.:	AG Parties_DataRep_Compliance-2016_PartA/B_A-Q04_B-Q04		
PG&E File Name:	GRC-2017-PhII_DR_AGParties_DataRep_2016_A-Q04_B-Q04		
Request Date:	August 9, 2018, D.18-08-013	Requester DR No.: MC/RA Settlement	Ag Data Reporting Requirements
Date Sent:	April 1, 2019	Requesting Party:	AECA and CFBF
PG&E Witness:	Keith Coyne	Requester:	

Tracking data specified in Sections A and B will be reported to AECA and CFBF annually in a spreadsheet format, lagged by at least 90 days, or as the data become available. If data will not be available within the 90-day target, notification will be sent to AECA and CFBF specifying a date when the data will be provided. Notice of the availability of tracking data will be provided to CLECA and to EPUC. The notice will identify what data is being provided by reference to the alpha and numerical designations in the *AG Data Reporting Requirements.* Tracking data will be provided for the years 2016 through 2019.

Part A, Question 4: 2016 Generation Recorded Data

4. Recorded Data during the Tracking Period
a) Monthly bundled sales and DA/CCA sales for each rate schedule
b) Hourly bundled sales for each agricultural rate schedule, where available
c) Hourly DA/CCA sales for each agricultural rate schedule, where available
d) Hourly PG&E system-total bundled sales, where available
e) Hourly PG&E total DA/CCA sales, where available
f) DA/CCA PCIA revenue from each agricultural rate schedule
g) Total PCIA revenue
h) Bundled generation revenue from each agricultural rate schedule
i) Total bundled generation revenue
j) Summer and winter generation PCAFs for each rate schedule
k) Bundled agricultural demand from each rate schedule, as available based on billing data:
    i) Maximum demand summer
    ii) Maximum demand winter
    iii) Maximum peak demand summer
    iv) Maximum part-peak demand summer
    v) Maximum part-peak demand winter

Part B, Question 4, 2016 Distribution Recorded Data

4. Recorded data during the Tracking Period:

a) Number of meters (averaged over period) for each agricultural rate schedule
b) Number of new connects for each agricultural rate schedule
c) Number of disconnects for each agricultural rate schedule
d) Summer and winter distribution PCAFs for each rate schedule
e) Distribution FLTs for each rate schedule
f) Distribution agricultural demand from each rate schedule, as available based on billing data:
    i) Maximum demand summer
    ii) Maximum demand winter
    iii) Maximum peak demand summer
    iv) Maximum part-peak demand summer
    v) Maximum part-peak demand winter
g) Distribution revenue from each agricultural rate schedule
h) System-total distribution revenue
i) NSGC revenue from each agricultural rate schedule
j) System-total NSGC revenue

Confidentiality

1) Customer specific information shall be anonymized and aggregated to meet the Commission's aggregation requirements in D.14-05-016, at a minimum. Where the aggregation standards cannot be met, the customer information will be anonymized, and access to the anonymized information will be treated as confidential and provided pursuant to the 2017 GRC II NDA to the party and its consultants who have executed the non-disclosure agreement for the 2017 GRC II case. If it is still possible to identify the customer given the anonymized information, the customer information will not be provided to anyone except Commission staff.
2) PG&E may designate other confidential information as subject to the non-disclosure agreement, and the information will only be provided to the party and its consultants who have executed the non-disclosure agreement for the 2017 GRC II case, and as consistent with the terms of that NDA. Any information provided under this agreement that PG&E designates as subject to the NDA will be clearly marked with this designation.
3) With respect to confidential data provided under the *AG Data Reporting Requirements*, PG&E will not send the notice provided under Section 5 of the 2017 GRC II NDA before issues for which the data is used in PG&E's next GRC II case are resolved there.
4) Submission or use of confidential data that was received pursuant to this agreement for PG&E's next GRC II case will require appropriate confidentiality protections in that case, including NDAs and/or motions for confidential treatment in that docket. Examples would be testimony, work papers, data responses, reports, etc., that include confidential information.

Answer Part A, Question 4. Generation Tracking. Each tab of the attached file GRC-2017-PhII_DR_AGParties_DataRep_2016_A-Q04_B-Q04-Atch01 is labeled with the associated subpart. Hourly sales for each agricultural schedule and for the system are provided where available. Hourly data was summed from interval data. Sales that were not available on an interval basis are also provided. Generation PCAFs developed for this response were based on the methods used in the past for generating PCAF values. PG&E may revise its method in its upcoming 2020 GRC Phase II proceeding. This information is not confidential.

Answer Part B, Question 4. Distribution Tracking. Each tab of the attached file GRC-2017-PhII_DR_AGParties_DataRep_2016_A-Q04_B-Q04-Atch02 is labeled with the associated subpart. All subparts to this question except subpart e are included. Information in Attachment 2 is not confidential. Distribution PCAFs developed for this response were based on the methods used in the past for generating PCAF values and are provided before application of loss factors. PG&E has provided loss factors from the prior GRC for reference. PG&E may revise its method in its upcoming 2020 GRC Phase II proceeding. With regard to subparts b and c, a determination of connections was based on the first service at a premise, and disconnections were determined based on the date the last service at a premise ended. PG&E's estimate of new connections for purposes of developing marginal cost in the 2020 GRC Phase II may vary from the values presented herein.

Answer Part B, Question 4, subpart e. **This response contains confidential customer information provided pursuant to the NDA in A. 16-06-013.** Information provided in response to this request is in GRC-2017-PhII_DR_AGParties_DataRep_2016_A-Q04_B-Q04-Atch03CONF. Annual non-coincident demand by schedule is provided in response to this request. For reference, PG&E has also provided residential and small commercial diversity factors from the last GRC which were used to develop FLT loads. Non-coincident demand and diversity factors provided in this response were based on the methods used in the past for generating FLT values. PG&E may revise its method in its upcoming 2020 GRC Phase II proceeding.

PACIFIC GAS AND ELECTRIC COMPANY
2017 General Rate Case Phase II
Compliance Requirement

PG&E Data Request No.:	AG Parties_DataRep_Compliance-2017_PartA/B_A-Q01_B-Q01		
PG&E File Name:	GRC-2017-PhII_DR_AGParties_DataRep_2017-A-Q01_B-Q01		
Request Date:	August 9, 2018, D.18-08-013	Requester DR No.: MC/RA Settlement	Ag Data Reporting Requirements
Date Sent:	April 1, 2019	Requesting Party:	AECA and CFBF
PG&E Witness:	Keith Coyne	Requester:	

Tracking data specified in Sections A and B will be reported to AECA and CFBF annually in a spreadsheet format, lagged by at least 90 days, or as the data become available. If data will not be available within the 90-day target, notification will be sent to AECA and CFBF specifying a date when the data will be provided. Notice of the availability of tracking data will be provided to CLECA and to EPUC. The notice will identify what data is being provided by reference to the alpha and numerical designations in the *AG Data Reporting Requirements.* Tracking data will be provided for the years 2016 through 2019.

Part A Question 1: 2017 Generation Data Tracking

1) Forecast Data from Advice Letters[1]
   a) Forecasts of bundled sales and DA/CCA sales for each agricultural rate schedule (excluding E-37 customers) from the Annual Electric True Up Advice Letter (AET)
   b) Forecasts of system total bundled sales and DA/CCA sales from the AET
   c) Forecasts of generation revenue and Power Charge Indifference Adjustment (PCIA) revenue[2] from each agricultural rate schedule (excluding E-37 customers) from the AET and any other advice letters that modify the generation or PCIA rate
   d) Forecasts of total generation revenue and PCIA revenue from the AET and any other advice letters that modify the generation or PCIA rate
   e) Average generation rates and PCIA rates for each agricultural rate schedule (excluding E-37 customers) from the AET and any other advice letters that modify the generation or PCIA rate
   f) System-average generation rate and PCIA rate from the AET and any other advice letters that modify the PCIA rate

[1] For agricultural class data, advice letter data will be adjusted to remove Schedule E-37 from the agricultural class.
[2] References to the PCIA incorporate any PCIA successor charge that may be adopted.

Part B Question 1: 2017 Distribution Tracking

1) Forecast Data from Advice Letters[3]
   a) Average distribution rate for each agricultural rate schedule (excluding E-37) from the AET and any other advice letters that modify the distribution rate
   b) Distribution revenue from each agricultural rate schedule (excluding E-37) from the AET and any other advice letters that modify the distribution rate
   c) System-average distribution rate from the AET and any other advice letters that modify the distribution rate
   d) System total distribution revenue from the AET and any other advice letters that modify the distribution rate
   e) Average New System Generation Charge (NSGC) rate for each agricultural rate schedule (excluding E-37) from the AET and any other advice letters that modify the NSGC rate
   f) Total NSGC revenue from each agricultural rate schedule (excluding E-37) from the AET and any other advice letters that modify the NSGC rate
   g) System-average NSGC rate from the AET and any other advice letters that modify the NSGC rate
   h) System total NSGC revenue from the AET and any other advice letters that modify the NSGC rate

Confidentiality: Responses to Part A, Question 1 and Part B, Question 1 are not confidential.

Answer to Part A, Question 1 and Part B, Question 1.

Responses for 2017 are contained in the attached file GRC-2017-PhII_DR_AGParties_DataRep2017-A-Q01_B-Q01Atch01.

[3] For agricultural class data, advice letter data will be adjusted to remove Schedule E-37 from the agricultural class.

PACIFIC GAS AND ELECTRIC COMPANY
2017 General Rate Case Phase II
Compliance Requirement

PG&E Data Request No.:	AG Parties_DataRep_Compliance-2017_PartA/B_A-Q04_B-Q04		
PG&E File Name:	GRC-2017-PhII_DR_AGParties_DataRep_2017-A-Q04_B-Q04		
Request Date:	August 9, 2018, D.18-08-013	Requester DR No.: MC/RA Settlement	Ag Data Reporting Requirements
Date Sent:	April 1, 2019	Requesting Party:	AECA and CFBF
PG&E Witness:	Keith Coyne	Requester:	

Tracking data specified in Sections A and B will be reported to AECA and CFBF annually in a spreadsheet format, lagged by at least 90 days, or as the data become available. If data will not be available within the 90-day target, notification will be sent to AECA and CFBF specifying a date when the data will be provided. Notice of the availability of tracking data will be provided to CLECA and to EPUC. The notice will identify what data is being provided by reference to the alpha and numerical designations in the *AG Data Reporting Requirements.* Tracking data will be provided for the years 2016 through 2019.

Part A, Question 4: 2017 Generation Recorded Data

4. Recorded Data during the Tracking Period
a) Monthly bundled sales and DA/CCA sales for each rate schedule
b) Hourly bundled sales for each agricultural rate schedule, where available
c) Hourly DA/CCA sales for each agricultural rate schedule, where available
d) Hourly PG&E system-total bundled sales, where available
e) Hourly PG&E total DA/CCA sales, where available
f) DA/CCA PCIA revenue from each agricultural rate schedule
g) Total PCIA revenue
h) Bundled generation revenue from each agricultural rate schedule
i) Total bundled generation revenue
j) Summer and winter generation PCAFs for each rate schedule
k) Bundled agricultural demand from each rate schedule, as available based on billing data:
    i) Maximum demand summer
    ii) Maximum demand winter
    iii) Maximum peak demand summer
    iv) Maximum part-peak demand summer
    v) Maximum part-peak demand winter

Part B, Question 4, 2017 Distribution Recorded Data

4. Recorded data during the Tracking Period:

a) Number of meters (averaged over period) for each agricultural rate schedule
b) Number of new connects for each agricultural rate schedule
c) Number of disconnects for each agricultural rate schedule
d) Summer and winter distribution PCAFs for each rate schedule
e) Distribution FLTs for each rate schedule
f) Distribution agricultural demand from each rate schedule, as available based on billing data:
    i) Maximum demand summer
    ii) Maximum demand winter
    iii) Maximum peak demand summer
    iv) Maximum part-peak demand summer
    v) Maximum part-peak demand winter
g) Distribution revenue from each agricultural rate schedule
h) System-total distribution revenue
i) NSGC revenue from each agricultural rate schedule
j) System-total NSGC revenue

Confidentiality

1) Customer specific information shall be anonymized and aggregated to meet the Commission's aggregation requirements in D.14-05-016, at a minimum. Where the aggregation standards cannot be met, the customer information will be anonymized, and access to the anonymized information will be treated as confidential and provided pursuant to the 2017 GRC II NDA to the party and its consultants who have executed the non-disclosure agreement for the 2017 GRC II case. If it is still possible to identify the customer given the anonymized information, the customer information will not be provided to anyone except Commission staff.
2) PG&E may designate other confidential information as subject to the non-disclosure agreement, and the information will only be provided to the party and its consultants who have executed the non-disclosure agreement for the 2017 GRC II case, and as consistent with the terms of that NDA. Any information provided under this agreement that PG&E designates as subject to the NDA will be clearly marked with this designation.
3) With respect to confidential data provided under the *AG Data Reporting Requirements*, PG&E will not send the notice provided under Section 5 of the 2017 GRC II NDA before issues for which the data is used in PG&E's next GRC II case are resolved there.
4) Submission or use of confidential data that was received pursuant to this agreement for PG&E's next GRC II case will require appropriate confidentiality protections in that case, including NDAs and/or motions for confidential treatment in that docket. Examples would be testimony, work papers, data responses, reports, etc., that include confidential information.

Answer Part A, Question 4. Generation Tracking. Each tab of the attached file GRC-2017-PhII_DR_AGParties_DataRep_2017_A-Q04_B-Q04-Atch01 is labeled with the associated subpart. Hourly sales for each agricultural schedule and for the system are provided where available. Hourly data was summed from interval data. Sales that were not available on an interval basis are also provided. Generation PCAFs developed for this response were based on the methods used in the past for generating PCAF values. PG&E may revise its method in its upcoming 2020 GRC Phase II proceeding. This information is not confidential.

Answer Part B, Question 4. Distribution Tracking. Each tab of the attached file GRC-2017-PhII_DR_AGParties_DataRep_2017_A-Q04_B-Q04-Atch02 is labeled with the associated subpart. All subparts to this question except subpart e are included. Information in Attachment 2 is not confidential. Distribution PCAFs developed for this response were based on the methods used in the past for generating PCAF values and are provided before application of loss factors. PG&E has provided loss factors from the prior GRC for reference. PG&E may revise its method in its upcoming 2020 GRC Phase II proceeding. With regard to subparts b and c, a determination of connections was based on the first service at a premise, and disconnections were determined based on the date the last service at a premise ended. PG&E's estimate of new connections for purposes of developing marginal cost in the 2020 GRC Phase II may vary from the values presented herein.

Answer Part B, Question 4, subpart e. **This response contains confidential customer information provided pursuant to the NDA in A. 16-06-013.** Information provided in response to this request is in GRC-2017-PhII_DR_AGParties_DataRep_2017_A-Q04_B-Q04-Atch03CONF. Annual non-coincident demand by schedule is provided in response to this request. For reference, PG&E has also provided residential and small commercial diversity factors from the last GRC which were used to develop FLT loads. Non-coincident demand and diversity factors provided in this response were based on the methods used in the past for generating FLT values. PG&E may revise its method in its upcoming 2020 GRC Phase II proceeding.

PACIFIC GAS AND ELECTRIC COMPANY
2017 General Rate Case Phase II
Compliance Requirement

PG&E Data Request No.:	AG Parties_DataRep_Compliance-2017_PartA/B_A-Q04_B-Q04		
PG&E File Name:	GRC-2017-PhII_DR_AGParties_DataRep_2017-A-Q04_B-Q04		
Request Date:	August 9, 2018, D.18-08-013	Requester DR No.: MC/RA Settlement	Ag Data Reporting Requirements
Date Sent:	April 1, 2019	Requesting Party:	AECA and CFBF
PG&E Witness:	Keith Coyne	Requester:	

Tracking data specified in Sections A and B will be reported to AECA and CFBF annually in a spreadsheet format, lagged by at least 90 days, or as the data become available. If data will not be available within the 90-day target, notification will be sent to AECA and CFBF specifying a date when the data will be provided. Notice of the availability of tracking data will be provided to CLECA and to EPUC. The notice will identify what data is being provided by reference to the alpha and numerical designations in the *AG Data Reporting Requirements.* Tracking data will be provided for the years 2016 through 2019.

Part A, Question 4: 2017 Generation Recorded Data

4. Recorded Data during the Tracking Period
a) Monthly bundled sales and DA/CCA sales for each rate schedule
b) Hourly bundled sales for each agricultural rate schedule, where available
c) Hourly DA/CCA sales for each agricultural rate schedule, where available
d) Hourly PG&E system-total bundled sales, where available
e) Hourly PG&E total DA/CCA sales, where available
f) DA/CCA PCIA revenue from each agricultural rate schedule
g) Total PCIA revenue
h) Bundled generation revenue from each agricultural rate schedule
i) Total bundled generation revenue
j) Summer and winter generation PCAFs for each rate schedule
k) Bundled agricultural demand from each rate schedule, as available based on billing data:
    i) Maximum demand summer
    ii) Maximum demand winter
    iii) Maximum peak demand summer
    iv) Maximum part-peak demand summer
    v) Maximum part-peak demand winter

Part B, Question 4, 2017 Distribution Recorded Data

4. Recorded data during the Tracking Period:

a) Number of meters (averaged over period) for each agricultural rate schedule
b) Number of new connects for each agricultural rate schedule
c) Number of disconnects for each agricultural rate schedule
d) Summer and winter distribution PCAFs for each rate schedule
e) Distribution FLTs for each rate schedule
f) Distribution agricultural demand from each rate schedule, as available based on billing data:
    i) Maximum demand summer
    ii) Maximum demand winter
    iii) Maximum peak demand summer
    iv) Maximum part-peak demand summer
    v) Maximum part-peak demand winter
g) Distribution revenue from each agricultural rate schedule
h) System-total distribution revenue
i) NSGC revenue from each agricultural rate schedule
j) System-total NSGC revenue

Confidentiality

1) Customer specific information shall be anonymized and aggregated to meet the Commission's aggregation requirements in D.14-05-016, at a minimum. Where the aggregation standards cannot be met, the customer information will be anonymized, and access to the anonymized information will be treated as confidential and provided pursuant to the 2017 GRC II NDA to the party and its consultants who have executed the non-disclosure agreement for the 2017 GRC II case. If it is still possible to identify the customer given the anonymized information, the customer information will not be provided to anyone except Commission staff.
2) PG&E may designate other confidential information as subject to the non-disclosure agreement, and the information will only be provided to the party and its consultants who have executed the non-disclosure agreement for the 2017 GRC II case, and as consistent with the terms of that NDA. Any information provided under this agreement that PG&E designates as subject to the NDA will be clearly marked with this designation.
3) With respect to confidential data provided under the *AG Data Reporting Requirements*, PG&E will not send the notice provided under Section 5 of the 2017 GRC II NDA before issues for which the data is used in PG&E's next GRC II case are resolved there.
4) Submission or use of confidential data that was received pursuant to this agreement for PG&E's next GRC II case will require appropriate confidentiality protections in that case, including NDAs and/or motions for confidential treatment in that docket. Examples would be testimony, work papers, data responses, reports, etc., that include confidential information.

Answer Part A, Question 4. Generation Tracking. Each tab of the attached file GRC-2017-PhII_DR_AGParties_DataRep_2017_A-Q04_B-Q04-Atch01 is labeled with the associated subpart. Hourly sales for each agricultural schedule and for the system are provided where available. Hourly data was summed from interval data. Sales that were not available on an interval basis are also provided. Generation PCAFs developed for this response were based on the methods used in the past for generating PCAF values. PG&E may revise its method in its upcoming 2020 GRC Phase II proceeding. This information is not confidential.

Answer Part B, Question 4. Distribution Tracking. Each tab of the attached file GRC-2017-PhII_DR_AGParties_DataRep_2017_A-Q04_B-Q04-Atch02 is labeled with the associated subpart. All subparts to this question except subpart e are included. Information in Attachment 2 is not confidential. Distribution PCAFs developed for this response were based on the methods used in the past for generating PCAF values and are provided before application of loss factors. PG&E has provided loss factors from the prior GRC for reference. PG&E may revise its method in its upcoming 2020 GRC Phase II proceeding. With regard to subparts b and c, a determination of connections was based on the first service at a premise, and disconnections were determined based on the date the last service at a premise ended. PG&E's estimate of new connections for purposes of developing marginal cost in the 2020 GRC Phase II may vary from the values presented herein.

Answer Part B, Question 4, subpart e. **This response contains confidential customer information provided pursuant to the NDA in A. 16-06-013.** Information provided in response to this request is in GRC-2017-PhII_DR_AGParties_DataRep_2017_A-Q04_B-Q04-Atch03CONF. Annual non-coincident demand by schedule is provided in response to this request. For reference, PG&E has also provided residential and small commercial diversity factors from the last GRC which were used to develop FLT loads. Non-coincident demand and diversity factors provided in this response were based on the methods used in the past for generating FLT values. PG&E may revise its method in its upcoming 2020 GRC Phase II proceeding.

PACIFIC GAS AND ELECTRIC COMPANY
2017 General Rate Case Phase II
Compliance Requirement

PG&E Data Request No.:	AG Parties_DataRep_2017-A-Q04j-SUPP01		
PG&E File Name:	GRC-2017-PhII_DR_AGParties_DataRep_2017-A-Q04j-SUPP01		
Request Date:	May 13, 2019	Requester DR No.:	Ag Data Reporting Requirements
Date Sent:	August 1, 2019	Requesting Party:	AECA and CFBF
PG&E Witness:	Keith Coyne	Requester:	Richard McCann

Part A, Question 4j: 2017 Generation Recorded Data

4. Recorded Data during the Tracking Period
j) Summer and winter generation PCAFs for each rate schedule

Follow-up Question to Part A, 4j:

The generation PCAF data for 2017 was far out of line with data for previous years as can be seen in the graphs below. The difference isn't easily explained and it runs across all of the rate classes.

ANSWER - SUPP01

Answer Part A, 2017, Question 4j, Supplemental 01 (SUPP01)

On April 1, 2019, PG&E provided a data response containing 2017 Generation PCAF data for Part A, Question 4j, for 2017, in the text response and associated attachment for 2017-PhII_DR_AGParties_DataRep_2017_A-Q04_B-Q04-Atch01.

Subsequently, on May 13, 2019, Dr. Richard McCann, consultant for AECA, sent the above follow-up question to PG&E. Dr. McCann is correct that the Generation PCAF data PG&E previously provided for 2017 was incorrect. PG&E has now corrected the 2017 Generation PCAF data, as provided in the attached non-confidential file "2017-PhII_DR_AGParties_DataRep_2017_A-Q04j-SUPP01.xls."

PACIFIC GAS AND ELECTRIC COMPANY
2017 General Rate Case Phase II
Compliance Requirement

PG&E Data Request No.:	AG Parties_DataRep_Compliance-2018_PartA/B_A-Q01_B-Q01		
PG&E File Name:	GRC-2017-PhII_DR_AGParties_DataRep_2018-A-Q01_B-Q01		
Request Date:	August 9, 2018, D.18-08-013	Requester DR No.: MC/RA Settlement	Ag Data Reporting Requirements
Date Sent:	April 19, 2019	Requesting Party:	AECA and CFBF
PG&E Witness:	Keith Coyne	Requester:	

Tracking data specified in Sections A and B will be reported to AECA and CFBF annually in a spreadsheet format, lagged by at least 90 days, or as the data become available. If data will not be available within the 90-day target, notification will be sent to AECA and CFBF specifying a date when the data will be provided. Notice of the availability of tracking data will be provided to CLECA and to EPUC. The notice will identify what data is being provided by reference to the alpha and numerical designations in the *AG Data Reporting Requirements.* Tracking data will be provided for the years 2016 through 2019.

Part A Question 1: 2018 Generation Data Tracking

1) Forecast Data from Advice Letters[1]
   a) Forecasts of bundled sales and DA/CCA sales for each agricultural rate schedule (excluding E-37 customers) from the Annual Electric True Up Advice Letter (AET)
   b) Forecasts of system total bundled sales and DA/CCA sales from the AET
   c) Forecasts of generation revenue and Power Charge Indifference Adjustment (PCIA) revenue[2] from each agricultural rate schedule (excluding E-37 customers) from the AET and any other advice letters that modify the generation or PCIA rate
   d) Forecasts of total generation revenue and PCIA revenue from the AET and any other advice letters that modify the generation or PCIA rate
   e) Average generation rates and PCIA rates for each agricultural rate schedule (excluding E-37 customers) from the AET and any other advice letters that modify the generation or PCIA rate
   f) System-average generation rate and PCIA rate from the AET and any other advice letters that modify the PCIA rate

[1] For agricultural class data, advice letter data will be adjusted to remove Schedule E-37 from the agricultural class.
[2] References to the PCIA incorporate any PCIA successor charge that may be adopted.

Part B Question 1: 2018 Distribution Tracking

1) Forecast Data from Advice Letters[3]
   a) Average distribution rate for each agricultural rate schedule (excluding E-37) from the AET and any other advice letters that modify the distribution rate
   b) Distribution revenue from each agricultural rate schedule (excluding E-37) from the AET and any other advice letters that modify the distribution rate
   c) System-average distribution rate from the AET and any other advice letters that modify the distribution rate
   d) System total distribution revenue from the AET and any other advice letters that modify the distribution rate
   e) Average New System Generation Charge (NSGC) rate for each agricultural rate schedule (excluding E-37) from the AET and any other advice letters that modify the NSGC rate
   f) Total NSGC revenue from each agricultural rate schedule (excluding E-37) from the AET and any other advice letters that modify the NSGC rate
   g) System-average NSGC rate from the AET and any other advice letters that modify the NSGC rate
   h) System total NSGC revenue from the AET and any other advice letters that modify the NSGC rate

Confidentiality: Responses to Part A, Question 1 and Part B, Question 1 are not confidential.

Answer to Part A, Question 1 and Part B, Question 1.

Responses for 2018 are contained in the attached file GRC-2017-PhII_DR_AGParties_DataRep2018-A-Q01_B-Q01Atch01. Please note that beginning March 1, 2018, Schedule E-37 was no longer combined with agricultural sales.

[3] For agricultural class data, advice letter data will be adjusted to remove Schedule E-37 from the agricultural class.

PACIFIC GAS AND ELECTRIC COMPANY
2017 General Rate Case Phase II
Compliance Requirement

PG&E Data Request No.:	AG Parties_DataRep_Compliance-2018_PartA/B_A-Q04_B-Q04		
PG&E File Name:	GRC-2017-PhII_DR_AGParties_DataRep_2018_A-Q04_B-Q04		
Request Date:	August 9, 2018, D.18-08-013	Requester DR No.: MC/RA Settlement	Ag Data Reporting Requirements
Date Sent:	April 19, 2019	Requesting Party:	AECA and CFBF
PG&E Witness:	Keith Coyne	Requester:	

Tracking data specified in Sections A and B will be reported to AECA and CFBF annually in a spreadsheet format, lagged by at least 90 days, or as the data become available. If data will not be available within the 90-day target, notification will be sent to AECA and CFBF specifying a date when the data will be provided. Notice of the availability of tracking data will be provided to CLECA and to EPUC. The notice will identify what data is being provided by reference to the alpha and numerical designations in the *AG Data Reporting Requirements.* Tracking data will be provided for the years 2016 through 2019.

Part A, Question 4: 2018 Generation Recorded Data

4. Recorded Data during the Tracking Period
a) Monthly bundled sales and DA/CCA sales for each rate schedule
b) Hourly bundled sales for each agricultural rate schedule, where available
c) Hourly DA/CCA sales for each agricultural rate schedule, where available
d) Hourly PG&E system-total bundled sales, where available
e) Hourly PG&E total DA/CCA sales, where available
f) DA/CCA PCIA revenue from each agricultural rate schedule
g) Total PCIA revenue
h) Bundled generation revenue from each agricultural rate schedule
i) Total bundled generation revenue
j) Summer and winter generation PCAFs for each rate schedule
k) Bundled agricultural demand from each rate schedule, as available based on billing data:
    i) Maximum demand summer
    ii) Maximum demand winter
    iii) Maximum peak demand summer
    iv) Maximum part-peak demand summer
    v) Maximum part-peak demand winter

Part B, Question 4, 2018 Distribution Recorded Data

4. Recorded data during the Tracking Period:
   a) Number of meters (averaged over period) for each agricultural rate schedule
   b) Number of new connects for each agricultural rate schedule
   c) Number of disconnects for each agricultural rate schedule
   d) Summer and winter distribution PCAFs for each rate schedule
   e) Distribution FLTs for each rate schedule
   f) Distribution agricultural demand from each rate schedule, as available based on billing data:
      i) Maximum demand summer
      ii) Maximum demand winter
      iii) Maximum peak demand summer
      iv) Maximum part-peak demand summer
      v) Maximum part-peak demand winter
   g) Distribution revenue from each agricultural rate schedule
   h) System-total distribution revenue
   i) NSGC revenue from each agricultural rate schedule
   j) System-total NSGC revenue

Confidentiality

1) Customer specific information shall be anonymized and aggregated to meet the Commission's aggregation requirements in D.14-05-016, at a minimum. Where the aggregation standards cannot be met, the customer information will be anonymized, and access to the anonymized information will be treated as confidential and provided pursuant to the 2017 GRC II NDA to the party and its consultants who have executed the non-disclosure agreement for the 2017 GRC II case. If it is still possible to identify the customer given the anonymized information, the customer information will not be provided to anyone except Commission staff.
2) PG&E may designate other confidential information as subject to the non-disclosure agreement, and the information will only be provided to the party and its consultants who have executed the non-disclosure agreement for the 2017 GRC II case, and as consistent with the terms of that NDA. Any information provided under this agreement that PG&E designates as subject to the NDA will be clearly marked with this designation.
3) With respect to confidential data provided under the *AG Data Reporting Requirements*, PG&E will not send the notice provided under Section 5 of the 2017 GRC II NDA before issues for which the data is used in PG&E's next GRC II case are resolved there.
4) Submission or use of confidential data that was received pursuant to this agreement for PG&E's next GRC II case will require appropriate confidentiality protections in that case, including NDAs and/or motions for confidential treatment in that docket. Examples would be testimony, work papers, data responses, reports, etc., that include confidential information.

Answer Part A, Question 4. Generation Tracking. Each tab of the attached file GRC-2017-PhII_DR_AGParties_DataRep_2018_A-Q04_B-Q04-Atch01 is labeled with the

associated subpart. Hourly sales for each agricultural schedule and for the system are provided where available. Hourly data was summed from interval data. Sales that were not available on an interval basis are also provided. Generation PCAFs for this response are not yet available, but will be based on the methods used in the past for generating PCAF values. PG&E may revise its method in its upcoming 2020 GRC Phase II proceeding. This information is not confidential.

Please note as stated above that in Atch01, Part A, Question 4, subpart j, tab j in the Atch01 spreadsheet, data for summer and winter generation PCAFs for each rate schedule, is not currently available. PG&E plans to send this data by August 1, 2019. This information is developed as part of PG&E's class load research work and will not be available until that time frame.

Answer Part B, Question 4. Distribution Tracking. Each tab of the attached file GRC-2017-PhII_DR_AGParties_DataRep_2018_A-Q04_B-Q04-Atch02 is labeled with the associated subpart. All subparts to this question except subpart e are included. Information in Attachment 2 is not confidential. Distribution PCAFs for this response are not yet available, but will be based on the methods used in the past for generating PCAF values and are provided before application of loss factors. PG&E will provide loss factors from the prior GRC for reference. PG&E may revise its method in its upcoming 2020 GRC Phase II proceeding. With regard to subparts b and c, a determination of connections was based on the first service at a premise, and disconnections were determined based on the date the last service at a premise ended. PG&E's estimate of new connections for purposes of developing marginal cost in the 2020 GRC Phase II may vary from the values presented herein.

Please note as stated above that in Atch02, Part B, Question 4, subpart d, tab d in the Atch02 spreadsheet, data for summer and winter distribution PCAFs for each rate schedule, is not currently available. PG&E plans to send this data by August 1, 2019. This information is developed as part of PG&E's class load research work and will not be available until that time frame.

Answer Part B, Question 4, subpart e. **This response will contain confidential customer information provided pursuant to the NDA in A. 16-06-013.** Information provided in response to this question will be in GRC-2017-PhII_DR_AGParties_DataRep_2018_A-Q04_B-Q04-Atch03CONF, but is not currently available. Annual non-coincident demand by schedule will be provided in response to this request. For reference, PG&E will also provide residential and small commercial diversity factors from the last GRC which were used to develop FLT loads. Non coincident demand and diversity factors provided in response to this question will be based on the methods used in the past for generating FLT values. PG&E may revise its method in its upcoming 2020 GRC Phase II proceeding.

Please note as stated above that Atch03, Part B, Question 4, subpart e, confidential data and Atch03, data for distribution FLTs for each rate schedule, is not currently available. PG&E plans to send this data by August 1, 2019. This information is developed as part of PG&E's class load research work and will not be available until that time frame.

PACIFIC GAS AND ELECTRIC COMPANY
2017 General Rate Case Phase II
Compliance Requirement

PG&E Data Request No.:	AG Parties_DataRep_Compliance-2018_PartA/B_A-Q04_B-Q04		
PG&E File Name:	GRC-2017-PhII_DR_AGParties_DataRep_2018_A-Q04j_B-Q04de-SUPP01		
Request Date:	August 9, 2018, D.18-08-013	Requester DR No.: MC/RA Settlement	Ag Data Reporting Requirements
Date Sent:	August 1, 2019	Requesting Party:	AECA and CFBF
PG&E Witness:	Keith Coyne	Requester:	

Tracking data specified in Sections A and B will be reported to AECA and CFBF annually in a spreadsheet format, lagged by at least 90 days, or as the data become available. If data will not be available within the 90-day target, notification will be sent to AECA and CFBF specifying a date when the data will be provided. Notice of the availability of tracking data will be provided to CLECA and to EPUC. The notice will identify what data is being provided by reference to the alpha and numerical designations in the *AG Data Reporting Requirements.* Tracking data will be provided for the years 2016 through 2019.

Part A, Question 4: 2018 Generation Recorded Data

4. Recorded Data during the Tracking Period
a) Monthly bundled sales and DA/CCA sales for each rate schedule
b) Hourly bundled sales for each agricultural rate schedule, where available
c) Hourly DA/CCA sales for each agricultural rate schedule, where available
d) Hourly PG&E system-total bundled sales, where available
e) Hourly PG&E total DA/CCA sales, where available
f) DA/CCA PCIA revenue from each agricultural rate schedule
g) Total PCIA revenue
h) Bundled generation revenue from each agricultural rate schedule
i) Total bundled generation revenue
j) Summer and winter generation PCAFs for each rate schedule
k) Bundled agricultural demand from each rate schedule, as available based on billing data:
    i) Maximum demand summer
    ii) Maximum demand winter
    iii) Maximum peak demand summer
    iv) Maximum part-peak demand summer
    v) Maximum part-peak demand winter

Part B, Question 4, 2018 Distribution Recorded Data

4. Recorded data during the Tracking Period:

a) Number of meters (averaged over period) for each agricultural rate schedule
b) Number of new connects for each agricultural rate schedule
c) Number of disconnects for each agricultural rate schedule
d) Summer and winter distribution PCAFs for each rate schedule
e) Distribution FLTs for each rate schedule
f) Distribution agricultural demand from each rate schedule, as available based on billing data:
    i) Maximum demand summer
    ii) Maximum demand winter
    iii) Maximum peak demand summer
    iv) Maximum part-peak demand summer
    v) Maximum part-peak demand winter
g) Distribution revenue from each agricultural rate schedule
h) System-total distribution revenue
i) NSGC revenue from each agricultural rate schedule
j) System-total NSGC revenue

Confidentiality

1) Customer specific information shall be anonymized and aggregated to meet the Commission's aggregation requirements in D.14-05-016, at a minimum. Where the aggregation standards cannot be met, the customer information will be anonymized, and access to the anonymized information will be treated as confidential and provided pursuant to the 2017 GRC II NDA to the party and its consultants who have executed the non-disclosure agreement for the 2017 GRC II case. If it is still possible to identify the customer given the anonymized information, the customer information will not be provided to anyone except Commission staff.
2) PG&E may designate other confidential information as subject to the non-disclosure agreement, and the information will only be provided to the party and its consultants who have executed the non-disclosure agreement for the 2017 GRC II case, and as consistent with the terms of that NDA. Any information provided under this agreement that PG&E designates as subject to the NDA will be clearly marked with this designation.
3) With respect to confidential data provided under the *AG Data Reporting Requirements*, PG&E will not send the notice provided under Section 5 of the 2017 GRC II NDA before issues for which the data is used in PG&E's next GRC II case are resolved there.
4) Submission or use of confidential data that was received pursuant to this agreement for PG&E's next GRC II case will require appropriate confidentiality protections in that case, including NDAs and/or motions for confidential treatment in that docket. Examples would be testimony, work papers, data responses, reports, etc., that

include confidential information.

Answer

In the data response for "GRC-2017-PhII_DR_AGParties_DataRep_2018_A-Q04_B-Q04" provided by PG&E on April 19, 2019, the following three items were not provided because each relies on class load research analysis of a given calendar year that is generally not completed until approximately 8 months after the calendar year has ended:

- Part A, Q4j = Generation PCAF's for 2018 using past methods,
- Part B, Q4d = Distribution PCAF's for 2018 using past methods,
- Part B, Q4e = Distribution FLT's for 2018 using past methods.

In this SUPP01 data response, PG&E now provides these three items below. PG&E has labeled this SUPP01 data response as follows:

"GRC-2017-PhII_DR_AGParties_DataRep_2018_A-Q04j_B-Q04de-SUPP01.pdf"

Answer Part A, Question 4j. Generation Tracking. The attached file GRC-2017-PhII_DR_AGParties_DataRep_2018_A-Q04j_SUPP01-Atch01 is labeled with the associated 4j subpart. Hourly sales for each agricultural schedule and for the system are provided where available. Hourly data was summed from interval data. Sales that were not available on an interval basis are also provided. Generation PCAFs developed for this response were based on the methods used in the past for generating PCAF values. PG&E may revise its method for Generation PCAF's in its upcoming 2020 GRC Phase II proceeding. This information is not confidential.

Answer Part B, Question 4, subpart d. Distribution Tracking. The attached file GRC-2017-PhII_DR_AGParties_DataRep_2018_B-Q04d_SUPP01-Atch02 is labeled with the associated subpart. Information in Attachment 2 is not confidential. Distribution PCAFs developed for this response were based on the methods used in the past for generating PCAF values and are provided before application of loss factors. PG&E has provided loss factors from the prior GRC for reference. PG&E may revise its method for Distribution PCAF's in its upcoming 2020 GRC Phase II proceeding.

Answer Part B, Question 4, subpart e. Distribution Tracking. **This response contains confidential customer information provided pursuant to the NDA in A.16-06-013.** Information provided in response to this question is in GRC-2017-PhII_DR_AGParties_DataRep_2018_B-Q04e_SUPP01-Atch03CONF. Annual non-coincident demand by schedule is provided in response to this request. For reference, PG&E has also provided residential and small commercial diversity factors from the last GRC which were used to develop FLT loads. Non coincident demand and diversity factors provided in response to this question were based on the methods used in the past

for generating FLT values. PG&E may revise its method for Distribution FLT loads in its upcoming 2020 GRC Phase II proceeding.

PACIFIC GAS AND ELECTRIC COMPANY
2017 General Rate Case Phase II Compliance Requirement

PG&E Data Request No.:	AG Parties_DataRep_Compliance-2018_PartA/B_A-Q01_B-Q01		
PG&E File Name:	GRC-2017-PhII_DR_AGParties_DataRep_2018-A-Q01_B-Q01		
Request Date:	August 9, 2018, D.18-08-013	Requester DR No.: MC/RA Settlement	Ag Data Reporting Requirements
Date Sent:	March 30, 2020	Requesting Party:	AECA and CFBF
PG&E Witness:	Keith Coyne	Requester:	

Tracking data specified in Sections A and B will be reported to AECA and CFBF annually in a spreadsheet format, lagged by at least 90 days, or as the data become available. If data will not be available within the 90-day target, notification will be sent to AECA and CFBF specifying a date when the data will be provided. Notice of the availability of tracking data will be provided to CLECA and to EPUC. The notice will identify what data is being provided by reference to the alpha and numerical designations in the *AG Data Reporting Requirements.* Tracking data will be provided for the years 2016 through 2019.

Part A Question 1: 2019 Generation Data Tracking

1) Forecast Data from Advice Letters[1]
   a) Forecasts of bundled sales and DA/CCA sales for each agricultural rate schedule (excluding E-37 customers) from the Annual Electric True Up Advice Letter (AET)
   b) Forecasts of system total bundled sales and DA/CCA sales from the AET
   c) Forecasts of generation revenue and Power Charge Indifference Adjustment (PCIA) revenue[2] from each agricultural rate schedule (excluding E-37 customers) from the AET and any other advice letters that modify the generation or PCIA rate
   d) Forecasts of total generation revenue and PCIA revenue from the AET and any other advice letters that modify the generation or PCIA rate
   e) Average generation rates and PCIA rates for each agricultural rate schedule (excluding E-37 customers) from the AET and any other advice letters that modify the generation or PCIA rate
   f) System-average generation rate and PCIA rate from the AET and any other advice letters that modify the PCIA rate

Part B Question 1: 2019 Distribution Tracking

1) Forecast Data from Advice Letters[2]

[1] For agricultural class data, advice letter data will be adjusted to remove Schedule E-37 from the agricultural class. [2] References to the PCIA incorporate any PCIA successor charge that may be adopted.
[2] For agricultural class data, advice letter data will be adjusted to remove Schedule E-37 from the agricultural class.

a) Average distribution rate for each agricultural rate schedule (excluding E-37) from the AET and any other advice letters that modify the distribution rate
b) Distribution revenue from each agricultural rate schedule (excluding E-37) from the AET and any other advice letters that modify the distribution rate
c) System-average distribution rate from the AET and any other advice letters that modify the distribution rate
d) System total distribution revenue from the AET and any other advice letters that modify the distribution rate
e) Average New System Generation Charge (NSGC) rate for each agricultural rate schedule (excluding E-37) from the AET and any other advice letters that modify the NSGC rate
f) Total NSGC revenue from each agricultural rate schedule (excluding E-37) from the AET and any other advice letters that modify the NSGC rate
g) System-average NSGC rate from the AET and any other advice letters that modify the NSGC rate
h) System total NSGC revenue from the AET and any other advice letters that modify the NSGC rate

Confidentiality: Responses to Part A, Question 1 and Part B, Question 1 are not confidential.

Answer to Part A, Question 1 and Part B, Question 1.

Responses for 2019 are contained in the attached file GRC-2017-PhII_DR_AGParties_DataRep2019-A-Q01_B-Q01Atch01. Please note that beginning March 1, 2018, Schedule E-37 was no longer combined with agricultural sales. In addition, forecast 2018 sales were used in all electric rate design changes until the 2019 sales forecast was implemented in electric rates, effective July 1, 2019.

PACIFIC GAS AND ELECTRIC COMPANY
2017 General Rate Case Phase II
Compliance Requirement

PG&E Data Request No.:	AG Parties_DataRep_Compliance-2019_PartA/B_A-Q04_B-Q04		
PG&E File Name:	GRC-2017-PhII_DR_AGParties_DataRep_2019_A-Q04_B-Q04		
Request Date:	August 9, 2018, D.18-08-013	Requester DR No.: MC/RA Settlement	Ag Data Reporting Requirements
Date Sent:	March 30, 2020	Requesting Party:	AECA and CFBF
PG&E Witness:	Keith Coyne	Requester:	

Tracking data specified in Sections A and B will be reported to AECA and CFBF annually in a spreadsheet format, lagged by at least 90 days, or as the data become available. If data will not be available within the 90-day target, notification will be sent to AECA and CFBF specifying a date when the data will be provided. Notice of the availability of tracking data will be provided to CLECA and to EPUC. The notice will identify what data is being provided by reference to the alpha and numerical designations in the *AG Data Reporting Requirements.* Tracking data will be provided for the years 2016 through 2019.

Part A, Question 4: 2019 Generation Recorded Data

4. Recorded Data during the Tracking Period
a) Monthly bundled sales and DA/CCA sales for each rate schedule
b) Hourly bundled sales for each agricultural rate schedule, where available
c) Hourly DA/CCA sales for each agricultural rate schedule, where available
d) Hourly PG&E system-total bundled sales, where available
e) Hourly PG&E total DA/CCA sales, where available
f) DA/CCA PCIA revenue from each agricultural rate schedule
g) Total PCIA revenue
h) Bundled generation revenue from each agricultural rate schedule
i) Total bundled generation revenue
j) Summer and winter generation PCAFs for each rate schedule
k) Bundled agricultural demand from each rate schedule, as available based on billing data:
    i) Maximum demand summer
    ii) Maximum demand winter
    iii) Maximum peak demand summer
    iv) Maximum part-peak demand summer
    v) Maximum part-peak demand winter

Part B, Question 4, 2019 Distribution Recorded Data

4. Recorded data during the Tracking Period:

a) Number of meters (averaged over period) for each agricultural rate schedule
b) Number of new connects for each agricultural rate schedule
c) Number of disconnects for each agricultural rate schedule
d) Summer and winter distribution PCAFs for each rate schedule
e) Distribution FLTs for each rate schedule
f) Distribution agricultural demand from each rate schedule, as available based on billing data:
    i) Maximum demand summer
    ii) Maximum demand winter
    iii) Maximum peak demand summer
    iv) Maximum part-peak demand summer
    v) Maximum part-peak demand winter
g) Distribution revenue from each agricultural rate schedule
h) System-total distribution revenue
i) NSGC revenue from each agricultural rate schedule
j) System-total NSGC revenue

Confidentiality

1) Customer specific information shall be anonymized and aggregated to meet the Commission's aggregation requirements in D.14-05-016, at a minimum. Where the aggregation standards cannot be met, the customer information will be anonymized, and access to the anonymized information will be treated as confidential and provided pursuant to the 2017 GRC II NDA to the party and its consultants who have executed the non-disclosure agreement for the 2017 GRC II case. If it is still possible to identify the customer given the anonymized information, the customer information will not be provided to anyone except Commission staff.
2) PG&E may designate other confidential information as subject to the non-disclosure agreement, and the information will only be provided to the party and its consultants who have executed the non-disclosure agreement for the 2017 GRC II case, and as consistent with the terms of that NDA. Any information provided under this agreement that PG&E designates as subject to the NDA will be clearly marked with this designation.
3) With respect to confidential data provided under the *AG Data Reporting Requirements*, PG&E will not send the notice provided under Section 5 of the 2017 GRC II NDA before issues for which the data is used in PG&E's next GRC II case are resolved there.
4) Submission or use of confidential data that was received pursuant to this agreement for PG&E's next GRC II case will require appropriate confidentiality protections in that case, including NDAs and/or motions for confidential treatment in that docket. Examples would be testimony, work papers, data responses, reports, etc., that include confidential information.

Answer Part A, Question 4. Generation Tracking. Each tab of the attached file GRC-2017-PhII_DR_AGParties_DataRep_2019_A-Q04_B-Q04-Atch01 is labeled with the associated subpart. Hourly sales for each agricultural schedule and for the system are provided where available. Hourly data was summed from interval data. Sales that were not available on an interval basis are also provided. Generation PCAFs for this response are not yet available but will be based on the methods used in the past for generating PCAF values. PG&E may revise its method in its upcoming 2020 GRC Phase II proceeding. This information is not confidential.

Please note as stated above that in Atch01, Part A, Question 4, subpart j, tab j in the Atch01 spreadsheet, data for summer and winter generation PCAFs for each rate schedule, is not currently available. PG&E plans to send this data by August 1, 2020. This information is developed as part of PG&E's class load research work and will not be available until that time frame.

Answer Part B, Question 4. Distribution Tracking. Each tab of the attached file GRC-2017-PhII_DR_AGParties_DataRep_2019_A-Q04_B-Q04-Atch02 is labeled with the associated subpart. All subparts to this question except subparts d are included. Information in Attachment 2 is not confidential. Distribution PCAFs for this response are not yet available but will be based on the methods used in the past for generating PCAF values and are provided before application of loss factors. PG&E will provide loss factors from the prior GRC for reference. PG&E may revise its method in its upcoming 2020 GRC Phase II proceeding. With regard to subparts b and c, a determination of connections was based on the first service at a premise, and disconnections were determined based on the date the last service at a premise ended. PG&E's estimate of new connections for purposes of developing marginal cost in the 2020 GRC Phase II may vary from the values presented herein.

Please note as stated above that in Atch02, Part B, Question 4, subpart d, tab d in the Atch02 spreadsheet, data for summer and winter distribution PCAFs for each rate schedule, is not currently available. PG&E plans to send this data by August 1, 2020. This information is developed as part of PG&E's class load research work and will not be available until that time frame.

Answer Part B, Question 4, subpart e. **This response will contain confidential customer information provided pursuant to the NDA in A. 16-06-013.** Information provided in response to this question will be in GRC-2017-PhII_DR_AGParties_DataRep_2019_A-Q04_B-Q04-Atch03CONF but is not currently available. Annual non-coincident demand by schedule will be provided in response to this request. For reference, PG&E will also provide residential and small commercial diversity factors from the last GRC which were used to develop FLT loads. Non coincident demand and diversity factors provided in response to this question will be based on the methods used in the past for generating FLT values. PG&E may revise its method in its upcoming 2020 GRC Phase II proceeding.

Please note as stated above that Atch03, Part B, Question 4, subpart e, confidential data for distribution FLTs for each rate schedule, is not currently available. PG&E plans to send this data by August 1, 2020. This information is developed as part of PG&E's class load research work and will not be available until that time frame.

PACIFIC GAS AND ELECTRIC COMPANY
2017 General Rate Case Phase II
Compliance Requirement

PG&E Data Request No.:	AG Parties_DataRep_Compliance-2019_PartA/B_A-Q04_B-Q04		
PG&E File Name:	GRC-2017-PhII_DR_AGParties_DataRep_2019_A-Q04j_B-Q04de-SUPP01		
Request Date:	August 9, 2018, D.18-08-013	Requester DR No.: MC/RA Settlement	Ag Data Reporting Requirements
Date Sent:	July 31, 2020	Requesting Party:	AECA and CFBF
PG&E Witness:	Keith Coyne	Requester:	

Tracking data specified in Sections A and B will be reported to AECA and CFBF annually in a spreadsheet format, lagged by at least 90 days, or as the data become available. If data will not be available within the 90-day target, notification will be sent to AECA and CFBF specifying a date when the data will be provided. Notice of the availability of tracking data will be provided to CLECA and to EPUC. The notice will identify what data is being provided by reference to the alpha and numerical designations in the *AG Data Reporting Requirements.* Tracking data will be provided for the years 2016 through 2019.

Part A, Question 4: 2019 Generation Recorded Data

4. Recorded Data during the Tracking Period

a) Monthly bundled sales and DA/CCA sales for each rate schedule
b) Hourly bundled sales for each agricultural rate schedule, where available
c) Hourly DA/CCA sales for each agricultural rate schedule, where available
d) Hourly PG&E system-total bundled sales, where available
e) Hourly PG&E total DA/CCA sales, where available
f) DA/CCA PCIA revenue from each agricultural rate schedule
g) Total PCIA revenue
h) Bundled generation revenue from each agricultural rate schedule
i) Total bundled generation revenue
j) Summer and winter generation PCAFs for each rate schedule
k) Bundled agricultural demand from each rate schedule, as available based on billing data:
    i) Maximum demand summer
    ii) Maximum demand winter
    iii) Maximum peak demand summer
    iv) Maximum part-peak demand summer
    v) Maximum part-peak demand winter

Part B, Question 4, 2019 Distribution Recorded Data

4. Recorded data during the Tracking Period:

a) Number of meters (averaged over period) for each agricultural rate schedule
b) Number of new connects for each agricultural rate schedule
c) Number of disconnects for each agricultural rate schedule
d) Summer and winter distribution PCAFs for each rate schedule
e) Distribution FLTs for each rate schedule
f) Distribution agricultural demand from each rate schedule, as available based on billing data:
    i) Maximum demand summer
    ii) Maximum demand winter
    iii) Maximum peak demand summer
    iv) Maximum part-peak demand summer
    v) Maximum part-peak demand winter
g) Distribution revenue from each agricultural rate schedule
h) System-total distribution revenue
i) NSGC revenue from each agricultural rate schedule
j) System-total NSGC revenue

Confidentiality

1) Customer specific information shall be anonymized and aggregated to meet the Commission's aggregation requirements in D.14-05-016, at a minimum. Where the aggregation standards cannot be met, the customer information will be anonymized, and access to the anonymized information will be treated as confidential and provided pursuant to the 2017 GRC II NDA to the party and its consultants who have executed the non-disclosure agreement for the 2017 GRC II case. If it is still possible to identify the customer given the anonymized information, the customer information will not be provided to anyone except Commission staff.
2) PG&E may designate other confidential information as subject to the non-disclosure agreement, and the information will only be provided to the party and its consultants who have executed the non-disclosure agreement for the 2017 GRC II case, and as consistent with the terms of that NDA. Any information provided under this agreement that PG&E designates as subject to the NDA will be clearly marked with this designation.
3) With respect to confidential data provided under the *AG Data Reporting Requirements*, PG&E will not send the notice provided under Section 5 of the 2017 GRC II NDA before issues for which the data is used in PG&E's next GRC II case are resolved there.
4) Submission or use of confidential data that was received pursuant to this agreement for PG&E's next GRC II case will require appropriate confidentiality protections in that case, including NDAs and/or motions for confidential treatment in that docket. Examples would be testimony, work papers, data responses, reports, etc., that include confidential information.

Answer

In the data response for "GRC-2017-PhII_DR_AGParties_DataRep_2019_A-Q04_B-Q04" provided by PG&E on March 30, 2020, the following three items were not provided because each relies on class load research analysis of a given calendar year that is generally not completed until approximately 8 months after the calendar year has ended:

- Part A, Q4j = Generation PCAF's for 2019 using past methods,
- Part B, Q4d = Distribution PCAF's for 2019 using past methods,
- Part B, Q4e = Distribution FLT's for 2019 using past methods.

In this SUPP01 data response, PG&E now provides these three items below. PG&E has labeled this SUPP01 data response as follows:

"GRC-2017-PhII_DR_AGParties_DataRep_2019_A-Q04j_B-Q04de-SUPP01.pdf"

Answer Part A, Question 4j. Generation Tracking. The attached file GRC-2017-PhII_DR_AGParties_DataRep_2019_A-Q04j_SUPP01-Atch01 is labeled with the associated 4j subpart. Hourly sales for each agricultural schedule and for the system are provided where available. Hourly data was summed from interval data. Sales that were not available on an interval basis are also provided. Generation PCAFs developed for this response were based on the methods used in the past for generating PCAF values. PG&E revised its method for Generation PCAF's in its 2020 GRC Phase II proceeding. This information is not confidential.

Answer Part B, Question 4, subpart d. Distribution Tracking. The attached file GRC-2017-PhII_DR_AGParties_DataRep_2019_B-Q04d_SUPP01-Atch02 is labeled with the associated subpart. Information in Attachment 2 is not confidential. Distribution PCAFs developed for this response were based on the methods used in the past for generating PCAF values and are provided before application of loss factors. PG&E has provided loss factors from the prior GRC for reference. PG&E revised its method for Distribution PCAF's in its 2020 GRC Phase II proceeding.

Answer Part B, Question 4, subpart e. Distribution Tracking. **This response contains confidential customer information provided pursuant to the NDA in A.16-06-013.** Information provided in response to this question is in GRC-2017-PhII_DR_AGParties_DataRep_2019_B-Q04e_SUPP01-Atch03CONF. Annual non-coincident demand by schedule is provided in response to this request. For reference, PG&E has also provided residential and small commercial diversity factors from the last GRC which were used to develop FLT loads. Non coincident demand and diversity factors provided in response to this question were based on the methods used in the past for generating FLT values. PG&E revised its method for Distribution FLT loads in its 2020 GRC Phase II proceeding.

PACIFIC GAS AND ELECTRIC COMPANY
2017 General Rate Case Phase II
Application 16-06-013
Data Response

PG&E Data Request No.:	CFBF_005-Q01		
PG&E File Name:	GRC-2017-PhII_DR_CFBF_005-Q01		
Request Date:	January 9, 2017	Requester DR No.:	005
Date Sent:	January 17, 2017	Requesting Party:	California Farm Bureau Federation
PG&E Witness:	Amitava Dhar	Requester:	Karen Mills

QUESTION 1

Please provide total peak demand for each customer class, by division, in each year from 1995-2016. If PG&E is unable to provide data from each of these years, please provide the available data.

ANSWER 1

PG&E has data from 1999 through 2014, which are presented in the attached excel file "GRC-2017-PhII_DR_CFBF_005-Q01Atch01.xlsx". PG&E does not have requested FLT data available for the other years requested.

PACIFIC GAS AND ELECTRIC COMPANY
2017 General Rate Case Phase II
Application 16-06-013
Data Response

PG&E Data Request No.:	CFBF_006-Q01		
PG&E File Name:	GRC-2017-PhII_DR_CFBF_006-Q01		
Request Date:	January 30, 2017	Requester DR No.:	006
Date Sent:	February 15, 2017	Requesting Party:	California Farm Bureau Federation
PG&E Witness:	Amitava Dhar	Requester:	Karen Mills

QUESTION 1

PG&E's responses to DR 5 provided the same FLT data in response to our requests for both peak demand data (Q1) and non-coincident load data (Q2), but we were asking for two different sets of data. We can use the FLT data in response to Q2 (non-coincident load), but we'd like the generation PCAF data in response to Q1 (annual peak demand by class from 1995-2016, by division if available).

ANSWER 1

The generation PCAF data that PG&E currently has available only cover 2002 through 2015. Please find attached the data in file "GRC-2017-PhII_DR_CFBF_006-Q01 Atch01.xlsx".

PACIFIC GAS AND ELECTRIC COMPANY
2017 General Rate Case Phase II
Application 16-06-013
Data Response

PG&E Data Request No.:	CFBF_006-Q02		
PG&E File Name:	GRC-2017-PhII_DR_CFBF_006-Q02		
Request Date:	January 30, 2017	Requester DR No.:	006
Date Sent:	February 1, 2017	Requesting Party:	California Farm Bureau Federation
PG&E Witness:	Tysen Streib	Requester:	Karen Mills

QUESTION 2

PG&E's response to DR 4 Q3 attachment 3 provides distribution PCAFs from 1999-2007 and from 2009-2010. It appears that the 2008 data was inadvertently excluded. Please provide these data.

- In addition, the distribution PCAF data does not include a list of the peak intervals included in the PCAFs. We can put this aspect of the request on hold for now since it's a lower priority item at this time, but we may ask for it later.

ANSWER 2

Attachment GRC-2017-PhII_DR_CFBF_006-Q02_Atch.xlsx now contains the missing 2008 data from CFBF_004-Q03.

Economic Research Service
United States Department of Agriculture

Data Files: U.S. and State-Level Farm Income and Wealth Statistics

Data Files: U.S. and State-Level Farm Income and Wealth Statistics

These are the latest data concerning the farm income forecast, including the forecasts for the income statement for the U.S. farm sector, value added, cash receipts and value of production, government payments, farm production expenses, and the balance sheet. Included are historical U.S. and State-level farm income and wealth statistics. Historical/State data cover the topics of net value added and net farm income, net cash income, cash receipts and value of production, government payments, farm production expenses, and the balance sheet.

Data are released three times a year: typically, in February, August, and November. The U.S.-level calendar-year forecast is first provided in February and is updated in August and November. The August release converts the prior year's farm income and balance sheet forecasts to estimates, adds State-level farm income estimates, and revises previous years' estimates. The November release updates the current year's forecast and revises previous years' estimates, as needed.

Data are as of September 2, 2020, unless noted. The next scheduled forecast release is December 2, 2020. These tables cover the full history of data through 2020F, where available.

Summary of U.S. Farm Income Financial Indicators

- U.S. farm sector financial indicators, 2013-20F
  Includes the U.S. income statement and balance sheet summary.
- Farm sector financial indicators, State rankings

Farm Income Statements, U.S. and States

- Value added by U.S. agriculture (includes net farm income)
- Net cash income
- Returns to operators

Cash Receipts

- Annual cash receipts by commodity, U.S. and States, 2008-2020F

- Annual cash receipts by commodity (condensed), U.S. and States, 1910-2020F
- Ranking tables: Choose a State to get ranked commodities
- Ranking tables: Choose a commodity to get ranked States

Government Farm Program Payments

- Federal government direct farm payments by program, U.S. and States

Production Expenses

- Production expenses, U.S. and States
- Production expenses by type, State ranking
- Gross capital expenditures, U.S.

Farm Balance Sheet and Financial Ratios, U.S.

- Farm sector balance sheet and selected financial ratios
- Farm sector financial ratios
- Current and noncurrent farm sector balance sheet (includes current and working capital ratios)

Average (Farm-level) Net Cash Income, U.S.

- Farm-level average net cash income by farm typology and sales class
- Farm business average net cash income by commodity specialization and region

Charts and Maps Data Visualizations

- Charts and Maps About Your State
- Charts and Maps of U.S. Farm Sector Balance Sheet Data
- Charts and Maps of U.S. Farm Income Statement Data

Download All Data in CSV File Format (ZIP)

- September 2, 2020 release
- February 5, 2020 release
- November 27, 2019 release
- August 30, 2019 release (revised September 3, 3019) includes corrected 2019F asset, equity, and financial ratio data; see Update and Revision History.
- March 6, 2019 release
- November 30, 2018 release

- August 30, 2018 release
- February 7, 2018 release (revised July 17, 2018) includes data from modified reports, see Update and Revision History.
- November 29, 2017 release
- August 30, 2017 release
- February 7, 2017 release
- November 30, 2016 release
- August 30, 2016 release
- February 9, 2016 release (revised May 2, 2016) includes data from modified reports, see Update and Revision History.
- November 24, 2015 release
- August 25, 2015 release
- February 10, 2015 release
- November 25, 2014 release (revised December 12, 2014)
- August 26, 2014 release

Archive of Suspended Tables

The estimation of State-level balance sheet and liquidity/efficiency and solvency/profitability ratios has been suspended. Data for 1960-2003 for all 50 States are included in a ZIP file.

- State-level farm sector balance sheets, 1960-2003
- State-level farm sector liquidity/efficiency and solvency/profitability ratios, 1960-2003

Farm Income and Wealth Statistics

Overview

▸ Data Files: U.S. and State-Level Farm Income and Wealth Statistics

Summary of Data Findings

Charts and Maps About Your State

Charts and Maps of U.S. Farm Balance Sheet Data

Charts and Maps of U.S. Farm Income Statement Data

Update and Revision History

General Documentation

Documentation for the Farm Sector Cash Receipts Estimation

Documentation for the Farm Sector Balance Sheet

Documentation for the Farm Sector Financial Ratios

Related Topics

Farm Labor

Federal Tax Issues

Beginning, Limited Resource, Socially Disadvantaged, and Female Farmers

Farm Household Well-being

Farm Economy

Dairy

Farm Sector Income & Finances

Farm Structure and Organization

Land Use, Land Value & Tenure

ERS Coronavirus (COVID-19) Media Resources

Last updated: Friday, November 13, 2020

For more information, contact: Farm Income Team

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Iowa
Kansas
Kentucky
Louisiana
Maine
Maryland
Massachusetts
Michigan
Minnesota
Mississippi
Missouri
Montana

Cash income statement, 2011-2020F
Nominal (current dollars)

California	2011	2012	2013	2014	2015	2016	2017	2018	2019
	$1,000	*$1,000*	*$1,000*	*$1,000*	*$1,000*	*$1,000*	*$1,000*	*$1,000*	*$1,000*
Gross cash income	45,444,725	50,039,182	54,193,915	59,715,541	51,875,187	49,906,473	52,866,710	51,640,671	52,888,087
All commodity receipts	43,217,001	46,954,450	51,598,976	56,930,946	49,108,446	47,528,364	49,578,643	49,588,742	50,116,898
Crop receipts	31,040,641	34,769,669	38,792,399	41,564,129	37,292,619	37,047,619	38,388,835	37,777,026	37,777,752
Animals and products receipts	12,176,360	12,184,781	12,806,578	15,366,817	11,815,826	10,480,745	11,189,809	11,811,716	12,339,146
Cash farm-related income	1,968,661	2,797,200	2,346,228	2,537,946	2,531,307	2,137,295	3,109,388	1,776,455	2,351,260
Forest products sold	1,379	9,496	10,756	14,357	7,550	8,219	5,722	3,865	2,918
Machine hire and customwork	739,800	837,477	832,656	524,735	913,959	396,078	1,253,201	599,988	989,352
Other farm income	1,227,482	1,950,226	1,502,816	1,998,854	1,609,799	1,732,999	1,850,465	1,172,601	1,358,989
Total direct government payments	259,063	287,532	248,711	246,649	235,434	240,813	178,679	275,474	419,930
Cash expenses 1/	29,552,788	32,266,041	34,851,752	37,633,325	33,393,898	33,113,544	36,322,839	35,736,451	40,886,398
Interest 1/	1,511,727	1,516,619	1,359,734	1,432,729	1,484,481	1,578,800	1,682,374	1,867,140	1,907,477
Nonreal estate	498,277	535,985	446,859	472,983	507,421	515,978	551,652	619,544	605,595
Real estate 1/	1,013,450	980,634	912,875	959,746	977,061	1,062,823	1,130,723	1,247,595	1,301,882
Labor expenses	7,454,468	8,240,271	8,809,118	9,646,897	9,194,055	9,819,989	11,643,320	10,131,876	12,307,647
Property taxes and fees 1/	1,003,210	973,563	1,025,719	1,056,397	1,083,601	1,009,422	1,116,168	1,146,412	1,285,004
Farm origin	6,994,360	7,651,938	8,435,923	6,888,755	6,363,073	6,194,108	6,294,322	6,926,473	7,269,365
Feed purchased	5,110,000	5,490,000	6,170,000	4,750,000	4,050,000	3,930,000	3,400,000	4,500,000	4,700,000
Livestock and poultry	814,360	821,938	805,923	798,755	783,073	514,108	754,322	936,473	809,365
Seed	1,070,000	1,340,000	1,460,000	1,340,000	1,530,000	1,750,000	2,140,000	1,490,000	1,760,000
Manufactured inputs	4,765,874	5,278,882	5,787,134	7,002,518	6,085,322	6,203,181	6,067,639	6,172,488	7,194,659
Electricity	670,358	854,983	1,036,989	1,193,366	1,152,776	1,018,296	1,085,192	1,123,243	1,101,580
Fertilizer and lime	1,620,000	1,610,000	1,850,000	2,350,000	2,060,000	2,150,000	1,980,000	2,030,000	2,280,000
Fuel and oil	1,185,517	1,363,899	1,300,145	1,379,152	1,222,545	1,194,885	1,092,447	1,019,244	1,383,078
Pesticides	1,290,000	1,450,000	1,600,000	2,080,000	1,650,000	1,840,000	1,910,000	2,000,000	2,430,000

Nebraska
Nevada
New Hampshire
New Jersey
New Mexico
New York
North Carolina
North Dakota
Ohio
Oklahoma
Oregon
Pennsylvania
Rhode Island
South Carolina
South Dakota
Tennessee
Texas
Utah
Vermont
Virginia
Washington
West Virginia
Wisconsin
Wyoming

Other intermediate expenses 1/	6,791,289	7,136,990	7,935,130	9,897,678	7,662,939	6,937,177	7,972,233	8,278,331	8,964,404
Net rent to landlords 2/ 3/	1,031,858	1,467,778	1,498,994	1,708,352	1,520,428	1,370,867	1,546,783	1,213,731	1,957,842
Net cash income	15,891,937	17,773,141	19,342,163	22,082,216	18,481,289	16,792,929	16,543,871	15,904,219	12,001,690

Footnotes
Data as of September 2, 2020
F = Forecast values.
NA = Data are not available/applicable.
Values are rounded to the nearest thousand. When 'Real (2020 dollars)' is selected, nominal values are adjusted for inflation using the chain-type GDP deflator, base year=2020.
1/ Excluding expenses associated with operator dwellings
2/ Excluding landlord capital consumption
3/ Prior to 2008 estimates, net rent to landlords only includes the portion paid to nonoperator landlords.

USDA/ERS Farm Income and Wealth Statistics

Last updated: September 02, 2020

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PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2020 Forecast
Application 20-07-002
Data Response

PG&E Data Request No.:	AgParties_001-Q06		
PG&E File Name:	ERRA-2021-PGE-Forecast_DR_AgParties_001-Q06		
Request Date:	August 7, 2020	Requester DR No.:	001
Date Sent:	August 31, 2020	Requesting Party:	Agricultural Energy Consumers Association
PG&E Witness:	Andrew Klingler	Requester:	Ann L. Trowbridge

QUESTION 06

Please provide the complete set of economic factor load forecasts used for developing the agricultural load forecast.

ANSWER 06

The economic factor noted in the regression model as "AG_OUTPUT" is the Gross Product: Agriculture; Forestry; Fishing and Hunting (Mil. $).

Please see "02. ERRA 2021-Forecast_WP_PGE_20200717_Ch02_Table 2-3_Sales_rev1_PUB.xlsx", tab "Ag_kwh_data," column Q, from the set of public workpapers accompanying PG&E's July 17, 2020 supplemental testimony and available at this website:
http://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=615854.

Parties can obtain access to PG&E's confidential workpapers upon execution of a Nondisclosure Agreement.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2020 Forecast
Application 20-07-002
Data Response

PG&E Data Request No.:	AgParties_001-Q07		
PG&E File Name:	ERRA-2021-PGE-Forecast_DR_AgParties_001-Q07		
Request Date:	August 7, 2020	Requester DR No.:	001
Date Sent:	August 31, 2020	Requesting Party:	Agricultural Energy Consumers Association
PG&E Witness:	Andrew Klingler	Requester:	Ann L. Trowbridge

QUESTION 07

Please provide the past referenced economic data and forecasts for the past 20 years from the vendor that PG&E is relying on for its agricultural economic activity forecast.

a. If PG&E does not have a complete set of past data and forecasts from the vendor for at least 20 years, please explain how PG&E determined the veracity and validity of the vendor's past forecasting performance and conformance with official national and state agricultural economic data.

b. Has PG&E calibrated the agricultural economic forecasts from the vendor that it is using against 1) historic US Department of Agriculture data on agricultural economic data, and 2) historic USDA economic activity forecasts? If so, please provide the findings of those calibrations. If not, please explain why PG&E has not done such an analysis.

ANSWER 07

The attachment to this data response contains Confidential Information submitted under the Nondisclosure Agreement between PG&E and ACEA's reviewing representative Richard McCann

Please see Confidential Attachment 1 of this data response (see Excel file, "ERRA-2021-PGE-Forecast_DR_AgParties_001-Q07Atch01-CONF.xlsx") which contains five years of Agriculture Output data from Moody's.

a. The five data sets are dated December 2016, and mid-year of 2017, 2018, 2019 and 2020 respectively. The time series begins in January of 2000 and runs through December of 2021. This enables an estimation of a regression model and a forecast of the agriculture sales load.

   The model changed in 2016 and PG&E introduced the agriculture output variable to the regression model. Prior to 2016 the regression model contained water availability variables based on Sacramento and Fresno rainfall. PG&E had historical rainfall data and forecast the future rainfall in each month by using the last observable corresponding month's value.

In 2016 PGE contacted Moody's to request the Agriculture Output variable to include in the regression model. The Moody's variable is produced for the PG&E service territory and therefore was considered the most accurate representation for the region. The USDA data is not specific to the PG&E service territory.

b. No. PG&E does not know which specific data and statistics the parties would like PG&E to calibrate against its vendor's data nor whether it can be mapped to PG&E's service territory for such analysis. By default, USDA forecasts do not correspond directly to PG&E's service territory.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2021 Forecast
Application 20-07-002
Data Response

PG&E Data Request No.:	AECA_002-Q02		
PG&E File Name:	ERRA-2021-PGE-Forecast_DR_AECA_002-Q02		
Request Date:	October 13, 2020	Requester DR No.:	002
Date Sent:	October 26, 2020	Requesting Party:	Agricultural Energy Consumers Association
PG&E Witness:	Andrew Klingler	Requester:	Ann Trowbridge

QUESTION 02

Referring to PG&E's Rebuttal at page 29, PG&E notes that its Ag sales forecast have been above the actual sales the last several years. However, Ag sales fall in "wet" water years as groundwater pumping loads decrease with increased water availability. (See for example, CDWR Water History data set for 2017 to 2019 at: https://cdec.water.ca.gov/reportapp/javareports?name=WSIHIST)

a. Please provide what PG&E's forecasted load would be for 2000 to 2019 using actual water conditions for those years.

b. Please provide what PG&E's forecasted load would be for 2000 to 2019 using "normal" water conditions for those years based on PG&E's definition of "normal."

ANSWER 02

Please see Attachment 1 to this data response (see Excel filename, "ERRA-2021-PGE-Forecast_DR_AECA_002-Q02Atch01.xlsx"). The tab named "Actual Water Year Forecast" is responsive to the request in subpart (a) and the tab named "Normal Water Year Forecast" is responsive to the request in subpart (b).

PG&E defines normal water conditions for each month by taking the average of the recorded water year variable for that month for time period of 2000 through 2019. This is done for each month January through December.

The first 11 observations in each tab are historical values and the forecasted values start in December of 2000 for both time series.

Effective Water Pricing

by

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Effective Water Pricing

Abstract

When the goal of water pricing is elevated from mere cost recovery to deriving the greatest value from scarce water and associated nonwater resources, conventional rate regimes are found to be deficient. To address the challenge of creating rates that are both efficient and budget-balancing, several theoretical and practical aspects of rate-making are considered. Purposeful selection of rate parameters for a specific billing system is demonstrated to serve efficiency and cost recovery objectives. Attention to nonaccounting opportunity costs is an important system element, but these costs are often not fully borne by the utility or its customers. In situations where this issue is serious, state or federal pricing policy may be necessary.

Key terms: water pricing, water rates, water tariffs, block rate pricing

Effective Water Pricing

Introduction

The costs of municipal water supply are outpacing inflation due to three inexorable forces: heightened water scarcity, growing infrastructure costs, and rising health and environmental regulation. One implication of these forces is water cost increases that raise water rates. As a consequence, progressively greater public scrutiny is being visited upon the pricing policies of water utilities, and this situation promises to intensify as water bills continue to rise and alert consumers. Simultaneously, more attention will be drawn to the policies governing the establishment of water rates.

Up to this point in time, and likely beyond judging from current inertia, both rate-setting policies and governing rules have been dominated by accoun ting conventions rather than by economic ones (see, for example, American Water Works Association 1991). The difference can be substantial (Martin et al. 1984). Accounting conventions emphasize revenue neutrality, that is, rate levels that generate revenue just sufficient to cover costs. Such a goal appears sensible, even equitable. Economic conventions concentrate upon the role of price in determining the welfare of consumers. Here, price is perceived as double-edged. Price has an obvious impact on household finances and production costs for water-using businesses. Additionally, because price modifies water consumption behavior (and utilities strive to provide the quantity consumers demand), it affects supply costs. These two "edges" work in opposing directions, and the economic perspective is to select prices that make the best tradeoff in advancing consumer welfare.

Whereas some water managers embrace the fairy tale that water is unique among all commodities and does not have price-sensitive demand, decades of econometric studies falsify this claim (Espey, Espey, and Shaw 1997). Indeed, the much celebrated potential of water marketing (Easter, Rosegrant, and Dinar 1998; National Research Council 1992) to remedy water scarcity is likely to be surpassed by the promise of pricing due to the influence of price on consumption.

Marketing shapes the allocation of water among water purveyors (e.g. urban utilities and irrigation districts), but its real impact on individual water users disappears once the debt of a water right purchase is retired. On the other hand, improved pricing policy affects all water users' behavior while also influencing the supply and demand forces that drive water markets.

Because of the increasing relevance of water pricing policy, the objective of this paper is to unify and extend the economic depiction of proper water pricing. While the adopted context pertains to municipal water pricing, the full analysis is equally applicable to irrigation districts supplying metered water. The discussion begins with a short treatment of possible pricing goals and the establishment of a basic model for designing water prices. The primary elements of the model depart from those of general public utility literature in some key respects in order to concentrate on the unique attributes of water service, and these differences are observed once the basic pricing model has been presented. Following this, three distinct categories of nonaccounting opportunity costs are individually considered. In each case, the pricing model is extended to capture the pricing implications of the added concern. Because some of these opportunity costs are external to utilities, corrective policy is suggested.

A Basic Pricing Model

Fundamental social questions about water pricing concern the merits of alternative rate structures in terms of social desires for efficiency, equity, and revenue neutrality. Conservation enhancement is an additional desire, but we must be careful not to undertake conservation where more valuable resources are substituted for water (Baumann, Boland, and Sims 1984). Consequently, economic efficiency is a sufficiently encompassing objective to include deserving conservation.

In the case of equity, public concerns pertain largely to ability-to-pay issues, but in some circumstances there are also social preferences to force "water hogs" to pay higher rates. With regard to water hogging, the economic finding is that water overuse is an artifact of water

underpricing, and once prices embed the appropriate social values the need to penalize large water users evaporates.

With respect to ability-to-pay matters involving low-income households and elderly fixed-income households, the social issue is certainly legitimate. However, care should be exercised in viewing water service as a welfare program, because government involvement in water service historically arose from the sizeable amount of capital needed to establish water services or the natural monopoly character of water delivery, not from welfare issues relating to income distribution. Water bills should be perceived as what they are: requests for payment for a valued, delivered service, not a tax invoice for funding government programs. Water rates do not have a comparative advantage in correcting income inequity, and such attempts can be damaging to both efficiency and conservation objectives. With that said, the billing system to be emphasized later does possess positive attributes in moderating the water bills of low-volume water users.

While one must be realistic about seeking rates that serve multiple objectives, interesting schemes do exist for pursuing efficiency, revenue neutrality, and some degree of equity simultaneously. To explore this topic in a purposeful manner, it is useful to initially set aside the practical matters of peak loads, reliability, seasonality, depletion, and wastewater/sewerage. Next, a basic pricing model is formulated to examine the properties of desirable water rates and to provide a platform for testing alternative rate systems.

Model Notation

Suppose that our utility serves N baseline clients or connections. Each of these clients is connected by existing infrastructure (sunk costs) to the present system. In addition to existing clients, there are ΔN additional clients who will become connected to the system within the current fiscal period. The ΔN prospective clients may include households and firms relocating to the area's newly developed properties, existing clients relocating to newly developed properties, and any peripheral properties not currently receiving water service. While the usual economic convention is to treat any "Δy" as an incremental extension of "y," explicit attention to ΔN underscores the important cost implications of extending water service to new customers.

Each existing or new connection garners a benefit from water use, and this benefit is dependent on the amount of water consumed. Because both water use and its value may be unique to the client, let $B_n(w_n)$ represent the n^{th} connection's benefit of consuming w_n units of water where $n \in S = \{1,2,...,N,N+1,...,N+\Delta N\}$.

C(W,N,ΔN) represents the utility's single period cost of serving N+ΔN connections that use a total of W units of water. This cost function is defined in such a way that a new connection increases costs by $\partial C / \partial N + \partial C / \partial \Delta N$ even without any metered water use, meaning that $\partial C / \partial \Delta N$ is only the extra costs of a new connection (for added infrastructure and water supplies) above those of an existing connection. It is also assumed that this cost function embodies a least-cost package of water sources, infrastructure, and administration, as is customary for cost functions. For consistency with the benefit functions, the cost function is expressed as a function of delivered (billed) water, rather than produced (billed plus lost) water. Hence, $W = \sum_{n=1}^{N+\Delta N} w_n$.

By recognizing costs as functionally dependent on N and ΔN, two important facts are acknowledged. First, utilities face noteworthy operational costs that cannot be properly attributed to the amount of delivered water. For example, the maintenance of some forms of system infrastructure (e.g. storage tanks) is largely independent of water consumption. The same is true of costs due to meter reading, billing, customer service, and some aspects of administration (Martin et al. 1984). Even the water lost to distribution leakage is a consequence of maintaining a pressurized, ready-to-serve, albeit imperfect system. That is, the water cost of these leaks typically changes but slightly in response to altered water deliveries. Second, the costs of system growth for adding new connections is often laden with substantial nonwater and water costs. New infrastructure is costly to design, approve, and install. Moreover, growth commonly entails additional investments in water supply, and in water-scarce environments new water supplies can cost much more than they have in the past. In light of these observations, one must wonder if the common economic presumption of decreasing average costs in water supply is the erroneous result of associating all costs with water only, as if the cost function is well represented by C(W).

The direct incorporation of N and ΔN as cost function arguments permits study of rate structures' impacts on the allocation of both water and nonwater resources. This matter is rarely contemplated in water resource economics, even though it is of substantial importance in water resource accounting and rate design. Although the costs attributable to each existing connection may be functionally related to unique characteristics of the connection, in this basic model it is assumed that all existing connections are homogeneous with respect to their influences on costs. Similarly, all new connections are assumed to be have identical impacts on costs. Relaxations of these simplifications will be addressed later.

Establishing Economic Efficiency

Within this modeling framework there are three types of decisions that we wish to examine: water consumption by each customer, continuation of service by existing customers, and enrollment decisions by prospective new connections. The primary objective is to design a rate structure that encourages customers to make economically efficient consumption, continuation, and enrollment decisions. Balancing the utility's budget is an additional objective that we wish to achieve.

To consider enrollment decisions by prospects, a multiperiod definition of economic efficiency is necessary. Here, we adopt the customary norm that efficiency is achieved when the present value of net social benefits is maximized over all current and prospective connections. Adding time (t superscripts) where needed to previous notation, the following optimization problem is obtained.

$$\text{Max } PV(\underline{\underline{w}}, \underline{N}, \underline{\Delta N}) = \sum_{t=0}^{T} \rho^t \left[\sum_{n=1}^{N^t+\Delta N^t} B_n^t(w_n^t) - C^t\left(\sum_{n=1}^{N^t+\Delta N^t} w_n^t, N^t, \Delta N^t \right) \right] . \qquad [1]$$

PV is the present value function employing a planning horizon of T. $\underline{\underline{w}}$ is the Tx(N+ΔN) matrix of water consumption by all connections in all time periods. $\underline{N}$ and $\underline{\Delta N}$ are both Tx1 vectors. ρ^t is the discounting factor; this is the only instance in [1] in which t serves as an exponent. It is assumed here that consumer and utility rates of discount are equivalent. In considering [1] we

employ the convention that we are only interested in determining ΔN^t for the present time period, t=0. In future time periods, [1] can be reformulated and resolved with updated information, so the resolution of future decisions is not presently interesting. Any newly enrolled connections will contribute substantially to present costs, C^0, but once they are connected, their recurring costs will be no different than those for existing connections.

Only the decision of ΔN considers future periods in equation [1]. Water consumption and service continuation are static issues here, so it is practical to study these two decisions using the net benefits subproblem that is embedded in [1]. The static subproblem is to determine water use decisions and service continuations that maximize net benefits in the current planning period:

$$\text{Max } NB(\underline{w}, N) = \sum_{n=1}^{N+\Delta N} B_n(w_n) - C\left(\sum_{n=1}^{N+\Delta N} w_n, N, \Delta N\right) . \qquad [2]$$

Here, NB denotes net benefits and $\underline{w}$ is the 1x(N+ΔN) vector of water consumption by all connections.

Solving the subproblem [2], we differentiate NB with respect to each w_n and set the result equal to zero. The result is

$$\frac{dB_n}{dw_n} = \frac{\partial C}{\partial W} \quad \text{for all } n \in S. \qquad [3]$$

This is the requirement for equality between marginal benefits and marginal costs of water consumption for all connections. This is the necessary condition for allocating water efficiently.

Differentiating NB with respect to N and setting the result equal to zero, we obtain

$$B_N(w_N) = \frac{\partial C}{\partial W} w_N + \frac{\partial C}{\partial N} \quad . \qquad [4]$$

According to the first-order condition [4], the benefits received by connection N, the system's marginal continuing connection, should equal the marginal costs of serving connection N. For every nonmarginal existing connection, benefits should exceed the marginal costs of servicing the connection.

Moving to the optimization of new connections, the necessary condition emerging from [1] is

$$\sum_{t=0}^{T} \rho^t \left[B^t_{N^0+\Delta N^0}\left(w^t_{N^0+\Delta N^0}\right) - \frac{\partial C^t}{\partial W^t} w^t_{N^0+\Delta N^0} - \frac{\partial C^t}{\partial N^t} \right] = \frac{\partial C^0}{\partial \Delta N^0} \ . \qquad [5]$$

The left side of this equality is the present value of net benefits attributed to present and future water consumption by the marginal new connection, ΔN^0. The right side is the system cost of adding this user. For every nonmarginal new connection, the present value of net benefits (left side of [5]) should exceed the marginal costs of adding the connection (right side of [5]).

These necessary conditions, [3]-[5], represent economically efficient targets for allocating water resources, connection resources, and new connection resources for the community. Utility managers do not directly decide these matters, however. Consumers do. But consumers make their decisions in the context of policies established by utility management. The pivotal question and the focus of this paper is: Is there a pricing policy which motivates consumers to make socially optimal decisions while preserving the nonprofit status of the utility?

Developing Efficient Rates

Let us propose the following multipart rate system. The first component is that new connections are required to pay a one-time fee designated by F_Δ. Once they pay this connection charge and become part of the utility's customer base, they are regarded as existing customers. Whether this fee is paid by a property's developer or its first occupant is inconsequential, because the developer will incorporate the fee in the property's price.

The second component is that all connections pay for their metered water consumption according to the following billing formula:

$$\text{Bill}_n = M + p\cdot(w_n - \bar{w}) . \qquad [6]$$

This billing formula should not be confused with the typical two-block rate structure which is well represented by the following equation:

$$\text{Bill} = \begin{cases} \text{meter charge} & \text{if } w_n \le \omega \\ \text{meter charge} + \rho \bullet (w_n - \omega) & \text{if } w_n > \omega \ . \end{cases}$$

The latter billing formula is included here only for comparison purposes. It includes two water prices (unless $\omega = 0$, implying a single block), and it fails to provide efficient price signals for low-volume water users.

Billing system [6] has three parameters that must be optimized: M, p, and $\overline{w}$; w_n is metered water consumption. M is a fixed "meter charge" to be paid each period. This charge is equivalent for all customers as it is unrelated to metered water consumption, and homogeneous clients have been assumed thus far. p is the price of water. As there are no blocks in this rate structure, every connection faces the same marginal price of water (p). $\overline{w}$ is the "bill threshold". For connections that consume exactly the bill threshold, the bill will consist only of the meter charge. For connections consuming more than the bill threshold, they will pay, in addition to the meter charge, p for every unit of water exceeding the threshold. For connections consuming less than the bill threshold, a *credit* of \$p will be generated by every unit of water consumed below $\overline{w}$. Should this credit exceed the meter charge, the customer will receive a payment rather than a bill.

When parameterized correctly, this atypical rate structure provides economically efficient incentives for consumers, a trait not shared with conventional rates. The general purpose of each part of the rate is as follows. F_Δ induces efficient connection decisions by new customers and offers a means of cost recovery for system extensions. M has two purposes too. In the unlikely event that a customer's water service benefits fall below utility-incurred costs, M encourages the customer to discontinue service. More importantly, it is a means of collecting service costs functionally related to connection costs rather than water costs. Hence, F_Δ and M address the efficient allocation of nonwater resources, although F_Δ will also include the cost of water acquisitions in water-scarce regions. The purposes of p are to allocate water efficiently and to recover costs. Lastly, $\overline{w}$ is a budget-balancing parameter, introduced as a substitute mechanism for the average-cost pricing of water, which is the traditional method of balancing utility budgets. The deployment of $\overline{w}$ makes each connection a shareholder in the system. Should the utility generate an economic surplus, it is dispersed uniformly across all connections using this

instrument. If optimal prices result in a net financial loss for the utility, $\bar{w}$ will be negative and it serves to collect the shortfall from all connections equally. Again, these findings are specific to the model structure which includes homogeneous consumers. If the utility serves clients of different classes, e.g. residential or commercial, there may be grounds for establishing different $\bar{w}$'s.

To develop optimal rate parameters, F_{Δ}^{*}, M^{*}, p^{*}, and $\bar{w}^{*}$, consider first the water consumption decision of an existing customer. The n^{th} connection rationally selects a consumption level that maximizes own net benefits. This presents the following problem:

$$\text{Max} \quad NB_n(w_n) = B_n(w_n) - M - p\cdot(w_n - \bar{w}). \qquad [7]$$

Solving N+ΔN of these problems gives rise to the following set of first-order conditions:

$$\frac{dB_n}{dw_n} = p \quad \text{for all } n \in S. \qquad [8]$$

Comparing [8] to [3] we find that economic efficiency is advanced by marginal-cost pricing. That is, in an efficient rate structure, we must have

$$p^{*} = \frac{\partial C}{\partial W}. \qquad [9]$$

Every connection must face the same price of water, and that price must be identical to the system's marginal cost of supplying water. Thus, we have determined one parameter of the three that specify the billing system given by [6]. According to this result, there are three general aspects of contemporary rate structures which are deficient. First, low-volume water users face a zero price of water in the common system of entitling each connection to a certain quantity of free water. Second, multiblock systems contain more than one price of water. Third, rates are commonly founded on average costs rather than marginal costs. These deficiencies may advance revenue neutrality goals, but they are clearly inefficient with respect to water allocation.

With respect to continuing connections, the marginal customer, client N, will be indifferent to maintaining service when benefits received are precisely offset by the bill. Expressed mathematically,

$$B_N(w_N) = M + p\cdot(w_N - \bar{w}).$$

Substituting from the optimality condition [4] and the optimal water pricing rule [9],

$$\frac{\partial C}{\partial W} w_N + \frac{\partial C}{\partial N} = M + \frac{\partial C}{\partial W} \cdot (w_N - \bar{w}),$$

and solving for the meter charge, we obtain

$$M = \frac{\partial C}{\partial N} + \frac{\partial C}{\partial W} \bar{w}. \qquad [10]$$

Intuition readily suggests the first term of the right-hand side of this equality but not the second, which constitutes a precise offset of the budget-balancing mechanism introduced by $\bar{w}$. The second term emerges in the above derivation in order to prevent consumers from maintaining service mainly to receive their "rent share". On the other hand, the combined result of [6], [9], and [10] is to eliminate the budget-balancing term, $\bar{w}$, from the billing structure given by [6].

It is difficult to design a rate structure that serves multiple masters, in this case efficiency and revenue neutrality. The billing system [6] does not distribute revenue excesses or shortfalls in a fully lump-sum manner (they only go to active connections), so something has to be sacrificed. Either we abort the pursuit of efficiency or we abort balanced budgets. In the present case, it seems very sensible to select balanced budgets over allocative efficiency in the continuation of connections. The lowered meter charge given by [11] is arguably a proper tradeoff for this issue.

$$M^* = \frac{\partial C}{\partial N}. \qquad [11]$$

Relative to other factors, capturing rent share should be a very small enticement to continue service, so little allocative efficiency should be lost specifying the meter charge with [11] rather than [10]. If a property is idled or vacant and therefore consumes no water, its owner may wish to continue service if rent share exceeds the meter charge (thereby causing an allocative inefficiency), but this problem is virtually negated by the opportunity cost of land and buildings, which make it costly for property owners to maintain idle connections.

Next we consider the decision calculus of a prospective connection. Once the enrolling connection pays F_Δ, it is eligible to receive the present and future benefits of water deliveries from

the utility. This is sensible to the prospect if the present value of net benefits exceed F_{Δ}. For the indifferent (marginal) prospect designated as ΔN,

$$F_{\Delta} = \sum_{t=0}^{T} \rho^{t}\left[B^{t}_{N+\Delta N}(w^{t}_{N+\Delta N}) - M - p \cdot (w^{t}_{N+\Delta N} - \bar{w})\right] .$$

When the prior results embodied in the pricing findings [9] and [10] and the social optimality condition [5] are substituted into this expression, we obtain the optimal fee for new connections:

$$F^{*}_{\Delta} = \frac{\partial C^{0}}{\partial \Delta N^{0}} . \qquad [12]$$

This rule is the intuitively expected result. New additions to the system must pay the marginal costs of their new connections. To do otherwise encourages nonoptimal expansion and detracts from the social net benefits of water service in the community.

The final billing parameter to be resolved is the billing threshold, $\bar{w}$. Rather than being efficiency-based, the billing threshold acts to balance the utility's budget. Hence, it is obtained by finding that level of $\bar{w}$ for which utility revenues are equivalent to costs. In the following expression, revenues are assembled on the left side of the equation; costs are on the right:

$$F^{*}_{\Delta}\,\Delta N + M^{*} \bullet (N + \Delta N) + p^{*}W - p^{*}\bar{w} \bullet (N + \Delta N) = C(W, N, \Delta N) .$$

Solving for $\bar{w}$ yields the optimal billing threshold,

$$\bar{w}^{*} = \frac{F^{*}_{\Delta}\,\Delta N + M^{*} \bullet (N + \Delta N) + p^{*}W - C(W, N, \Delta N)}{p^{*} \bullet (N + \Delta N)} . \qquad [13]$$

Looking beyond the complex appearance of [13], $\bar{w}^{*}$ is the level of the billing threshold necessary to assign all revenue shortfalls or to disperse all rents/profits accruing to the utility. While there are certainly other candidate mechanisms for achieving revenue neutrality, this one is straightforward, and it introduces a measure of fairness by treating all connections as equal partners in the utility. Most importantly, unlike average-cost pricing, the billing threshold does not impede the efficient allocation of water resources.

Depending on cost function properties relating to returns to scale, it is possible for the numerator of [13] to be negative, in which case $\overline{w}$ is negative and its purpose is to assign responsibilities for revenue shortfalls. In such cases, $\overline{w}$ performs the same service as the second part of the two-part tariff idea that was promulgated long ago for utilities experiencing decreasing average costs (Kahn 1988, Ch. 4).

General Public Utility Pricing Theory

Economic literature pertaining to public utilities has had a longstanding interest in efficient pricing, so it is useful to consider both the overlap and departures of the above water pricing results in relation to the more general literature. Public utility economics has provided many contributions (reviewed by Berg and Tschirhart 1995), most of which are not directly germane for the objectives of the pricing model set forth above.

One relevant facet of public utility theory focuses upon the specification of optimal prices for goods supplied by natural monopolies. A natural monopoly is a "firm" operating in a situation in which the introduction of any competition (other firms) would actually lower consumer welfare due to the nature of the cost function for this industry. Loosely speaking, when average costs per unit of output are decreasing across the relevant range of demand, we have a natural monopoly (Baumol 1977). Public utility literature has long scrutinized and espoused the notion of a "two-part tariff" for achieving an economic efficient level of production in natural monopoly situations (Lewis 1941; Brown, Heller, and Starr 1992). The first part involves a marginal cost based price for each unit of the good consumed. The second part involves a flat "access fee" for each consumer, so that the sum of these fees cover revenue shortfalls implied by the fact that marginal costs are lower than average costs for natural monopolies.

The multipart rates of the water pricing model developed here emerge for largely these reasons but not entirely. Optimal water and new connection rates (p and F_{Δ}) are found to be marginal cost prices required to achieve efficiency in the allocation of water and nonwater resources. The "optimal" meter charge (M) deviates from the efficient level in order to preserve

revenue neutrality, but it is the marginal cost of connections, and the efficiency sacrifice should be small. The fourth part of the rate structure, $\overline{w}$, serves to balance the utility's budget, so that it neither suffers a loss nor captures a profit. However, the derivation of this system of water prices did not presume that the cost structure is one of decreasing average costs. Indeed, no structure was assumed for the cost function except to say that it may be functionally dependent upon three primary items, W, N, and ΔN. Average costs may be decreasing, constant, or increasing in these three arguments, and the water pricing results will be unchanged.

Viewed in this way the water price findings are only slightly more general than an extended two-part tariff, but they are also more applicable in some key respects. The sole per unit price of the two-part tariff is a water charge, so nonwater resource costs are implicitly portrayed as being functionally dependent on the amount of supplied water. However, water utilities incur large costs which are functionally unrelated to water deliveries, and consumers make important choices influencing these costs. Additional price signals are needed so that (1) efficiency can be attained for the allocation of nonwater resources and (2) water price signals are not overstated. The separability of water distribution functions from water production functions are well observed within contemporary utility accounting procedures (Raftelis 1993). Therefore, the multipart water tariff developed here serves to bring water pricing theory into compliance with accounting practice as well as the economic implications of separable costs.

It is noteworthy that the public utility literature's assumption of a decreasing cost industry may have declining relevance for water utilities. Water demand growth has generally allowed decreasing-cost ranges of average cost functions to be more fully exploited. Also, when cost functions include the opportunity costs of scarce resources such as water and infrastructure, marginal-cost prices are more likely to generate adequate revenue for the utility. The inclusion of resource opportunity costs is an important matter to be considered later.

Some Refinements

The billing system specified by [6], [9], and [11]-[13] provides socially attractive price signals because the derivation of these prices emphasized efficiency while preserving revenue neutrality. These signals are also water conserving in that any reduction in water use from that motivated here would be socially wasteful, as their benefits would be exceeded by their costs. Of course, the application of this system for any utility hinges upon the elaboration of the cost function, $C(W,N,\Delta N)$, but such cost information is regularly collected as part of recommended accounting practices for contemporary utilities.

There exist certain complexities of water and nonwater allocation that may require more thorough consideration than that undertaken above, but several such complexities are readily entertained through slight extensions of the above theory. Examples include different water types or different connection characteristics having distinguishable effects on the utility's costs. When the costs attributable to water change seasonally, the W term of our cost function should be partitioned appropriately, and we should pursue seasonal prices. The same is true if the utility delivers any water types with different cost implications (e.g. treated water, unprocessed water, and treated wastewater). Likewise, if different customer classes impact costs differently, as with service capacities (pipe sizes), peaking characters, or connection elevations for example, then the cost function should be refined to acknowledge the differential impacts for both continuing connections and, if appropriate, new connections. The result is that the correct cost function may be of the form $C(W_a, W_b, ..., N_i, N_{ii}, ..., \Delta N_i, \Delta N_{ii}, ...)$, and the rate structure will possess $p_a, p_b, ...; M_i, M_{ii}, ...;$ and $F_{\Delta i}, F_{\Delta ii}, ...$. Readily obtained enhancements of [6], [9], and [11]-[13] specify this pricing system completely.

Exploring Marginal Costs

Having established a general framework that demonstrates the sensibility of volumetric water pricing working in concert with nonwater fees, the informational requirements of proper pricing no longer differ much from those underlying normal pricing procedures. Conventional accounting

and pricing practices involve the separation of utility-incurred costs into various categories. An intended purpose of these partitions is to enable the computation of separate prices for water usage and for connections. Consequently, the basis for establishing efficient prices is in place within recommended accounting procedures.

In addition to the inefficiencies of block rate water pricing, conventional pricing practices are deficient in two broader ways. In the first, the correct cost information is misprocessed by calculating average prices rather than marginal prices. Average-cost pricing is only justified when there are legitimate arguments indicating that marginal costs are well approximated by average costs.

The second area of deficiency concerns nonaccounting opportunity costs (NOCs, pronounced "knocks"). Opportunity costs are a fundamental element of economic decision making. An opportunity cost is the value of a foregone option resulting from a decision. In many instances, opportunity costs are accounting costs too (e.g. labor, energy, and land), so there is no difference between the accounting and economic perspectives on what counts. But some opportunity costs do not become accounting costs. These we label NOCs, and when they are significant, accounting-based prices can seriously misvalue either water or nonwater aspects of the rate structure. Due to the great importance of NOCs in certain situations, the following three sections discuss three distinct NOCs and their implications for resolving socially attractive rate structures.

Marginal Value of Raw Water

Interestingly, the lion's share of the rates we customarily pay for finished (tap) water are based on the nonwater resources used as inputs. For the most part, finished water prices are the consequence of value added by the utility for the administration, conveyance, storage, pressurization, and treatment of water. If clients are paying 2¢ per cubic meter at the tap, it cannot be said that added raw water supplies are worth 2¢/m^3. To determine the implicit unit worth of additional raw water, all the value-adding cost items must be subtracted from the 2¢. Such calculations often indicate a zero or near zero value for raw water, because the finished water price

includes no economic rent component (in the case of a nonprofit utility) and the utility possesses a debt-free raw water entitlement. Under these conditions, there is no value assigned to the raw water resource. This is not necessarily bad, because in some times or regions water may not be scarce – meaning that water use involves no forfeitures in sacrificed alternative uses. But when and where water is scarce, finished water prices should incorporate the marginal value of raw water, MVW. This is readily demonstrated.

When the optimization subproblem [2] is augmented to observe water scarcity, the most general approach is to add (a) net benefit functions for the other water users in the watershed and (b) a raw water constraint for the watershed. Alternatively, we can assume that Z* is the optimal raw water allocation to our utility and we must not use more water than that. If L denotes the ratio of raw water lost in conveyance, the utility's constraint is

$$\sum_{n=1}^{N+\Delta N} w_n \le (1-L)\cdot Z^* \ .$$

Employing the Lagrangian method of optimization in the presence of a constraint, the revised, current period subproblem is

$$\text{Max} \quad \sum_{n=1}^{N+\Delta N} B_n(w_n) - C\left(\sum_{n=1}^{N+\Delta N} w_n, N, \Delta N\right) + \lambda \cdot \left((1-L)\cdot Z^* - \sum_{n=1}^{N+\Delta N} w_n\right) ,$$

where λ is the introduced Lagrange multiplier. When the constraint is binding, λ is positive, and it connotes the marginal value of raw water in the community. Following the prior procedure to develop an efficient water price, we obtain

$$p^* = \frac{\partial C}{\partial W} + \lambda . \qquad [14]$$

That is, it is easily demonstrated that price should include λ, the MVW. Though not an accounting cost for the utility, λ is an opportunity cost. Failure to include it in water price detracts from net benefits in the watershed. Failure to include it must either lead to inefficient nonprice rationing in the community (thereby lowering net benefits for the utility's consumers) or lead to overallocations of water to the utility vis-à-vis the watershed's other water users (lowering net

benefits for the region). To avoid double counting, any raw water costs appearing as accounting costs in C(W,N,ΔN) must be dropped from C before applying the pricing rule given by [14].

As a consequence of the revised water pricing rule [14], the utility receives revenue that is unmatched by accounting costs. Hence, the billing threshold must be increased in order to maintain a balanced budget, but the adjustment to [13] is easily made. Similar adjustments are necessitated by the incorporation of all NOCs.

Operationalizing the pricing rule indicated by [14] does not always require solution of the constrained subproblem. In regions where evidence for MVW is available, this value need only be converted into the proper units. For example, if permanent surface water rights are presently trading at $\$1/m^3$, and the real rate of discount (excluding inflation) is 4%, then $3.85¢/m^3$ is the implied value of raw water for the present period ($\$1 \bullet (0.04/(1+0.04))$). This procedure assumes a constant value for raw water in all periods, thereby overvaluing MVW in periods of plenty and undervaluing it in times of drought. If short-term (rental) water market values are observable and market participation is robust, then these values will be a preferred alternative.

Marginal User Cost

In the prior section we considered the value of raw water that arises when its use involves a sacrifice to alternative uses. In situations relating to unrenewed ground water supplies, water use causes a sacrifice in alternative *future* uses. That is, when scarce ground water is used now, those units of water will be unavailable for future use, begetting another type of NOC. The technical name for this opportunity cost is marginal user cost, defined as the value of sacrificed future uses, discounted to present value (Tietenberg 2000, p. 90). Moncur and Pollack (1988) simply refer to these opportunity costs as a "scarcity rent" in their investigation of its magnitude for a specific setting. To obtain the proper pricing rule, the optimization problem [1] must be augmented by linking future water costs to water usage in the present period, thereby making the problem dynamic.

We have already determined that it is optimal to price water so that everyone faces the same rates, so we can omit client-specific aspects of the optimization model and aggregate all benefits into the terms $B^t(W^t)$. To acknowledge that the utility's pumping costs are affected by water table elevation or, loosely, hydraulic head in the pumping period, H^t, the cost functions are revised to $C^t(W^t,N^t,\Delta N^t,H^t)$. [Again, we have no immediate interest in affecting N or ΔN beyond period 0.] Higher head lowers pumping costs, so $\partial C^t/\partial H^t<0$. Pumping in the current period tends to lower the hydraulic head experienced in all future periods. Likewise, natural ground water recharge, R^t, increases the head. The dynamic connection between head in consecutive periods is given by

$$H^{t+1} = H^t + h(W^t; R^t) \quad \text{for all } t>0. \qquad [15]$$

where h is the head gain function translating pumping and recharge into changes in hydraulic head. The current period's hydraulic head is H^0. Successive substitutions of [15] result in

$$H^t = H^0 + \sum_{\tau=0}^{t-1} h(W^\tau;R^\tau) \quad \text{for all } t>0. \qquad [16]$$

Substitution of the refined cost function and [16] into [1] provides an optimization problem appropriate for utilities mining ground water:

$$\text{Max } PV(\underline{W}, \underline{N}, \underline{\Delta N}) = \sum_{t=0}^{T} \rho^t \left[B^t(W^t) - C^t\left(W^t,N^t,\Delta N^t,H^0 + \sum_{\tau=0}^{t-1} h(W^\tau;R^\tau) \right) \right] . \qquad [17]$$

Optimization results pertaining to the selection of N^0 and ΔN^0 are unaltered in [17]. The necessary condition for resolving water use in the immediate period is

$$\left[\frac{dB^0}{dW^0} - \frac{\partial C^0}{\partial W^0} \right] - \frac{\partial h}{\partial W^0} \sum_{t=1}^{T} \rho^t \frac{\partial C^t}{\partial H^t} = 0 .$$

Comparing this finding with [8], the optimal pricing rule is obtained:

$$p^* = \frac{\partial C^0}{\partial W^0} + \frac{\partial h}{\partial W^0} \sum_{t=1}^{T} \rho^t \frac{\partial C^t}{\partial H^t} . \qquad [18]$$

When [18] is contrasted to [9], it is seen that optimal pricing involves a new component – marginal user cost (MUC):

$$MUC = \frac{\partial h}{\partial W^0} \sum_{t=1}^{T} \rho^t \frac{\partial C^t}{\partial H^t} \quad . \qquad [19]$$

MUC is positive because both derivatives of [19] are negative. The most challenging element of this formula to operationalize is $\partial C^t/\partial H^t$, the impact of head changes on costs. In circumstances where present and future mining is slight because of the contributions of natural recharge, $\partial C^t/\partial H^t$ will be dominated by the energy costs of greater pumping lifts. If ground water mining is more severe, decreased head may periodically induce the utility to install new wells together with connecting infrastructure to offset lowered pumping capacities. In more extreme cases, the utility may need to bear the costs of switching to surface water as ground water is depleted. All of these investments become part of $\partial C^t/\partial H^t$ during the periods when pumping capacity or surface water sources are to be expanded.

Although the fixed costs of induced ground and surface water investments may easily dominate MUC in cases involving moderate to severe mining, it can be instructive to bound MUC by focusing on the energy elements of $\partial C^t/\partial H^t$. In general, modified head has a linear effect on pumping costs, implying that this aspect of $\partial C^t/\partial H^t$ is relatively constant across periods. Denote the energy cost implications of lowered head by $\partial C/\partial H$. Employing these assumptions, we obtain the following lower bound for MUC:

$$MUC \geq \frac{\partial h}{\partial W} \frac{\partial C}{\partial H} \sum_{t=1}^{T} \rho^t = \frac{\partial h}{\partial W} \frac{\partial C}{\partial H} \frac{\rho(\rho^T - 1)}{\rho - 1} \quad .$$

It is relatively simple to operationalize the latter expression. The first derivative on the right hand side can be estimated from general aquifer parameters. The value of the second derivative can be determined through statistical analysis of pumping records containing energy usage and water table elevation or through modeling of ground water physics. The result constitutes a minimum MUC, and the omitted values are possibly large, so there is strong motivation for both including the minimum MUC in price and striving for the additional information needed to achieve [18] more completely.

Marginal Capacity Cost

An interesting facet of water planning concerns capacity expansion. Here lie crucial decisions relating to the choice of new facilities as well as the timing and sizing of these facilities. Such decisions often have large cost implications for the utility, so their efficient resolution can be important. A noteworthy aspect of new investments in water supply capital is their lumpiness. That is, in many instances it is efficient to undertake projects of greater scale than that necessary to satisfy the current quantity of water demanded. Hence, utilities tend to expand in spurts. As system capacity becomes limiting, utilities undertake the next project. Upon project completion, excess capacity exists for accommodating more demand growth, but growth eventually consumes this capacity and the next project is engaged.

The economic view is that optimal project timing maximizes the present value of net benefits. This is a more demanding criterion than requiring projects to pass a cost-benefit test. Pursuit of this goal typically implies that it is not rational to build projects in advance of demand. Moreover, it is often economically efficient to not build projects when demand for their capacity is slight. Premature construction is costly due to the time value of money and capital depreciation. Following an efficient path for the timing of lumpy projects therefore means that there are periods during which water supply capacity is less than the quantity of water demanded. During such periods, there is a third NOC to contemplate – marginal capacity cost (MCC). The existence of this NOC can be demonstrated to have implications for efficient pricing.

Suppose that the value of the utility's existing capital is given by K^0. A "yield" function, denoted by Y(K), translates capital into available water supply. In future periods, the capital base will be enhanced by investments and decreased by depreciation. Let investment in period t, I^t, contribute to capital in period t+1, and suppose the rate of depreciation is constant over time and given by $1-\alpha$ where $0 \le \alpha < 1$. Hence,

$$K^t = \alpha K^{t-1} + I^{t-1} \quad \text{for all } t>0.$$

Successive substitutions of this expression result in

$$K^t = \alpha^t K^0 + \sum_{\tau=0}^{t-1} \alpha^\tau I^{t-1-\tau} \quad \text{for all } t>0 \qquad [20]$$

where only the superscripts to α are exponents. In all periods, water supply is constrained by capacity, so

$$W^t \le Y(K^t) \quad \text{for all } t\ge 0. \qquad [21]$$

When problem [1] is augmented by investment costs and constraints [20] and [21], the resulting Lagrangian is

$$\text{Max} \sum_{t=0}^{T} \rho^t \left[B^t(W^t) - C^t\left(W^t, N, \Delta N\right) - rI^t \right] + \sum_{t=0}^{T} \delta^t \left[Y\left(\alpha^t K^0 + \sum_{\tau=0}^{t-1} \alpha^\tau I^{t-1-\tau} \right) - W^t \right] \qquad [22]$$

where r is the price of investment and δ^t are the introduced Lagrange multipliers for the supply capacity constraints of each period. For periods during which water supply capacity is binding, $\delta^t > 0$. The revised efficiency problem [22] has no new implications for the selection or pricing of N or ΔN, so let us focus upon the immediate decisions W^0 and I^0. Differentiating with respect to these two variables and setting them equal to zero yields

$$\frac{dB^0}{dW^0} - \frac{\partial C^0}{\partial W^0} - \delta^0 = 0 \qquad [23]$$

and

$$-r + \sum_{t=1}^{T} \delta^t \frac{dY}{dK^t} \alpha^{t-1} = 0 \ . \qquad [24]$$

Equation [24] indicates the efficient level of investment for the current period. In concert with [8], equation [23] tells us how to price current water:

$$p^* = \frac{\partial C^0}{\partial W^0} + \delta^0 \ . \qquad [25]$$

Price should include δ^0 which is marginal capacity cost in the current period.

The effect of including MCC in price is to efficiently ration available capacity during capacity-constrained periods. If price omits MCC during these periods, the quantity demanded will exceed supply. Two inefficient consequences can then occur. First, the shortfall will have to be accommodated through some nonprice allocation policy, implying that the marginal value of

finished water will not be equivalent across all clients. Second, deficient pricing will create a prevailing opinion, among both clients and responsive utility managers, that projects should be initiated to rectify the perceived shortage. If such action is taken, the investment regime will be accelerated beyond an efficient pace (failing [24]), and the present value of net benefits will be decreased.

The problematic aspect of incorporating MCC in price is its changing level over time. As supply capacity becomes more constraining over time due to growth in demand, MCC increases, but upon completion of a supply-enhancing project, MCC commonly falls to zero and remains there until further demand growth eliminates the excess capacity (Turvey 1976). Hence, MCC rises and falls over time. Its incorporation in rates brings about a long-term cycling in rates which may be objectionable to customers. Recognition of this issue has led to the creation of smoothing substitutes for MCC (Mann, Saunders, and Warford 1980), with the acknowledgement that some sacrifice in economic efficiency is made whenever rates do not embed true MCC. Still, use of an MCC substitute in water pricing is a likely improvement over abandonment of the matter.

Whereas the MCC derived from problem [22] would appear difficult to obtain in light of the dynamic extent of the problem, the character of the solution illuminated by [23] and [24] reveals some separability between the optimal investment strategy and MCC. Current MCC can be observed without calculating optimal current and future investments. Since only current MCC should be part of current water price, there is no need to solve an elaborate problem to acquire the future δ^t@. Assuming that price is being established for the current period using [25] and that excess demand of an estimatible amount is anticipated in the absence of an MCC-inclusive price, we need only know demand elasticity in order to estimate a price increase sufficient to assuage the excess demand. This rate hike is MCC.

Collected Pricing Implications

The previous sections develop water pricing recommendations pertaining to three distinct NOCs. If all apply at the same time in an additive manner, the pricing advice would be to include

all three along with $\partial C^0 / \partial W^0$, but this is an unlikely scenario. The MVW pertains primarily to surface water sources, but it is also applicable to fully renewable ground water sources. In either case raw water must be socially scarce for the MVW to be nonzero. MUC arises from the future opportunity costs of present water consumption, so it is primarily relevant to mined ground water sources. Hence, the marginal value of raw water and marginal user cost tend to arise in different circumstances, depending on the raw water source. For utilities employing both renewable and nonrenewable water sources, economic efficiency dictates a blending that achieves equivalent marginal costs (inclusive of NOCs) or a scheduling that first employs sources having the lowest marginal costs (inclusive of NOCs). Considering all possibilities, the emerging price proposal is

$$p^* = \frac{\partial C^0}{\partial W^0} + MVW \quad \text{or} \quad p^* = \frac{\partial C^0}{\partial W^0} + MUC \qquad [26]$$

depending, respectively, on whether renewable or nonrenewable water resources are being employed at the margin, W^0. In the case of blending at the margin, the prices of [26] are equal. In hydrologic situations where surface water use lowers ground water recharge or where ground water use induces surface water flows into ground water bodies, MVW and MUC values become interdependent, but [26] still applies.

Whereas the MVW and MUC arise from opportunity costs relating to water sources, the MCC is the consequence of constrained capital, so the prices of [26] must be augmented by MCC to allocate water efficiently. Of course, if the MVW or MUC has been incorporated in price, water quantity demanded is moderated and the necessary MCC will be lower. The complete pricing recommendation is

$$p^* = \frac{\partial C^0}{\partial W^0} + MVW + MCC \quad \text{or} \quad p^* = \frac{\partial C^0}{\partial W^0} + MUC + MCC \ . \qquad [27]$$

Flawed Local Pricing Policy

One of the most noteworthy features of the NOCs just discussed is the accounting stance over which each is relevant. To the extent that each possesses a local accounting stance, one may

be confident that well informed local utility management will design efficient rates. But where these opportunity costs fall outside the utility's jurisdiction, local pricing policy may be suspect.

The MCC has to do with capital-constrained water supply. In many cases these limiting facilities will be controlled and owned by the utility, so the MCC calculated by the utility will be a correct one. Should the utility be receiving water supply from a water purveyor that serves as a wholesaler to the utility and other buyers, and should the facilities of this purveyor be the constraining ones, then the achievement of efficiency hinges upon the allocative policies of the water purveyor. If the purveyor establishes quotas for each of its clients as a means of partitioning its capacity, the buyer's own quota will be a sound basis for determining its specific MCC. Alternatively, the purveyor can compute an overall MCC and make this part of its wholesale price, but such purveyors commonly serve few clients. The paucity of buyers will likely confuse the application of this approach, because MCC payments generate a rent for the wholesaler. Assuming that the wholesaler is obliged to be nonprofit, this rent must be dispersed in a lump sum, efficiency-serving manner – a challenge for a wholesaler serving few buyers. However, assuming the wholesaler calculates MCC well and the wholesaler's buyers include this MCC in finished water prices for their customers using [27], economic efficiency is achievable.

The prospects for sound local pricing policy are weaker for the MVW and MUC. Ideally, the MVW should be the regional value of renewable water. In areas where water marketing is not robust, clues regarding the value of raw water may be hard to find. In such cases, utilities are unlikely to commission proper *regional* studies of raw water value so that they may enhance regional efficiency by improving local pricing. Often, the efficiency gains of improved pricing lie substantially exterior to the utility or its customers. For example, by virture of history or aggressive planning, some utilities in water scarce regions possess water entitlements in excess of current demand quantities even when MVW is omitted from price. For such utilities, the adoption of MVW-inclusive pricing will lower quantity demanded, potentially revealing substantial excess supply. Such a surplus may dismay customers, who may have footed the bill for this

accumulation and are now being asked to pay MVW, and it may persuade other water users in the region to undertake political or legal actions to expropriate the exposed water surplus.

Thus, depending on circumstances and institutions, the prime beneficiaries of MVW-inclusive pricing may be external to some utilities, and such pricing may be locally regarded as unattractive. Of course, if water marketing is effective in the region, these problems may be circumvented through mutually beneficial trades, but water marketing is not yet practiced in many jurisdictions.

The remaining NOC, marginal user cost, was demonstrated earlier to be based upon the future costs consequent to current water consumption. Thus, it pertains primarily to nonrenewable ground water. As shown by [19], the pivotal elements of MUC are the future costs of lowered hydraulic head. Unless the utility is the sole user of the aquifer – an unlikely situation, some of the costs of lowered head fall to other pumpers. Hence, the normal circumstance is that a local accounting stance for assessing MUC would cause MUC to be undervalued. In the extreme, the utility may be a minor pumper of the aquifer in which case a locally computed MUC might drastically underestimate the social MUC. At the heart of this issue is the common property nature of ground water and the importance of collective action for achieving economic efficiency in mining ground water.

Overall, the extrajurisdictional elements of these NOCs suggest that local pricing policy will not achieve economically efficient resource allocations. This problem implies a need for well crafted policies to guide all utilities in their development of water tariffs. Many such policies are conceivable, but the most obvious is for state or national authorities to formulate, update, and require specific MVW and MUC amounts pertaining to each major watershed and aquifer. If this approach is taken, NOCs can be collected at the local level and dispersed across clients employing an appropriately revised bill threshold (equation [13]), thus raising the role of this instrument.

Conclusions

When the goal of water pricing is elevated from mere cost recovery to deriving the greatest value from water and associated nonwater resources, conventional rate regimes are found to be deficient. This is important, because revenue neutrality need not be sacrificed to achieve economic efficiency. A simple billing system is demonstrated to be both efficient and revenue neutral, providing that its parameters are purposefully chosen. Other efficient billing systems may also exist, and the economic theory assembled here serves as a benchmark for gauging alternative rate proposals.

It is noteworthy that revenue neutrality can be achieved by a simple and practical device, the billing threshold ($\overline{w}$), thereby allowing abandonment of wasteful average-cost pricing considering only accounting costs. The effect of $\overline{w}$ is to take the financial surpluses or deficits of water supply that are experienced by the utility and assign them equally across connections. The result is efficient, and it is arguably equitable. In addition, low-income households can utilize the threshold to their advantage.

From the perspective of this investigation, it is redundant to seek rates that advance water conservation. Because reduced water employment must be accompanied by reduced profits, reduced consumer satisfaction, and/or the substitution of other valuable resources for water, economically efficient water use embeds the proper degree of water conservation. Contemporary calls for water conservation in public policy are artifacts of deficient pricing schemes. Conventional rates encourage inefficient levels of water use because they omit important social values pertaining to water scarcity. This scarcity originates from intersectoral competition (MVW), depletion (MUC), and limited infrastructure (MCC). Once these values are reflected in rates and once marginal cost pricing is adopted, the need to advance water conservation vanishes. Moreover, nonprice conservation policy is likely to be a poor substitute for proper pricing, in the sense that it is price guides that most easily induce consumers to maximize the value derived from water.

Whereas it is demonstrated that water price should include applicable nonaccounting opportunity costs, it is also found that these costs are not fully borne by the utility and its clients. Hence, even if utilities choose to rely on a pricing doctrine that attends to NOCs, their own accounting stances may cause the NOCs to be understated. In some cases, this issue is likely to be serious, and state or federal policy regarding pricing practices may be a necessary remedy. Alternatively, water markets have some capability to address this issue by allowing transactions that signal surface water or ground water scarcity. Indeed, pricing and marketing policy appear to be complementary institutions insofar as the efficiency of water markets, which are fueled by excess water demand and excess water supply, is dependent on the establishment of efficient rates. Where rates are wrong, marketing will be misled.

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PACIFIC GAS AND ELECTRIC COMPANY
General Rate Case 2011 Phase II
Application 10-03-014
Data Response

PG&E Data Request No.:	AECA_002-22		
PG&E File Name:	GRC2011-Ph-II_DR_AECA_002-Q22		
Request Date:	September 8, 2010	Requester DR No.:	002
Date Sent:	September 24, 2010	Requesting Party:	AECA
PG&E Witness:	Keith Coyne	Requester:	Dan Geis

QUESTION 22

Please explain how current and proposed TOU rates offered by PG&E are compliant with California Public Utilities Code § 744.

ANSWER 22

California Public Utilities Code § 744 consists of two main requirements: (1) to offer interruptible rates to agricultural customers, and (2) to provide time-of-use (TOU) rates that offer a discount below system average electric rates but meet or exceed the cost to furnish service.

Although PG&E provided an agricultural interruptible option in the late 1980's, this option was discontinued upon a showing by PG&E in its 1991 Rate Design Window proceeding that the rate was not cost-effective. As a result, in D.91-04-062 the CPUC approved program termination pursuant to the Section 744 (b) requirement that interruptible rates be "economically feasible."

For TOU rate options, Section 744 (c) requires that such rate options "shall not be less than the cost of furnishing this service." PG&E has for over 20 years provided a large selection of optional TOU rates to agricultural customers. To PG&E's knowledge, the CPUC has not explicitly reviewed these agricultural TOU rate options with respect to compliance with Section 744 (c). In addition, PG&E is not aware that the Commission has evaluated the meaning of the "discount from system average rate" or "cost of furnishing service" phrases in Section 744, as this statute may be subject to interpretation.

PACIFIC GAS AND ELECTRIC COMPANY
2014 General Rate Case Phase II
Application 13-04-012
Data Response

PG&E Data Request No.:	AECA_001-31		
PG&E File Name:	GRC2014-Ph-II_DR_AECA_001-Q31		
Request Date:	May 24, 2013	Requester DR No.:	001
Date Sent:	July 8, 2013	Requesting Party:	Agricultural Energy Consumers Association
PG&E Witness:	Patricia Gideon	Requester:	Ann Trowbridge

QUESTION 31

Please provide the typical hourly load profile/shape used by PG&E in conducting marginal cost analysis and rate design, by rate class and/or schedule. Please provide this in the temporal disaggregation used by PG&E (e.g., summer/winter or monthly).

ANSWER 31 CERTAIN OF THE ATTACHMENTS CONTAIN CONFIDENTIAL INFORMATION

As described in Exhibit PG&E-1, Revenue Allocation and Rate Design, PG&E allocates revenue requirements, and to some extent, designs rates, based on marginal cost revenue. To develop marginal cost revenue, PG&E used peak capacity allocation factor (PCAF) and final line transformer (FLT) loads averaged across a 3-year period from 2009 through 2011. In the attached Excel files, PG&E provides the underlying yearly load data for the 3-year period from 2009 through 2011. Please note that PG&E measures loads on the half-hour. Therefore, each file contains 17,520 data points. Schedule E-37 is included with the "Agricultural: B Schedules". Years are represented as individual tabs within each file.

- GRC2014-Ph-II_DR_AECA_001-Q31-Atch01.xls – Residential Class
- GRC2014-Ph-II_DR_AECA_001-Q31-Atch02.xls – A1
- GRC2014-Ph-II_DR_AECA_001-Q31-Atch03.xls – A10
- GRC2014-Ph-II_DR_AECA_001-Q31-Atch04.xls – E19
-
- GRC2014-Ph-II_DR_AECA_001-Q31-Atch05.xls – E20 Primary
- GRC2014-Ph-II_DR_AECA_001-Q31-Atch06.xls – E20 Secondary
- GRC2014-Ph-II_DR_AECA_001-Q31-Atch07.xls – E20 Transmission
- GRC2014-Ph-II_DR_AECA_001-Q31-Atch08.xls – Standby Small C&I
- GRC2014-Ph-II_DR_AECA_001-Q31-Atch09.xls – Standby Med C&I
- GRC2014-Ph-II_DR_AECA_001-Q31-Atch10.xls – Standby E19
-
- GRC2014-Ph-II_DR_AECA_001-Q31-Atch11.xls – Standby E20
-

- GRC2014-Ph-II_DR_AECA_001-Q31-Atch12.xls – Agricultural: A Schedules
- GRC2014-Ph-II_DR_AECA_001-Q31-Atch13.xls – Agricultural: B Schedules

UF IFAS Extension UNIVERSITY of FLORIDA

BUL290

Evaporation Loss During Sprinkler Irrigation[1]

Fedro S. Zazueta[2]

Introduction

Both agricultural crops and landscapes are extensively irrigated in Florida, and sprinkler irrigation is widely used for both types of plants. In 1992, approximately 625,000 acres of commercial agricultural crops in Florida were irrigated with sprinklers. This figure represents almost 31 percent of Florida's 2,033,000 irrigated crop acres. In addition, sprinklers are used to irrigate approximately 1 million acres of turf and landscape, including golf courses, commercial landscapes, and home lawns.

Method of Water Distribution

When irrigation is applied by the sprinkler method, water is distributed over the irrigated area by spraying it through the air. Nozzles may be rotated to cover circular or part-circle land areas, or they may be fixed and equipped with deflectors that break up the water stream and deflect it onto the area to be irrigated. High uniformity of water application is achieved by overlapping the spray patterns from adjacent sprinklers.

During sprinkler operation, a stream of water is discharged into the air at high velocity. Friction between the air and the water stream causes the stream to break apart into water droplets that fall to the surface, similar to rainfall. When there is no wind, the sizes of droplets and their distribution patterns primarily depend on the nozzle design and any associated stream breakup mechanisms, the sprinkler's operating pressure, and the height of the sprinkler above the ground surface. Under windy conditions, wind speed and direction also affect droplet sizes and distribution patterns.

Evaporation from Sprinklers

During sprinkler operation, water evaporates from droplets sprayed through the air. The amount of evaporation depends on three factors: (1) the climate demand; (2) the time available for evaporation to occur; and (3) the surface area of the water droplets.

Climate Demand

The climate demand is a measure of the energy available for evaporation and the capacity of the air to store and transmit water vapor. The evaporation process requires 580 calories of energy to convert 1 gram of water from the liquid to the vapor form. This energy must be available from the environment surrounding the sprinkler. Energy is readily available during summer months, as indicated by high air temperatures and high levels of solar radiation. Conversely, low temperatures and low levels of solar radiation during winter months provide less energy for evaporation.

Air humidity is often expressed as relative humidity, which ranges from near 0 to 100 percent, with low values indicating dry air and high values indicating moist air. Since dry air has a greater capacity for moisture, evaporation will occur more rapidly when the air is dry than when it is moist. When the relative humidity is 100 percent, the air is saturated at its current temperature and cannot hold more water; thus, no further evaporation occurs. This condition exists after dewfall at night, during foggy conditions, and

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during rainfall. Also, since humidity levels are normally high during early morning and early evening hours in humid areas such as Florida, evaporation rates are low during these times on most days.

Wind increases evaporation rates by transporting water vapor away from the evaporating surface. Wind also increases evaporation by transporting warmer or drier air from surrounding areas to displace the moist, cool air above an irrigated surface.

Time Available for Evaporation to Occur

The time available for evaporation to occur is the relatively short time beginning when a water droplet leaves the nozzle and ending when it falls on the ground or vegetated surface. When water is sprayed at greater heights and over greater distances, this opportunity time for evaporation is increased. Thus, more evaporation would be expected to occur from a sprinkler installed on a tall riser than from the same sprinkler (operated at the same pressure so that the drop size distribution is the same) installed on a short riser.

Wind speeds are faster at greater heights above the ground surface, where there are few obstacles to air movement. Thus, evaporation loss from sprinklers mounted on tall risers is also increased because of these higher wind speeds.

Surface Area of Water Droplets

Because evaporation occurs from the surface of the water droplets, the total surface area of the water droplets greatly affects the amount of evaporation loss. For a unit volume of water, the surface area doubles as the droplet diameter decreases by half. For this reason, evaporation rate increases as droplet size decreases if other factors remain constant, and the factors that cause droplet size to decrease will cause evaporation loss to increase.

Wind Drift Loss

Wind drift loss occurs when wind carries water droplets away from the irrigated area. Droplets may either evaporate while they are being transported or may fall outside the irrigated area. In either case, the water is lost because it is not available to the plants being irrigated.

Wind drift loss increases as wind speeds increase and as droplet sizes decrease. At higher wind speeds, larger droplets can be transported by the wind, and droplets can be transported greater distances.

Estimating Sprinkler Evaporation Loss

Many studies of evaporation loss during sprinkler irrigation have been conducted, and some are listed as references to this publication. The most extensive early work was done by Frost and Schwalen (1955, 1960) in Arizona. In their 1960 article, Frost and Schwalen summarized the results of 700 field tests conducted under a variety of climate conditions. They developed a nomograph that enables the user to estimate the percentage of evaporation loss during sprinkler irrigation as a function of sprinkler characteristics, operating pressure, and climate factors. They concluded that evaporation loss could be accurately estimated using three climate factors: air temperature, relative humidity, and wind speed.

The Frost and Schwalen nomograph has been widely used to estimate sprinkler evaporation loss. It has been published in several irrigation textbooks (Pair et al., 1983; Schwab et al., 1981).

Seginer (1971) found strong correlations between sprinkler evaporation loss in Israel and both solar radiation and air temperature. He found weaker correlations with relative humidity and wind speed. He concluded that evaporation loss due to wind drift was negligible for the 3 to 4 mph wind speed conditions of his study.

Myers et al. (1970) conducted wind tunnel tests of sprinkler evaporation loss for typical Florida climate conditions. They stated it is unlikely that evaporation from water droplets in transit from the sprinkler to the ground or plant surface could represent more than 5 percent of the water applied by typical sprinkler irrigation systems under Florida climate conditions.

Evaporation Nomograph

The Frost and Schwalen (1960) nomograph can be used to estimate evaporation loss for specific climate and operating conditions. This nomograph allows the user to estimate the amount of evaporation loss for different times of day or for daytime and nighttime irrigation.

The Frost and Schwalen nomograph is shown in Figure 1. It consists of vertical columns numbered 1 through 9. Data must be entered in columns 1, 2, 5, 7, and 9. The nomograph is used by drawing straight lines that connect the input data to calculate intermediate factors in columns 3, 4, and 8. Finally, a straight line is drawn between columns 4 and 8 to provide an estimate of the percentage of

evaporation loss in column 6. The use of the nomograph is illustrated by the following example: Estimate the percentage of evaporation loss from a sprinkler with a 3/16-inch nozzle diameter operated at 40 pounds per square inch (psi) when wind speed is 5 miles per hour (mph), temperature is 90°F, and relative humidity is 10 percent. The sprinkler discharge rate in this example is 6.3 gallons per minute (gpm).

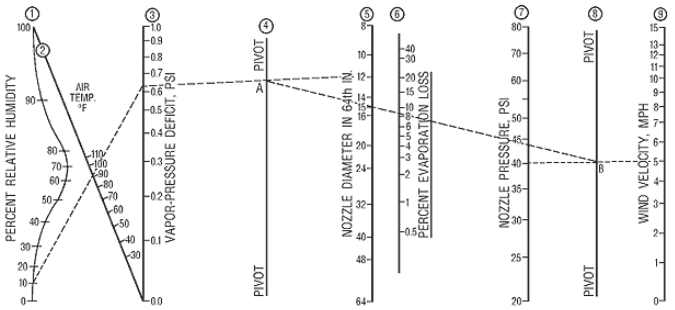


Figure 1. Sprinkler evaporation nomograph (from Frost and Schwalen, 1955).

This example represents very extreme climate conditions for a humid area such as Florida. In most cases, the relative humidity would be much higher than 10 percent. Therefore, the normal amount of sprinkler evaporation loss in Florida would be expected to be much smaller than that calculated in this example.

The solution is illustrated by the broken lines in Figure 1. The calculations are done in the following steps:

1. Draw a straight line from the point representing 10 percent relative humidity in column 1 through the mark for 90°F temperature in column. Extend this line to indicate a vapor-pressure deficit of 0.63 psi in column 3.

2. Draw a straight line from the point representing 0.63 psi vapor-pressure deficit in column 3 to the mark that indicates 3/16-inch (12/64-inch) nozzle diameter in column 5. Locate point A where this line intersects the pivot line in column 4. Point A will be used in step 4 below.

3. Draw a straight line from the mark for 40 psi nozzle pressure in column 7 to the point representing 5 mph wind speed in column 9. Locate point B where this line intersects the pivot line in column 8. Point B will be used in step 4 below.

4. Draw a straight line from point A on the pivot line in column 4 to point B on the pivot line in column 8. Read the percentage of evaporation loss where this line intersects column 6. For this example, evaporation loss is 8.5 percent.

Thus, 8.5 percent of the water discharged from an irrigation system using 3/16-inch nozzle diameters and operating at 40 psi would evaporate under these extreme climate conditions. Under typical Florida climate conditions, evaporation loss would not be expected to exceed this value. For the 6.3 gpm sprinkler discharge rate, 8.5 percent, or 0.54 gpm, would be expected to evaporate, while the remaining 5.76 gpm would be expected to reach the soil surface or plant canopy.

Sprinkler Evaporation Loss in Florida

Despite typical high temperatures, there is relatively little sprinkler evaporation loss in Florida because of high humidity levels and low wind speeds. As an example, long-term average climate data for Gainesville, Florida are listed in Table 1 (Whitty et al., 1992).

Long-term daily maximum, average, and minimum daily temperatures are shown for each month and as annual averages. Daily average temperatures range from 56°F in winter to 81°F in summer. Daily maximum temperatures range from 68°F in winter to 92°F in summer. Table 1 also lists long-term minimum and average daily relative humidity values for each month. Maximum values (not shown) are near 100 percent for each month. Relative humidity values do not change greatly throughout the year. Minimum relative humidity values range from 40 percent in April to 53 percent in August. Average relativehumidity values range from 70 percent in April to 77 percent in August.

Long-term daily and daytime average wind speeds also are listed in Table 1. Daytime averages are shown because most evaporation takes place during daylight hours, when wind speeds and temperatures are highest and relative humidity values are lowest. Daytime wind speeds were estimated as being 1.3 times the daily (24-hour) average values. In Gainesville, wind speeds are highest (3.2 mph) during February and March and lowest (1.6 mph) in August.

The combined effects of temperature and relative humidity determine the vapor pressure deficit. The vapor pressure deficit is a measure of the dryness of the air; thus, it is an index of the evaporation rate. Figure 2 shows the general relationships among air temperature, relative humidity, and vapor pressure deficit from the Frost and Schwalen (1960) nomograph. This figure illustrates that the vapor pressure deficit (and evaporation rate) will be highest when temperatures are high and the relative humidity is low. Notice that when temperatures are low, the vapor pressure deficit will be low, despite the humidity level. Also, when

the relative humidity is high, the vapor pressure deficit will be low, despite the temperature.

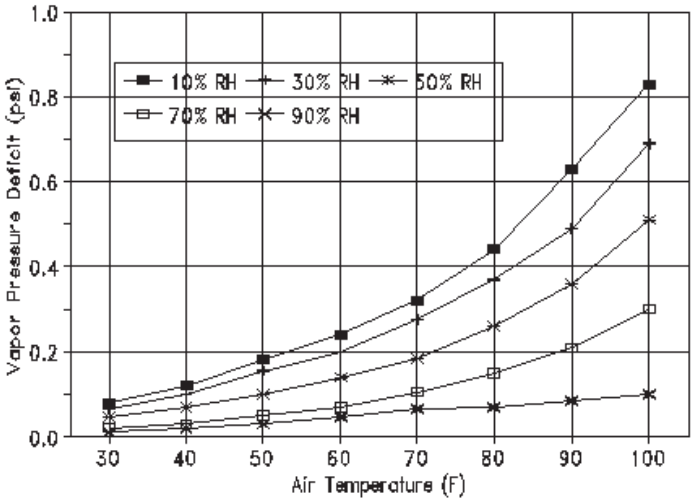


Figure 2. Air vapor pressure deficit as a function of temperature and relative humidity.

Because high humidity levels are typical in Florida, the vapor pressure deficit is typically low despite the high temperatures. Figure 3 shows monthly vapor pressure deficits for Gainesville. These were calculated from the temperature and relative humidity data in Table 1 using the Frost and Schwalen nomograph (Figure 1). Both maximum and average monthly values were calculated. The maximum values were calculated from the maximum temperature and minimum relative humidity data. These values would be expected to represent peak vapor pressure deficits occurring during the early afternoon, when temperatures are highest and humidities are lowest. The average values were calculated from average temperatures and average relative humidity readings. These values would be expected to represent average daily vapor pressure deficits, the average of both daytime and nighttime conditions.

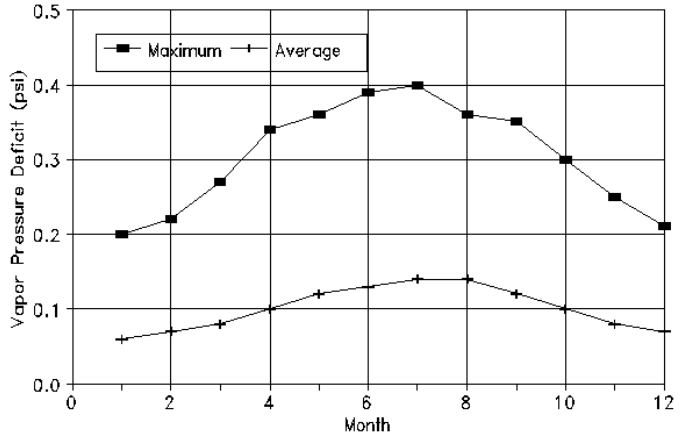


Figure 3. Long-term maximum and average monthly vapor pressures at Gainesville, FL.

In Gainesville, average daily vapor pressure deficits are low, ranging from 0.06 psi in January to 0.14 psi in July and August. Maximum daily vapor pressure deficits are larger and more variable, ranging from 0.2 psi in January to 0.4 psi in July.

Monthly evaporation percentages for Gainesville were calculated using the vapor pressure deficit data from Figure 3 and the wind speed data from Table 1. A mid-range sprinkler nozzle diameter (5/16-inch) and a mid-range pressure (45 psi) were assumed. Figure 4 shows the monthly distribution of average and maximum daily evaporation percentages. The average daily values were low and uniform at about 1.5 percent throughout the year. The maximum (early afternoon) values were more variable, ranging from 2.1 percent in January and December to 3.1 percent in July.

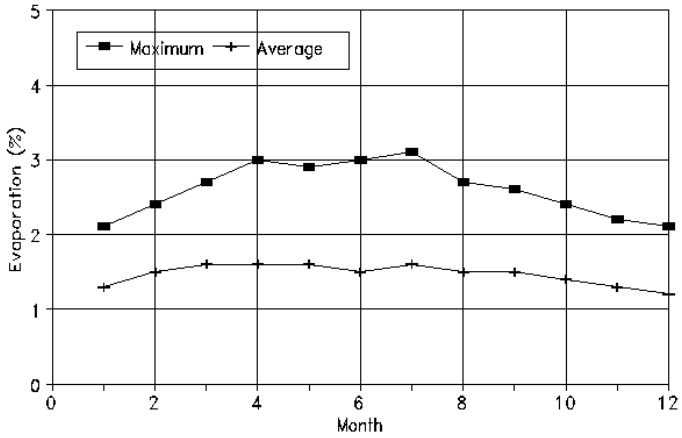


Figure 4. Maximum and average evaporation percentages for a 5/16-inch sprinkler nozzle diameter and operating pressure of 45 psi at Gainesville, FL.

Reducing Evaporation Loss from Sprinklers

Evaporation loss from a sprinkler irrigation system can be reduced by changing the sprinkler operating conditions to increase the sizes of water droplets or by irrigating when climate demands are low.

Evaporation loss will be reduced by changing either or both of the following operating conditions: (1) increasing the nozzle diameter, or (2) decreasing the operating pressure. Both of these changes will increase the proportion of large droplets, thus decreasing the surface area from which evaporation can occur. However, sprinkler users must follow the manufacturer's recommendations when selecting nozzle diameters and operating pressures. Otherwise, poor distribution patterns will occur, reducing the uniformity of water application.

The effect of changing the nozzle diameter is illustrated in Figure 5. Calculations for this example were made using Gainesville climate data for June and sprinklers operated at 45 psi. As shown in Figure 5, the evaporation percentage is large when small nozzles are used. It is small when large nozzles are used and other factors remain constant. Notice that the evaporation percentage is not linearly related to the nozzle diameter. It increases rapidly when nozzle sizes are decreased below 5/16-inch but decreases slowly when nozzle sizes are increased.

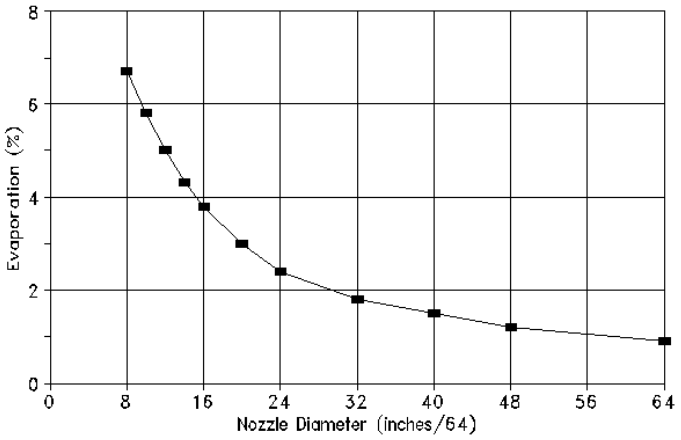


Figure 5. Sensitivity of evaporation percentage to changes in sprinkler nozzle diameter for an operating pressure of 45 psi and June climate data at Gainesville, FL.

The effect of changing the operating pressure is shown in Figure 6. Calculations for this example were made using Gainesville climate data for June and 5/16-inch nozzle diameters. As Figure 6 illustrates, the evaporation percentage is small when small pressures are used; it is large when large pressures are used and other factors remain constant. Also, the relationship between evaporation percentage and pressure is approximately linear. It increased from 1.4 percent at 20 psi to 5 percent at 80 psi.

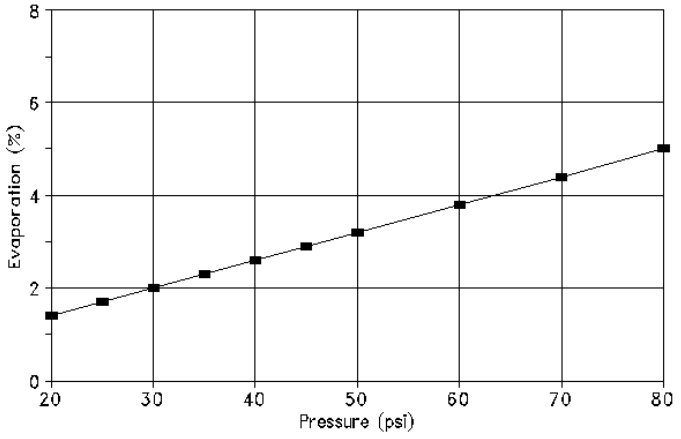


Figure 6. Sensitivity of evaporation percentage to changes in sprinkler operating pressure for a 5/16-inch nozzle diameter and June climate data at Gainesville, FL.

The use of excessively large nozzles or excessively small pressures must be avoided. Excessively large nozzles will increase sprinkler and distribution pipeline flow rates, making the system cost too high. Also, soil infiltration rates may be exceeded, causing runoff. Thus, allowable increases in nozzle sizes will be limited by economic considerations and production system characteristics.

Excessively low pressures will reduce the uniformity of water application and waste water because of low application efficiencies. Sprinkler mechanisms will not operate properly at pressures that are too low. Excessively low pressures also will produce droplet sizes that are too large, creating the potential for crop damage or soil erosion from the impact of the droplets. Thus, allowable reductions in pressures will be limited by sprinkler operating characteristics and the requirement for uniform water applications.

Evaporation loss can be reduced by operating sprinklers only when climate demand is low. This means operating sprinklers when relative humidity is high and air temperature and wind speed are low. In Florida, the relative humidity is very high during nighttime, early morning, and late evening hours on most days. At those times, air temperatures are also low and wind speeds are normally reduced, minimizing sprinkler evaporation loss. Figure 7 illustrates the effects of wind speed on evaporation loss, using Gainesville climate data for June, sprinklers with 5/16-inch nozzle diameters, and operating pressures of 45 psi. For this example, the relationship between evaporation percentage and wind speed ranging from 0 to 15 mph was approximately linear. Evaporation loss increased from 2.1 percent to 8.0 percent as wind speed increased from 0 to 15 mph.

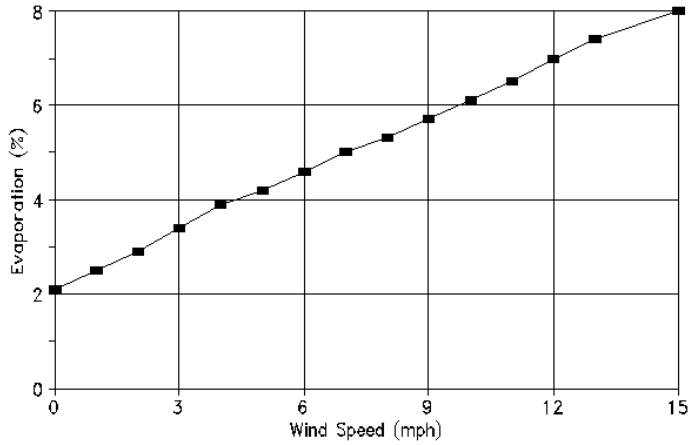


Figure 7. Sensitivity of evaporation percentage to changes in wind speed for a 5/16-inch nozzle diameter, 45 psi, and June climate data at Gainesville, FL.

Reducing Wind Drift Loss

Wind drift loss occurs when small water droplets are transported from the irrigated area by wind. This occurs when droplets are small and wind speed is high.

If the wind is blowing when irrigation occurs, some wind drift loss is unavoidable. To avoid excessive wind drift loss, irrigation systems should not be operated when wind speeds are high. Also, a sprinkler should be operated only within the operating pressure range for which it was designed. If operating pressures are too high, too many small droplets will be created and wind drift loss will increase. Most sprinkler companies manufacture nozzles specifically designed to reduce the number of small droplets and minimize wind drift loss.

Increasing Evaporation Loss from Sprinklers

Under some conditions, it may be desirable to increase the amount of evaporation loss from sprinklers. Such increases would be desirable when sprinklers are being used for crop cooling, as is the case during the establishment of transplants, or when water disposal is the objective -- for example, in the design of sprayfields for land applications of wastewater.

Evaporation from sprinklers cools plant and ground surfaces and the surrounding air. Thus, sprinkler irrigation is used to prevent excessive water stress while plant roots (normally, those of young plants or transplants) are developing. It is often required to establish such fruits and vegetables as strawberries and cabbage, and many ornamental plants.

In the design of sprayfields for wastewater disposal, the size of the required sprayfield can be reduced if evaporation loss is increased. Such reductions are possible because some of the water discharged from sprinklers evaporates before it reaches the ground or plant surface.

To increase evaporation loss, small nozzles should be used and sprinklers operated at high pressures and when climate demand is greatest. Climate demand will normally be greatest during the early afternoon, when relative humidity is lowest and air temperature and wind speed are highest.

Excessively high operating pressures should be avoided because both diameter of coverage and water application uniformity will be reduced if the pressure is too high. Also, sprinkler mechanisms may not operate properly at excessively high pressures.

Under windy conditions, the distribution of the very small water droplets created by excessive pressures will be easily distorted by wind. These small droplets may be transported to surrounding areas by wind drift. Under calm conditions, these small droplets will fall nearer the sprinkler, reducing the effective diameter of coverage and possibly reducing the uniformity of water application. Thus, the maximum operating pressure should be limited based on the sprinkler manufacturer's recommendations so that acceptable diameters of coverage and uniformity of water application may be achieved.

Summary

During sprinkler operation, some evaporation occurs from water droplets as they are sprayed through the air. The amount of evaporation depends on (1) the climate demand; (2) the time available for evaporation to occur; and (3) the surface area of the droplets. A nomograph for estimating evaporation loss from sprinklers was presented. For climate conditions typical of Gainesville, Florida, the average daily evaporation loss would be expected to be about 1.5 percent. The average loss would be expected to be about 3 percent for sprinkler operation during early afternoon hours on typical summer days. The amount of loss would be very small for operation during nighttime, early morning, and early evening hours.

Sprinkler evaporation loss can be reduced by changing sprinkler operating conditions to increase water droplet size or by operating the system under conditions of low climate demand. Climate demand is low at night and during early morning and early evening hours.

Evaporation loss can be increased by using small nozzles and operating sprinklers at high pressures to produce small water droplets, and by operating systems when climate demand is greatest. Climate demand will normally be greatest during the early afternoon, when relative humidity is lowest and air temperature and wind speed are highest. Sprinklers should not be operated outside the manufacturer's recommended pressure range because they may perform poorly under such conditions.

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Table 1. Long-term average climate data for Gainesville, FL.

Month	Temperature			Wind Speed		Rel. Humidity	
	Max.°F	Min.°F	Avg.°F	Avg. mi/hr	Daytime mi/hr	Min.%	Avg.%
1	68.6	43.5	56.1	2.08	2.71	47	73
2	70.5	44.9	57.7	2.46	3.20	45	72
3	76.7	51.0	63.8	2.46	3.20	42	71
4	82.4	55.8	69.1	2.21	2.87	40	70
5	87.9	62.8	75.4	1.79	2.33	43	71
6	90.7	69.3	80.0	1.58	2.06	49	74
7	91.6	71.0	81.3	1.58	2.06	49	74
8	91.5	71.2	81.3	1.21	1.57	53	76
9	89.1	69.6	79.3	1.42	1.84	52	76
10	82.7	60.4	71.6	1.75	2.28	49	74
11	75.6	52.0	63.8	1.75	2.28	48	74
12	70.0	46.1	58.1	1.83	2.38	48	74
Avg.	81.4	58.1	69.8	1.84	2.40	47.1	73.5

STATE WATER RESOURCES CONTROL BOARD
RESOLUTION NO. 2015-0032

TO ADOPT AN EMERGENCY REGULATION FOR
STATEWIDE URBAN WATER CONSERVATION

WHEREAS:

1. On April 25, 2014, Governor Edmund G. Brown Jr. issued an executive order (April 2014 Proclamation) to strengthen the State's ability to manage water and habitat effectively in drought conditions, and called on all Californians to redouble their efforts to conserve water. The April 2014 Proclamation finds that the continuous severe drought conditions present urgent challenges across the State, including water shortages in communities and for agricultural production, increased wildfires, degraded habitat for fish and wildlife, threat of saltwater contamination, and additional water scarcity, if drought conditions continue into 2015. The April 2014 Proclamation also suspends the environmental review required by the California Environmental Quality Act to allow the emergency regulation and other actions to take place as quickly as possible;

2. The April 2014 Proclamation refers to the Governor's Proclamation No. 1-17-2014, issued on January 17, 2014, declaring a drought State of Emergency to exist in California due to severe drought conditions (January 2014 Proclamation). The January 2014 Proclamation finds that dry conditions and lack of precipitation present urgent problems to drinking water supplies and cultivation of crops, which put farmers' long-term investments at risk. The conditions also threaten the survival of animals and plants that rely on California's rivers, including many species in danger of extinction. The January 2014 Proclamation also calls on all Californians to reduce their water usage by 20 percent;

3. On December 22, 2014, in light of the continued lack of rain, Governor Brown issued Executive Order B-28-14, which extends the California Environmental Quality Act suspension through May 31, 2016 for Water Code section 13247 and certain activities identified in the January 2014 and April 2014 proclamations;

4. On April 1, 2015, Governor Brown issued a new Executive Order that directs the State Water Board to impose restrictions on urban water suppliers to achieve a statewide 25 percent reduction in potable urban usage through February 2016; require commercial, industrial, and institutional users to implement water efficiency measures; prohibit irrigation with potable water of ornamental turf in public street medians; and prohibit irrigation with potable water outside newly constructed homes and buildings that is not delivered by drip or microspray systems; along with other directives;

5. Water Code section 1058.5 grants the State Water Board the authority to adopt emergency regulations in certain drought years in order to: "prevent the waste, unreasonable use, unreasonable method of use, or unreasonable method of diversion, of water, to promote water recycling or water conservation, to require curtailment of diversions when water is not available under the diverter's priority of right, or in furtherance of any of the foregoing, to require reporting of diversion or use or the preparation of monitoring reports";

6. On July 15, 2014, the State Water Board adopted an emergency regulation to support water conservation (Resolution No. 2014-0038), and that regulation became effective July 28, 2014 upon approval by the Office of Administrative Law (OAL);

7. On March 17, 2015, the State Water Board amended and readopted the emergency regulation to support water conservation (Resolution No. 2015-0013), which became effective March 27, 2015 upon approval by OAL;

8. The current emergency regulation has supported Californians' water conservation efforts, with over 125 billion gallons saved from August 2014 through March 2015; however, statewide water use is only nine percent less than the same months in 2013. Achieving a 25 percent reduction in use will require even greater conservation efforts across the state. In particular, many communities must dramatically reduce their outdoor water use;

9. In many areas, 50 percent or more of daily water use is for lawns and outdoor landscaping. Outdoor water use is generally discretionary, and many irrigated landscapes will survive while receiving a decreased amount of water;

10. Although urban water suppliers have placed restrictions on outdoor watering, the State Water Board continues to receive reports of excessive outdoor water use;

11. Water conservation is the easiest, most efficient and most cost-effective way to quickly reduce water demand and extend supplies into the next year, providing flexibility for all California communities. Water saved this summer is water available later in the season or next year, reducing the likelihood of even more severe water shortages should the drought continue;

12. Education and enforcement against water waste is a key tool in conservation programs. When conservation becomes a social norm in a community, the need for enforcement is reduced or eliminated;

13. Public information and awareness is critical to achieving conservation goals, and the Save Our Water campaign, run jointly by the Department of Water Resources (DWR) and the Association of California Water Agencies, is an excellent resource for conservation information and messaging that is integral to effective drought response (http://saveourwater.com);

14. Many California communities are facing social and economic hardship due to this drought. The rest of us can make adjustments to our water use, including landscape choices that conserve even more water;

15. The California Constitution declares, at article X, section 2, that the water resources of the state must be put to beneficial use in a manner that is reasonable and not wasteful. Relevant to the current drought conditions, the California Supreme Court has clarified that "what may be a reasonable beneficial use, where water is present in excess of all needs, would not be a reasonable beneficial use in an area of great scarcity and great need. What is a beneficial use at one time may, because of changed conditions, become a waste of water at a later time." (*Tulare Dist. v. Lindsay Strathmore Dist*. (1935) 3 Cal.2d 489, 567.) In support of water conservation, the legislature has, through Water Code section 1011, deemed reductions in water use due to conservation as equivalent

to reasonable beneficial use of that water. Accordingly, this regulation is in furtherance of article X, section 2 during this drought emergency. This temporary emergency regulation is not to be used in any future administrative or judicial proceedings as evidence or finding of waste and unreasonable use of any individual water user or water supplier subject to this regulation, and are not to affect or otherwise limit any rights to water conserved under applicable law, including without limitation, water conserved consistent with Water Code section 1011;

16. Directive two of the Governor's April 1, 2015 Executive Order directs the State Water Board to consider the relative per capita usage of each urban water supplier's service area and require that areas with high per capita use achieve proportionally greater reductions than areas with low per capita use;

17. On April 7, 2015, the State Water Board issued a draft framework proposing increasing levels of required water reduction based upon residential per capita per day use (R-GPCD) for the proposed regulation, and solicited public comments. The Board received over 300 comments on the framework, primarily relating to the levels of required water reduction;

18. On April 18, the State Water Board issued draft regulatory language for public comment based on the April 7 framework and the comments received. The draft regulatory language reflected careful consideration of all comments including those directed at the levels of required reduction. Again, the Board received close to 300 comments;

19. On April 28, 2015, the State Water Board issued a final version of draft regulatory language for comment, followed on April 29 by a formal public notice that it would consider the adoption of the emergency regulation at the Board's regularly-scheduled May 5 and 6, 2015 public meeting, in accordance with applicable State laws and regulations. The State Water Board also distributed for public review and comment a Finding of Emergency that complies with State laws and regulations;

20. As discussed above, the State Water Board is adopting the emergency regulation because of the continuing emergency drought conditions, the need for prompt action to prevent the waste and unreasonable use of water and to promote conservation, and the specific actions called for in the Governor's April 1, 2015 Executive Order; and

21. Nothing in the regulation or in the enforcement provisions of the regulation precludes a local agency from exercising its authority to adopt more stringent conservation measures. Moreover, the Water Code does not impose a mandatory penalty for violations of the regulation adopted by this resolution, and local agencies retain the enforcement discretion in enforcing the regulation to the extent authorized. Local agencies are encouraged to develop their own progressive enforcement practices to promote conservation.

THEREFORE BE IT RESOLVED THAT:

1. The State Water Board adopts California Code of Regulations, title 23, section 866 and re-adopts sections 863, 864,and 865, as appended to this resolution as an emergency regulation;

2. State Water Board staff will submit the regulation to OAL for final approval;

3. If, during the approval process, State Water Board staff, the State Water Board, or OAL determines that minor corrections to the language of the regulation or supporting documentation are needed for clarity or consistency, the State Water Board Executive Director or the Executive Director's designee may make such changes;

4. This regulation shall remain in effect for 270 days after filing with the Secretary of State unless the State Water Board determines that it is no longer necessary due to changed conditions, or unless the State Water Board renews the regulation due to continued drought conditions as described in Water Code section 1058.5;

5. The State Water Board directs staff to provide the Board with monthly updates on the implementation of the emergency regulation and its effect. These updates shall include information regarding the progress of the Building Standards Commission, Department of Housing and Community Development, and other state agencies in the adoption and implementation of emergency regulations or other requirements that implement increased outdoor irrigation efficiency for new construction. These regulations and other requirements will extend existing efficiency standards for new construction to the outdoor environment and ensure that California's new homes are constructed to meet the growing demand with the most efficient standards;

6. The State Water Board directs staff to condition funding upon compliance with the emergency regulation, to the extent feasible;

7. The State Water Board directs staff to work with DWR and the Save Our Water campaign to disseminate information regarding the emergency regulation; and

8. The State Water Board directs staff to update the electronic reporting portal to include data fields for the new reporting required by the emergency regulation.

THEREFORE BE IT FURTHER RESOLVED THAT:

9. The State Water Board shall work with DWR, the Public Utilities Commission, and other agencies to support urban water suppliers' actions to implement rates and pricing structures to incent additional conservation, as required by directive eight in the Governor's April 1, 2015 Executive Order. The Fourth District Court of Appeal's recent Decision in *Capistrano Taxpayer Association Inc. v. City of San Juan Capistrano* (G048969) does not foreclose the use of conservation-oriented rate structures;

10. The State Water Board calls upon water suppliers to:

    a. ensure that adequate personnel and financial resources exist to implement conservation requirements not only for 2015, but also for another year of drought should it occur. Water suppliers that face budget shortfalls due to reduced sales should take immediate steps to raise necessary revenues in a way that actively promotes continued conservation;

    b. expedite implementation of new conservation programs by minimizing internal review periods and utilizing emergency authorities, as appropriate;

c. consider the relative water use and conservation practices of their customers and target those with higher water use to achieve proportionally greater reductions than those with low use;

d. minimize financial impacts to low-income customers;

e. preserve safe indoor water supplies in areas with very low R-GPCD and where necessary to protect public health and safety;

f. promote low-water use methods of preserving appropriate defensible space in fire-prone areas, consistent with local fire district requirements;

g. educate customers on the preservation of trees;

h. promote on-site reuse of water; and

i. promptly notify staff of the supplier's need for an alternate method of compliance pursuant to resolved paragraph 16.

11. The State Water Board calls upon all businesses within California's travel and tourism sectors to inform visitors of California's dire drought situation and actions visitors should take to conserve water;

12. The State Water Board commends wholesale water agencies that have set aggressive conservation targets for their retail water suppliers;

13. The State Water Board commends water suppliers that have made investments to boost drought-resistant supplies, such as advanced treated recycled water and desalination. Those investments help to make communities more resilient in the face of drought;

14. The State Water Board commends the many water suppliers that have already surpassed their 20x2020 conservation targets. Long-term conservation efforts are critical to maintaining economic and social well-being, especially in light of the impacts of climate change on California's hydrology;

15. During this drought emergency, heightened conservation that extends urban resilience is necessary. The State Water Board's focus is primarily on immediate reductions in outdoor water use. Some short-term conservation efforts, such as landscape conversions and installation of efficient appliances, will also support long-term conservation objectives, and are encouraged wherever possible;

16. The State Water Board recognizes that some commercial and industrial customers, while accounting for a significant portion of total use in a service area, have already taken steps to significantly reduce their water consumption and cannot further reduce their use without substantial impacts. However, the Board also recognizes that in many areas there are significant opportunities for reductions in water use by industries and commercial enterprises that have yet to take action, especially those with large areas of non-functional turf. The Board directs staff to respond promptly upon receipt of any request for alternate enforceable methods of compliance. If the supplier believes the conservation standard is unachievable due to firm commercial and industrial water use

and residential use reductions that would affect public health and safety, it should provide any supporting information or documentation for an alternate method of compliance; and

17. Some water suppliers have called for further refinement of the tiers to reflect a range of factors that contribute to water use, including but not limited to temperature, lot size, and income. Others have called for an approach that provides greater recognition for early investments in conservation, the development of local, drought resistant water supplies, and health and safety needs. These suggestions and many others are important considerations in the development of a more comprehensive, and long term, conservation framework. The State Water Board directs staff to work with stakeholders on a thoughtful process to devise options for extended and expanded emergency regulations should the drought continue into 2016.

CERTIFICATION

The undersigned Clerk to the Board does hereby certify that the foregoing is a full, true, and correct copy of a resolution duly and regularly adopted at a meeting of the State Water Resources Control Board held on May 5, 2015.

AYE:	Chair Felicia Marcus Vice Chair Frances Spivy-Weber Board Member Tam M. Doduc Board Member Steven Moore Board Member Dorene D'Adamo
NAY:	None
ABSENT:	None
ABSTAIN:	None

Jeanine Townsend

Jeanine Townsend
Clerk to the Board

ADOPTED TEXT OF EMERGENCY REGULATION

Article 22.5. Drought Emergency Water Conservation.

Sec. 863. Findings of Drought Emergency.

(a) The State Water Resources Control Board finds as follows:

(1) On January 17, 2014, the Governor issued a proclamation of a state of emergency under the California Emergency Services Act based on drought conditions;

(2) On April 25, 2014, the Governor issued a proclamation of a continued state of emergency under the California Emergency Services Act based on continued drought conditions;

(3) On April 1, 2015, the Governor issued an Executive Order that, in part, directs the State Board to impose restrictions on water suppliers to achieve a statewide 25 percent reduction in potable urban usage through February, 2016; require commercial, industrial, and institutional users to implement water efficiency measures; prohibit irrigation with potable water of ornamental turf in public street medians; and prohibit irrigation with potable water outside newly constructed homes and buildings that is not delivered by drip or microspray systems;

(4) The drought conditions that formed the basis of the Governor's emergency proclamations continue to exist;

(5) The present year is critically dry and has been immediately preceded by two or more consecutive below normal, dry, or critically dry years; and

(6) The drought conditions will likely continue for the foreseeable future and additional action by both the State Water Resources Control Board and local water suppliers will likely be necessary to prevent waste and unreasonable use of water and to further promote conservation.

Authority: Section 1058.5, Water Code.
References: Cal. Const., Art., X § 2; Sections 102, 104, 105, and 275, Water Code; *Light v. State Water Resources Control Board* (2014) 226 Cal.App.4th 1463.

Sec. 864. End-User Requirements in Promotion of Water Conservation.

(a) To prevent the waste and unreasonable use of water and to promote water conservation, each of the following actions is prohibited, except where necessary to address an immediate health and safety need or to comply with a term or condition in a permit issued by a state or federal agency:

(1) The application of potable water to outdoor landscapes in a manner that causes runoff such that water flows onto adjacent property, non-irrigated areas, private and public walkways, roadways, parking lots, or structures;

(2) The use of a hose that dispenses potable water to wash a motor vehicle, except where the hose is fitted with a shut-off nozzle or device attached to it that causes it to cease dispensing water immediately when not in use;

(3) The application of potable water to driveways and sidewalks; and

(4) The use of potable water in a fountain or other decorative water feature, except where the water is part of a recirculating system;

(5) The application of potable water to outdoor landscapes during and within 48 hours after measurable rainfall;

(6) The serving of drinking water other than upon request in eating or drinking establishments, including but not limited to restaurants, hotels, cafes, cafeterias, bars, or other public places where food or drink are served and/or purchased;

(7) The irrigation with potable water of ornamental turf on public street medians; and

(8) The irrigation with potable water of landscapes outside of newly constructed homes and buildings in a manner inconsistent with regulations or other requirements established by the California Building Standards Commission and the Department of Housing and Community Development.

(b) To promote water conservation, operators of hotels and motels shall provide guests with the option of choosing not to have towels and linens laundered daily. The hotel or motel shall prominently display notice of this option in each guestroom using clear and easily understood language.

(c) Immediately upon this subdivision taking effect, all commercial, industrial and institutional properties that use a water supply, any portion of which is from a source other than a water supplier subject to section 865, shall either:

(1) Limit outdoor irrigation of ornamental landscapes or turf with potable water to no more than two days per week; or

(2) Reduce potable water usage supplied by sources other than a water supplier by 25 percent for the months of June 2015 through February 2016 as compared to the amount used from those sources for the same months in 2013.

(d) The taking of any action prohibited in subdivision (a) or the failure to take any action required in subdivisions (b) or (c), is an infraction, punishable by a fine of up to five hundred dollars ($500) for each day in which the violation occurs. The fine for the infraction is in addition to, and does not supersede or limit, any other remedies, civil or criminal.

Authority: Section 1058.5, Water Code.
References: Cal. Const., Art., X § 2; Sections 102, 104, 105, 275, 350, and 10617, Water Code; *Light v. State Water Resources Control Board* (2014) 226 Cal.App.4th 1463.

Sec. 865. Mandatory Actions by Water Suppliers.

(a) As used in this section:

(1) "Distributor of a public water supply" has the same meaning as under section 350 of the Water Code, except it does not refer to such distributors when they are functioning solely in a wholesale capacity, but does apply to distributors when they are functioning in a retail capacity.

(2) "R-GPCD" means residential gallons per capita per day.

(3) "Total potable water production" means all potable water that enters into a water supplier's distribution system, excluding water placed into storage and not withdrawn for use during the reporting period, or water exported outsider the supplier's service area.

(4) "Urban water supplier" means a supplier that meets the definition set forth in Water Code section 10617, except it does not refer to suppliers when they are functioning solely in a wholesale capacity, but does apply to suppliers when they are functioning in a retail capacity.

(b) In furtherance of the promotion of water conservation each urban water supplier shall:

(1) Provide prompt notice to a customer whenever the supplier obtains information that indicates that a leak may exist within the end-user's exclusive control.

(2) Prepare and submit to the State Water Resources Control Board by the 15th of each month a monitoring report on forms provided by the Board. The monitoring report shall include the amount of potable water the urban water supplier produced, including water provided by a wholesaler, in the preceding calendar month and shall compare that amount to the amount produced in the same calendar month in 2013. The monitoring report shall specify the population served by the urban water supplier, the percentage of water produced that is used for the residential sector, descriptive statistics on water conservation compliance and enforcement efforts, and the number of days that outdoor irrigation is allowed, and monthly commercial, industrial and institutional sector use. The monitoring report shall also estimate the gallons of water per person per day used by the residential customers it serves.

(c)(1) To prevent the waste and unreasonable use of water and to meet the requirements of the Governor's April 1, 2015 Executive Order, each urban water supplier shall reduce its total potable water production by the percentage identified as its conservation standard in this subdivision. Each urban water supplier's conservation standard considers its service area's relative per capita water usage.

(2) Each urban water supplier whose source of supply does not include groundwater or water imported from outside the hydrologic region in which the water supplier is located, and that has a minimum of four years' reserved supply available may, submit to the Executive Director for approval a request that, in lieu of the reduction that would otherwise be required under paragraphs (3) through (10), the urban water supplier shall reduce its total potable water production by 4 percent for each month as compared to the amount used in the same month in 2013. Any such request shall be accompanied by information showing that the supplier's sources of supply do not include groundwater or water imported from outside the hydrologic region and that the supplier has a minimum of four years' reserved supply available.

(3) Each urban water supplier whose average July-September 2014 R-GPCD was less than 65 shall reduce its total potable water production by 8 percent for each month as compared to the amount used in the same month in 2013.

(4) Each urban water supplier whose average July-September 2014 R-GPCD was 65 or more but less than 80 shall reduce its total potable water production by 12 percent for each month as compared to the amount used in the same month in 2013.

(5) Each urban water supplier whose average July-September 2014 R-GPCD was 80 or more but less than 95 shall reduce its total potable water production by 16 percent for each month as compared to the amount used in the same month in 2013.

(6) Each urban water supplier whose average July-September 2014 R-GPCD was 95 or more but less than 110 shall reduce its total potable water production by 20 percent for each month as compared to the amount used in the same month in 2013.

(7) Each urban water supplier whose average July-September 2014 R-GPCD was 110 or more but less than 130 shall reduce its total potable water production by 24 percent for each month as compared to the amount used in the same month in 2013.

(8) Each urban water supplier whose average July-September 2014 R-GPCD was 130 or more but less than 170 shall reduce its total potable water production by 28 percent for each month as compared to the amount used in the same month in 2013.

(9) Each urban water supplier whose average July-September 2014 R-GPCD was 170 or more but less than 215 shall reduce its total potable water production by 32 percent for each month as compared to the amount used in the same month in 2013.

(10) Each urban water supplier whose average July-September 2014 R-GPCD was 215 or more shall reduce its total potable water production by 36 percent for each month as compared to the amount used in the same month in 2013.

(d)(1) Beginning June 1, 2015, each urban water supplier shall comply with the conservation standard specified in subdivision (c).

(2) Compliance with the requirements of this subdivision shall be measured monthly and assessed on a cumulative basis.

(e)(1) Each urban water supplier that provides potable water for commercial agricultural use meeting the definition of Government Code section 51201, subdivision (b), may subtract the amount of water provided for commercial agricultural use from its potable water production total, provided that any urban water supplier that subtracts any water provided for commercial agricultural use from its total potable water production shall:

(A) Impose reductions determined locally appropriate by the urban water supplier, after considering the applicable urban water supplier conservation standard specified in subdivision (c), for commercial agricultural users meeting the definition of Government Code section 51201, subdivision (b) served by the supplier;

(B) Report its total potable water production pursuant to subdivision (b)(2) of this section, the total amount of water supplied for commercial agricultural use, and shall identify the reduction imposed on its commercial agricultural users and each recipient of potable water for commercial agricultural use;

(C) Certify that the agricultural uses it serves meet the definition of Government Code section 51201, subdivision (b); and

(D) Comply with the Agricultural Water Management Plan requirement of paragraph 12 of the April 1, 2015 Executive Order for all commercial agricultural water served by the supplier that is subtracted from its total potable water production.

(2) Submitting any information pursuant to subdivision (e)(1)(B) or (C) of this section that is found to be materially false by the board is a violation of this regulation, punishable by civil liability of up to five hundred dollars ($500) for each day in which the violation occurs. Every day that the error goes uncorrected constitutes a separate violation. Civil liability for the violation is in addition to, and does not supersede or limit, any other remedies, civil or criminal.

(f)(1) To prevent waste and unreasonable use of water and to promote water conservation, each distributor of a public water supply that is not an urban water supplier shall take one or more of the following actions:

(A) Limit outdoor irrigation of ornamental landscapes or turf with potable water by the persons it serves to no more than two days per week; or

(B) Reduce by 25 percent reduction its total potable water production relative to the amount produced in 2013.

(2) Each distributor of a public water supply that is not an urban water supplier shall submit a report by December 15, 2015, on a form provided by the Board, that either confirms compliance with subdivision (f)(1)(A) or identifies total potable water production, by month, from June through November, 2015, and total potable water production, by month, for June through November 2013.

Authority: Section 1058.5, Water Code.
References: Cal. Const., Art., X § 2; Sections 102, 104, 105, 275, 350, 1846, 10617 and 10632, Water Code; *Light v. State Water Resources Control Board* (2014) 226 Cal.App.4th 1463.

Sec. 866. Additional Conservation Tools.

(a)(1) To prevent the waste and unreasonable use of water and to promote conservation, when a water supplier does not meet its conservation standard required by section 865 the Executive Director, or the Executive Director's designee, may issue conservation orders requiring additional actions by the supplier to come into compliance with its conservation standard.

(2) A decision or order issued under this article by the board or an officer or employee of the board is subject to reconsideration under article 2 (commencing with section 1122) of chapter 4 of part 1 of division 2 of the California Water Code.

(b) The Executive Director, or his designee, may issue an informational order requiring water suppliers, or commercial, industrial or institutional properties that receive any portion of their supply from a source other than a water supplier subject to section 865, to submit additional information relating to water production, water use or water conservation. The failure to provide the information requested within 30 days or any additional time extension granted is a violation subject to civil liability of up to $500 per day for each day the violation continues pursuant to Water Code section 1846.

Authority: Section 1058.5, Water Code.
References: Cal. Const., Art., X § 2; Sections 100, 102, 104, 105, 174, 186, 187, 275, 350, 1051, 1122, 1123, 1825, 1846, 10617 and 10632, Water Code; *Light v. State Water Resources Control Board* (2014) 226 Cal.App.4th 1463.

Schedule TOU-PA-3-RTP Sheet 1
AGRICULTURAL AND PUMPING - LARGE
TIME OF USE - REAL TIME PRICING

APPLICABILITY

Applicable to Bundled Service Customers where SCE determines that 70 percent or more of the Customer's electrical usage is for Agricultural Power Service, General Water or Sewerage Pumping, or for oil pumping by Customers with a Standard Industrial Classification (SIC) Code of 1311, and none of any remaining electrical usage is for purposes for which a domestic schedule is applicable. This Schedule is applicable to Customers whose monthly Maximum Demand registers, or in the opinion of SCE, is expected to register between 200 kW through 500 kW. This Schedule is not applicable when, in the opinion of SCE, the Customer's monthly Maximum Demand is expected to exceed 500 kW or has exceeded 500 kW for any three months during the preceding 12 months. Effective with the date of ineligibility, the Customer's account shall be transferred to Schedule TOU-8-RTP or Schedule TOU-8-RTP-S if the Customer's account is also served under Schedule S.

Customers with Maximum Demands exceeding 500 kW and who meet the criteria of the following exceptions are either ineligible or not required to take service under Schedules TOU-8, TOU-8-S, TOU-8-RTP, or TOU-8-RTP-S, and are eligible for service on an applicable agricultural and pumping rate schedule including this Schedule and Schedule S, if applicable:

1. Individual water agency accounts where 70 percent or more of the water pumped is used for Agricultural Power Service purposes and other water pumping accounts where 70 percent or more of the water pumped is used for Agricultural Power Service purposes who have signed Form 14-317, Declaration and Rate Election for Water Agencies and Water Pumping accounts. Such accounts are ineligible for service under Schedules TOU-8 or TOU-8-S; and

2. Customers who are (1) packing houses that pack only whole fruits or whole vegetables, and associated cold storage on the same Premises as the packing houses; (2) cotton gins; (3) nut hulling and shelling operations; or (4) producing unflavored fluid milk fit for human consumption by way of pasteurization, homogenization, vitaminization or fat standardization that have signed Form 14-927, Affidavit Regarding Eligibility for Agricultural Power Service. Such accounts are not required to take service under Schedules TOU-8 or TOU-8-S.

Further, any Customer served under this Schedule whose monthly Maximum Demand has registered below 200 kW for 12 consecutive months is ineligible for service under this Schedule and shall be transferred to Schedule TOU-PA-2-RTP. Except for interruptible Customers, a Customer who makes a permanent change in operating conditions that SCE, in its sole opinion, anticipates will reduce the Customer's demand to below 200 kW, may transfer to Schedule TOU-PA-2-RTP before completing 12 consecutive months at the reduced demand levels.

This Schedule is optional for Customers eligible for service under agricultural and pumping rate schedules. This Schedule is subject to meter availability. Customers served under this Schedule are not eligible for service under Schedules CPP, SLRP, and the Day-Ahead Option of CBP.

Pursuant to California Public Utilities Commission Decisions 18-07-006 and 18-11-027, Customers served on this Schedule prior to March 1, 2019 will be placed on Option D-RTP with updated TOU Periods on their next scheduled billing date following March 1, 2019.

(Continued)

Schedule TOU-PA-3-RTP — Sheet 2
AGRICULTURAL AND PUMPING - LARGE
TIME OF USE - REAL TIME PRICING
(Continued)

RATES (Continued)

		Delivery Service								Generation[9]	
		Trans[1]	Distrbtn[2]	NSGC[3]	NDC[4]	PPPC[5]	DWRBC[6]	PUCRF[7]	Total[8]	UG*	DWREC[10]
TOU-PA-3-D-RTP											
Energy Charge - $/kWh/Meter/Month											
	Summer Season - On-Peak	0.00343	0.02691 (I)	0.00662	(0.00050)	0.00891 (I)	0.00580	0.00130 (I)	0.05247 (I)	Variable**	(0.00007)
	Mid-Peak	0.00343	0.02691 (I)	0.00662	(0.00050)	0.00891 (I)	0.00580	0.00130 (I)	0.05247 (I)	Variable**	(0.00007)
	Off-Peak	0.00343	0.00569 (I)	0.00662	(0.00050)	0.00891 (I)	0.00580	0.00130 (I)	0.03125 (I)	Variable**	(0.00007)
	Winter Season - Mid-Peak	0.00343	0.01210 (I)	0.00662	(0.00050)	0.00891 (I)	0.00580	0.00130 (I)	0.03766 (I)	Variable**	(0.00007)
	Off-Peak	0.00343	0.01034 (I)	0.00662	(0.00050)	0.00891 (I)	0.00580	0.00130 (I)	0.03590 (I)	Variable**	(0.00007)
	Super-Off-Peak	0.00343	0.00703 (I)	0.00662	(0.00050)	0.00891 (I)	0.00580	0.00130 (I)	0.03259 (I)	Variable**	(0.00007)
			255.79 (I)						255.79 (I)		
Facilities Related											
Demand Charge - $/kW		2.29	7.50 (I)						9.79 (I)	0.00	
Time Related Demand Charge - $/kW											
	Summer Season - On-Peak		3.03 (I)						3.03 (I)	0.00	
Voltage Discount, Facilities Related Demand - $/kW											
	From 2 kV to 50 kV		(0.10) (I)						(0.10) (I)		
	Above 50 kV but below 220 kV		(4.01) (I)						(4.01) (I)		
	At 220 kV		(7.50) (I)						(7.50) (I)		
Voltage Discount, Time Related Demand - $/kW											
	From 2 kV to 50 kV		(0.05)						(0.05)	0.00	
	Above 50 kV but below 220 kV		(1.27) (I)						(1.27) (I)	0.00	
	At 220 kV		(3.03) (I)						(3.03) (I)	0.00	
Voltage Discount, Energy - $/kWh											
	From 2 kV to 50 kV	0.00000	(0.00012) (I)						(0.00012) (I)	(0.00119)	
	Above 50 kV but below 220 kV	0.00000	(0.00359) (I)						(0.00359) (I)	(0.00280)	
	At 220 kV	0.00000	(0.00857) (I)						(0.00857) (I)	(0.00282)	
Power Factor Adjustment - $/kVA											
	Greater than 50 kV		0.54						0.54		
	50 kV or less		0.60						0.60		

* The ongoing Competition Transition Charge (CTC) of $0.00063 per kWh is recovered in the UG component of Generation.
** Hourly rates are listed below and are applicable to service metered and delivered below 2 kV, 2 kV to 50 kV, and above 50 kV.
1 Trans = Transmission and the Transmission Owners Tariff Charge Adjustments (TOTCA) which are FERC approved. The TOTCA represents the Transmission Revenue Balancing Account Adjustment (TRBAA) of $(0.00076) per kWh, Reliability Services Balancing Account Adjustment (RSBAA) of $0.00000 per kWh, and Transmission Access Charge Balancing Account Adjustment (TACBAA) of $0.00419 per kWh.
2 Distrbtn = Distribution
3 NSGC = New System Generation Charge
4 NDC = Nuclear Decommissioning Charge
5 PPPC = Public Purpose Programs Charge (includes California Alternate Rates for Energy Surcharge where applicable.)
6 DWRBC = Department of Water Resources (DWR) Bond Charge. The DWR Bond Charge is the Wildfire Fund Non-Bypassable Charge which supports the California Wildfire Fund and is not applicable to exempt Customers pursuant to D.19-10-056. (T) (T)
7 PUCRF = The PUC Reimbursement Fee is described in Schedule RF-E.
8 Total = Total Delivery Service rates are applicable to Bundled Service Customers.
9 Generation = The Generation rates are applicable only to Bundled Service Customers.
10 DWREC = Department of Water Resources (DWR) Energy Credit – For more information on the DWR Energy Credit, see the Billing Calculation Special Condition of this Schedule.

(Continued)

Schedule TOU-PA-3-RTP Sheet 3
AGRICULTURAL AND PUMPING - LARGE
TIME OF USE - REAL TIME PRICING
(Continued)

RATES (Continued)

Hourly UG Rates[4]

TYPE OF DAY (WEEKDAY OR WEEKEND) AND APPLICABLE TEMPERATURE [2/]

TOU-PA-3-D-RTP

HOURLY URG RATE ($/kWh)

HOUR[2/] ENDING @ PST	HOT SUMMER WEEKDAY (>=91)	MODERATE SUMMER WEEKDAY (81-90)	MILD SUMMER WEEKDAY (<=80)	HIGH COST WINTER WEEKDAY (>90)	LOW COST WINTER WEEKDAY (<=90)	HIGH COST WEEKEND (>=78)	LOW COST WEEKEND (<78)
1 a.m.	0.04855 (I)	0.04884 (I)	0.04704 (I)	0.05118 (I)	0.04822 (I)	0.04862 (I)	0.04871 (I)
2 a.m.	0.04863 (I)	0.04874 (I)	0.04707 (I)	0.05074 (I)	0.04800 (I)	0.04882 (I)	0.04868 (I)
3 a.m.	0.04868 (I)	0.04902 (I)	0.04755 (I)	0.05043 (I)	0.04834 (I)	0.04898 (I)	0.04890 (I)
4 a.m.	0.04998 (I)	0.05037 (I)	0.04856 (I)	0.05113 (I)	0.04894 (I)	0.04945 (I)	0.04924 (I)
5 a.m.	0.05310 (I)	0.05361 (I)	0.05130 (I)	0.05241 (I)	0.05093 (I)	0.05051 (I)	0.05007 (I)
6 a.m.	0.05761 (I)	0.05684 (I)	0.05127 (I)	0.05649 (I)	0.05496 (I)	0.05102 (I)	0.05023 (I)
7 a.m.	0.04979 (I)	0.04955 (I)	0.04635 (I)	0.06183 (I)	0.05622 (I)	0.04863 (I)	0.04682 (I)
8 a.m.	0.04610 (I)	0.04638 (I)	0.04244 (I)	0.06049 (I)	0.05105 (I)	0.04081 (I)	0.03693 (I)
9 a.m.	0.04368 (I)	0.04436 (I)	0.03936 (I)	0.05063 (I)	0.04373 (I)	0.02748 (I)	0.02705 (I)
10 a.m.	0.04220 (I)	0.04399 (I)	0.03858 (I)	0.04819 (I)	0.03902 (I)	0.01918 (I)	0.01834 (I)
11 a.m.	0.04240 (I)	0.04476 (I)	0.03968 (I)	0.04660 (I)	0.03507 (I)	0.01579 (I)	0.01451 (I)
12 noon	0.04315 (I)	0.04574 (I)	0.03984 (I)	0.04515 (I)	0.03191 (I)	0.01471 (I)	0.01583 (I)
1 p.m.	0.04570 (I)	0.04774 (I)	0.04244 (I)	0.04439 (I)	0.03256 (I)	0.01624 (I)	0.01855 (I)
2 p.m.	0.05332 (I)	0.05332 (I)	0.04700 (I)	0.04457 (I)	0.03606 (I)	0.02253 (I)	0.02994 (I)
3 p.m.	0.05474 (I)	0.05466 (I)	0.04688 (I)	0.04515 (I)	0.04187 (I)	0.03116 (I)	0.04033 (I)
4 p.m.	0.05703 (I)	0.05599 (I)	0.04818 (I)	0.04953 (I)	0.04602 (I)	0.04440 (I)	0.04628 (I)
5 p.m.	0.08534 (I)	0.05888 (I)	0.05138 (I)	0.06091 (I)	0.05299 (I)	0.05099 (I)	0.05270 (I)
6 p.m.	3.14095 (I)	0.09671 (I)	0.05903 (I)	0.08326 (I)	0.06694 (I)	0.48823 (I)	0.06276 (I)
7 p.m.	3.02545 (I)	0.17001 (I)	0.07472 (I)	0.08357 (I)	0.07453 (I)	0.91147 (I)	0.06894 (I)
8 p.m.	0.75771 (I)	0.12313 (I)	0.07451 (I)	0.06881 (I)	0.06682 (I)	0.07966 (I)	0.06510 (I)
9 p.m.	0.07874 (I)	0.06715 (I)	0.06667 (I)	0.06376 (I)	0.06138 (I)	0.06116 (I)	0.05968 (I)
10 p.m.	0.05956 (I)	0.06191 (I)	0.06174 (I)	0.06275 (I)	0.05895 (I)	0.05808 (I)	0.05704 (I)
11 p.m.	0.05197 (I)	0.05313 (I)	0.05121 (I)	0.05987 (I)	0.05416 (I)	0.05265 (I)	0.05194 (I)
Midnight[3/]	0.05006 (I)	0.05065 (I)	0.04823 (I)	0.05444 (I)	0.04993 (I)	0.04993 (I)	0.04979 (I)

[1] The applicable temperature for each type of day is the prior day's Downtown Los Angeles site maximum temperature as recorded by the National Weather Service. In the event that data is unavailable from Downtown LA as the primary source, data collected by the National Weather Service from Long Beach Airport shall be used. Where data is not available from either site, SCE shall enact its procedure for emergency data collection in order to provide substitute temperature data. The seasons and holidays are set forth in the Special Conditions of the Schedule(s) referenced above.

[2/] During Pacific Standard Time, the applicable hour and corresponding rate is for the hour ENDING at the hour shown. During Daylight Saving Time, the applicable hour and corresponding rate is for the hour BEGINNING at the hour shown.

[3/] During Daylight Saving Time, the applicable rate for the hour beginning 12 midnight is the rate from the applicable day/temperature column in effect on the PRIOR day for the hour beginning 12 midnight.
Transition to and from Daylight Saving Time: When Daylight Saving Time begins, the applicable hour skips from 2 a.m. to 3 a.m. and the rate is the rate applicable to the hour beginning at 3 a.m. Similarly, when Pacific Standard Time resumes, the time changes from 2 a.m. back to 1 a.m. and the rate for the beginning of Pacific Standard Time is the rate for the hour ending 2 a.m.
Note: In the transition to Daylight Saving Time an hour is lost, while in the transition to Pacific Standard Time, an hour is gained.

[4/] The ongoing Competition Transition Charge (CTC) of $0.00063 per kWh is recovered in Generation. (I)

(Continued)

Schedule TOU-PA-3-RTP Sheet 4 (T)
AGRICULTURAL AND PUMPING - LARGE
TIME OF USE - REAL TIME PRICING
(Continued)

SPECIAL CONDITIONS

1. Applicable rate time periods are defined as follows:

TOU Period	Weekdays		Weekends and Holidays	
	Summer	Winter	Summer	Winter
On-Peak	4 p.m. - 9 p.m.	N/A	N/A	N/A
Mid-Peak	N/A	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.
Off-Peak	All other hours	9 p.m. - 8 a.m.	All other hours	9 p.m. - 8 a.m.
Super-Off-Peak	N/A	8 a.m. - 4 p.m.	N/A	8 a.m. - 4 p.m.

The Summer Season shall commence at 12:00 a.m. on June 1 and continue until 12:00 a.m. on October 1 of each year. The Winter Season shall commence at 12:00 a.m. on October 1 of each year and continue until 12:00 a.m. on June 1 of the following year.

Holidays are New Year's Day (January 1), Presidents' Day (third Monday in February), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Veterans Day (November 11), Thanksgiving Day (fourth Thursday in November), and Christmas (December 25).

When any holiday listed above falls on Sunday, the High Cost or Low Cost Weekend Pricing, indicated in the Hourly Generation Rate table, will apply the following Monday. When any holiday listed above falls on a weekday, then High Cost or Low Cost Weekend Pricing will apply. No change will be made for holidays falling on Saturday.

2. Agreements:

   a. Individual water agency accounts with demand levels greater than 500 kW where 70 percent or more of the water pumped is used for Agricultural Power Service purposes, and other water pumping accounts with demands above 500 kW where 70 percent or more of the water pumped is used for Agricultural Power Service purposes must sign a Declaration and Rate Election for Water Agencies and Water Pumping Accounts, Form 14-317, to qualify for this Schedule.

   b. Customers who are (1) packing houses that pack only whole fruits or whole vegetables, and associated cold storage on the same Premises as the packing houses; (2) cotton gins; (3) nut hulling and shelling operations; or (4) producing unflavored fluid milk fit for human consumption by way of pasteurization, homogenization, vitaminization or fat standardization must sign an Affidavit Regarding Eligibility for Agricultural Power Service, Form 14-927, to qualify for this Schedule.

   c. Excluding individual water agency accounts, Customers taking service under this Schedule for General Water or Sewerage Pumping must sign an Affidavit Regarding Eligibility for General Water and Sewerage Pumping Service, Form 14-946, to qualify for this Schedule.

(Continued)

Schedule TOU-PA-3-RTP Sheet 5 (T)
AGRICULTURAL AND PUMPING - LARGE
TIME OF USE - REAL TIME PRICING
(Continued)

SPECIAL CONDITIONS (Continued)

3. Voltage: Service will be supplied at one standard voltage.

4. Temporary Discontinuance of Service: Where the use of energy is seasonal or intermittent, no adjustments will be made for a temporary discontinuance of service. Any Customer prior to resuming service within twelve months after such service was discontinued will be required to pay all charges which would have been billed if service had not been discontinued.

5. Maximum Demand: Maximum Demand for the billing month shall be established for all applicable TOU Periods. The Maximum Demand for each TOU Period shall be the measured maximum average kilowatt (kW) input indicated or recorded by instruments, during any 15-minute metered interval in that billing month. Where the demand is intermittent or subject to violent fluctuations, a 5-minute interval may be used.

6. Billing Demand: The Billing Demand shall be the kW kilowatts of Maximum Demand determined to the nearest kW. When applicable, the Time-Related Demand (TRD) component shall be for the kW of Maximum Demand recorded (or established for) each of the TOU Periods, as applicable according to the Customers Rate Option. The Facilities Related Demand (FRD) component shall be for the kW of Maximum Demand recorded during (or established for) the monthly billing period. However, when SCE determines the Customer's meter will record little or no energy use for extended periods of time or when the Customer's meter has not recorded a Maximum Demand in the preceding eleven months, the Facilities Related Component of the Demand Charge may be established at 50 percent of the Customer's connected load.

7. Real Time Pricing: As used in this Schedule, Real Time Pricing is the practice of continuously varying prices to Customers to reflect simulated hourly variations in the marginal costs of generating electricity.

8. Marginal Cost: As used in this Schedule, Marginal Cost is the change in the total cost of the generation of an additional kilowatt hour of electricity.

9. Voltage Discount: Bundled Service Customers will have the Distribution rate component of the applicable Delivery Service reduced by the corresponding Voltage Discount amount for service metered and delivered at the applicable voltage level as shown in the Rates section above. In addition, Bundled Service Customers will have the applicable Generation, Transmission, and Distribution charges reduced by the corresponding Voltage Discount amount for service metered and delivered at the applicable voltage level as shown in the Rates section.

(Continued)

Schedule TOU-PA-3-RTP Sheet 6 (T)
AGRICULTURAL AND PUMPING - LARGE
TIME OF USE - REAL TIME PRICING
(Continued)

SPECIAL CONDITIONS (Continued)

10. Power Factor Adjustment: The Customer's bill will be increased each month for power factor by the amount shown in the Rates section above for service metered and delivered at the applicable voltage level, based on the per kilovar of maximum reactive demand imposed by SCE.

    The maximum reactive demand shall be the highest measured maximum average kilovar demand indicated or recorded by metering during any 15 minute metered interval in the month. The kilovars shall be determined to the nearest unit. A device will be installed on each kilovar meter to prevent reverse operation of the meter.

11. The daily maximum temperature, as recorded by the National Weather Service, at its Downtown Los Angeles site, will be used to determine the hourly rates for the following day according to the this Schedule. It is the responsibility of the Customers to acquire the daily maximum temperature at the Downtown Los Angeles site. SCE is not required to provide the daily maximum temperature. In the event that data is unavailable from Downtown LA as the primary source, data collected by the National Weather Service from Long Beach Airport shall be used. Where data is not available from either site, SCE shall enact its procedure for emergency data collection in order to provide substitute temperature data.

12. Customer-Owned Electrical Generating Facilities:

    a. Where Customer-owned electrical generating facilities are used to meet a part or all of the Customer's electrical requirements, service shall be provided concurrently under the terms and conditions of Schedule S and this Schedule. Parallel operation of such generating facilities with SCE's electrical system is permitted. A generation interconnection agreement is required for such operation.

    b. Customer-owned electrical generating facilities used solely for auxiliary, emergency, or standby purposes (auxiliary/emergency generating facilities) to serve the Customer's load during a period when SCE's service is unavailable and when such load is isolated from the service of SCE are not subject to Schedule S. However, upon approval by SCE, momentary parallel operation may be permitted to allow the Customer to test the auxiliary/emergency generating facilities. A Momentary Parallel Generation Contract is required for this type of service.

(Continued)

Schedule TOU-PA-3-RTP Sheet 7 (T)
AGRICULTURAL AND PUMPING - LARGE
TIME OF USE - REAL TIME PRICING
(Continued)

SPECIAL CONDITIONS (Continued)

13. Billing Calculation A Customer's bill is calculated according to the rates and conditions above. The charges listed in the Rates section which compose of Total Delivery Service rates and Generation rates, are calculated by multiplying the Total Delivery Service Rate and the Generation rates, when applicable, by the billing determinants (e.g., per kilowatt [kW], kilowatt-hour [kWh], kiloVar [kVAR], etc.).

The total Delivery Service Charges, which composed of the monthly Customer Charge, Facility-related demand charge (FRD), Delivery Energy charges, and Power Factor Adjustment charges are calculated as followed:

a. Monthly Customer Charge.

b. FRD is determined by multiplying the metered maximum kW demand by the Facilities Related Demand Charge shown in the RATES section.

c. Delivery Energy charge is determined by multiplying the total kWh consumption by the energy charges shown in the RATES section.

d. Power Factor Adjustment charge is determined by multiplying the billing kVAR demand by the kVAR charges shown in the RATES section.

The Generation Charge is determined by multiplying the hourly kWh usage supplied by SCE by the hourly Generation energy charges shown in the RATES section.

Bundled Service Customers receive Delivery Service from SCE and receive supply Generation service from SCE. The Customer's bill is the sum of the charges for Delivery Service and Generation determined, as described in this Special Condition, and subject to applicable discounts or adjustments provided under SCE's tariff schedules.

(Continued)

Schedule TOU-PA-3-RTP Sheet 8 (T)
AGRICULTURAL AND PUMPING - LARGE
TIME OF USE - REAL TIME PRICING
(Continued)

SPECIAL CONDITIONS (Continued)

14. Customers with Service Metered and Delivered at Voltages above 50 kV (Sub-transmission Customers) Included in Rotating Outages.

Sub-transmission Customers, except for those Customers exempt from rotating outages, are to be included in controlled, rotating outages when required by the California Independent System Operator (CAISO). To the extent feasible, SCE will coordinate rotating outages applicable to Sub-transmission Customers who are fossil fuel producers and pipeline operators and users to minimize disruption to public health and safety. SCE shall not include a Sub-transmission Customer in an applicable rotating outage group if the Customer's inclusion would jeopardize electric system integrity. Sub-transmission Customers who are not exempt from rotating outages, and seek such exemption, may submit an Optional Binding Mandatory Curtailment (OBMC) Plan to SCE in accordance with Schedule OBMC. If SCE approves a Customer's OBMC Plan, the Customer will become exempt from rotating outages and will be subject to the terms and conditions of Schedule OBMC and its associated contract.

Non-exempt Sub-transmission Customers shall be required to drop their entire electrical load during applicable rotating outages by either (1) implementing the load reduction on their own initiative, in accordance with subsection a, below; or (2) having SCE implement the load reduction through remote-controlled load drop equipment (control equipment) in accordance with subsection b, below. A Sub-transmission Customer shall normally be subject to the provisions of subsection a. If SCE approves a Customer's request to have SCE implement the load reduction or if the Customer does not did not comply with prior required load reductions, as specified in subsection c, the Customer will be subject to the provisions of subsection b.

a. Customer-Implemented Load Reduction. (Continued)

(1) Notification of Required Load Reduction. At the direction of the CAISO or when SCE otherwise determines there is a need for Rotating Outage, SCE shall notify each Sub-transmission Customer in an affected rotating outage group to drop its entire load. Within 30 minutes of such notification, the Customer must drop its entire load. The Customer shall not return the dropped load to service until 90 minutes after SCE sent the notification to the Customer to drop its load, unless SCE notifies the Customer that it may return its load to service prior to the expiration of the 90 minutes.

(2) Method of Notification. The method in which SCE will notify Sub-transmission Customers, who are required to implement their own load reduction, includes email, phone, and/or text message. The Customer is responsible for providing SCE their designated contact(s) information and preferred method for notifications. Customers must ensure the notification delivery method is functional at all times and are responsible for their charges incurred with the notification delivery service. Failure to provide at least one functional notification contact may result in Excess Energy Charges. When SCE sends the notification to the designated contact(s) the Customer is responsible for dropping its entire load in accordance with subsection a., above.

(Continued)

Schedule TOU-PA-3-RTP Sheet 9 (T)
AGRICULTURAL AND PUMPING - LARGE
TIME OF USE - REAL TIME PRICING
(Continued)

SPECIAL CONDITIONS (Continued)

14. Customers with Service Metered and Delivered at Voltages above 50 kV (Sub-transmission Customers) Included in Rotating Outages. (Continued)

a. Customer-Implemented Load Reduction. (Continued)

(3) Excess Energy Charges. If a Sub-transmission Customer fails to drop its entire load within 30 minutes of notification by SCE, and/or fails to maintain the entire load drop until 90 minutes after the time notification was sent to the Customer, unless SCE otherwise notified the Customer that it may return its load to service earlier in accordance with subsection a. (1) above, SCE shall assess Excess Energy Charges of $6 per kWh for all kWh usage in excess of the Authorized Residual Ancillary Load. Such charges will be based on the total kWh usage during the applicable rotating outage penalty period, less the product of Authorized Residual Ancillary Load in kW and the applicable rotating outage penalty period in hours. Excess Energy Charges will be determined and applied by SCE subsequent to the Sub-transmission Customer's regularly scheduled meter read date following the applicable rotating outage.

(4) Authorized Residual Ancillary Load. Authorized Residual Ancillary Load is load that is deemed to be equivalent to five percent of the Sub-transmission Customer's prior billing month's recorded Maximum Demand. This minimum load level is used as a proxy to allow for no-load transformer losses and/or load attributed to minimum grid parallel operation for generators connected under Rule 21.

b. SCE-Implemented Load Reduction.

Non-exempt Sub-transmission Customers may request, in writing, to have SCE drop the Customer's entire load during all applicable rotating outages using SCE's remote-controlled load drop equipment (control equipment). If SCE agrees to such arrangement, SCE will implement the load drop by using one of the following methods:

(1) Control Equipment Installed. For a Sub-transmission Customer whose load can be dropped by SCE's existing control equipment, SCE will implement the load drop during a rotating outage applicable to the Customer. The Customer will not be subject to the Notification and Excess Energy Charge provisions set forth in subsection a, above.

(Continued)

Schedule TOU-PA-3-RTP Sheet 10 (T)
AGRICULTURAL AND PUMPING - LARGE
TIME OF USE - REAL TIME PRICING
(Continued)

SPECIAL CONDITIONS (Continued)

14. Customers with Service Metered and Delivered at Voltages above 50 kV (Sub-transmission Customers) Included in Rotating Outages. (Continued)

b. SCE-Implemented Load Reduction. (Continued)

(2) Control Equipment Pending Installation. For a Sub-transmission Customer whose load cannot be dropped by SCE's existing control equipment, the Customer must request the installation of such equipment at the Customer's expense in accordance with SCE's Rule 2, Section H, Added Facilities. Pending the installation of the control equipment, the Customer will be responsible for dropping load in accordance with the provisions of subsection a, above, including the Notification and Excess Energy Charge provisions.

c. Non-compliance: A non-exempt Sub-transmission Customer subject to subsection a, above, who fails to drop load during three rotating outages in a three year period to a demand level of 20% or less of the Customer's prior billing month's recorded Maximum Demand averaged over the applicable rotating outage period, is not in compliance with this tariff. The three year period shall commence with the first failure to drop load as specified in this subsection. A Customer not in compliance with this condition will be placed at the top of the Sub-transmission Customer rotating outage group list and will be expected to comply with subsequent applicable rotating outages. In addition, the Customer must select one of the two options below within fifteen days after receiving written notice of non-compliance from SCE. A Customer failing to make a selection within the specified time frame will be subject to subsection c. (2) below.

(1) Subject to Schedule OBMC: The Customer shall submit an OBMC Plan, in accordance with Schedule OBMC, within 30 calendar days of receiving written notice of non-compliance from SCE. Pending the submittal of the OBMC Plan by the Customer and pending the review and acceptance of the OBMC Plan by SCE, the Customer will remain responsible for dropping load in accordance with the provisions of subsection a, above, including the Notification and Excess Energy charge provisions. If the Customer fails to submit an OBMC Plan within 30 days of receiving notice of non-compliance from SCE, or if the Customer's OBMC Plan is not approved by SCE, or if the Customer fails to meet the requirements of Schedule OBMC once the OBMC Plan is approved, the Customer shall be subject subsection c. (2), below.

(Continued)

Schedule TOU-PA-3-RTP Sheet 11 (T)
AGRICULTURAL AND PUMPING - LARGE
TIME OF USE - REAL TIME PRICING
(Continued)

SPECIAL CONDITIONS (Continued)

14. Customers with Service Metered and Delivered at Voltages above 50 kV (Sub-transmission Customers) Included in Rotating Outages. (Continued)

c. Non-compliance: (Continued)

(2) Installation of Control Equipment. The Customer shall be subject to the installation of control equipment at the Customer's expense in accordance with SCE's Rule 2, Section H, Added Facilities, if such equipment is not currently installed. If such switching capability is installed, SCE will drop the Customer's load for all applicable subsequent rotating outages in accordance with the provisions of subsection b, above. Pending the installation of control equipment, the Customer will remain responsible for dropping load in accordance with the provisions of subsection a, above, including the Notification and Excess Energy Charge provisions.

d. Net-Generators

Sub-transmission Customers who are also net-generators are normally exempt from rotating outages, but they must be net suppliers of power to the grid during all rotating outages. For the purpose of this Special Condition, a net-generator is an SCE Customer who operates an electric generating facility as part of its industrial or commercial process, and the generating facility normally produces more electrical power than is consumed in the industrial or commercial process, with the excess power supplied to the grid. Sub-transmission Customers whose primary business purpose is to generate power are not included in this Special Condition.

(1) Notification of Rotating Outages. SCE will notify sub-transmission Customers who are net-generators of all rotating outages applicable to Customers within SCE's service territory. Within 30 minutes of notification, the Customer must ensure it is a net supplier of power to the grid throughout the entire rotating outage period. Failure to do so will result in the Customer losing its exemption from rotating outages, and the Customer will be subject to Excess Energy Charges, as provided below.

(Continued)

Schedule TOU-PA-3-RTP Sheet 12 (T)
AGRICULTURAL AND PUMPING - LARGE
TIME OF USE - REAL TIME PRICING
(Continued)

SPECIAL CONDITIONS (Continued)

14. Customers with Service Metered and Delivered at Voltages above 50 kV (Sub-transmission Customers) Included in Rotating Outages. (Continued)

d. Net-Generators (Continued)

(2) Excess Energy Charges. Net generators who are not net suppliers to the grid during each rotating outage period will be subject to Excess Energy Charges of $6 per kWh for all kWh usage in excess of the Authorized Residual Ancillary Load. Such charges will be based on the total kWh usage during a rotating outage penalty period, less the product of Authorized Residual Ancillary Load in kW and the applicable rotating outage period hours. Excess Energy Charges will be determined and applied by SCE subsequent to the Customer's regularly scheduled meter read date following the applicable rotating outage. Excess Energy Charges shall not apply during periods of verifiable scheduled generator maintenance or if the Customer's generator suffers a verifiable forced outage. The scheduled maintenance must be approved in advance by either the CAISO or SCE, but approval may not be unreasonably withheld.

(Continued)

Schedule TOU-PA-3-RTP Sheet 13
AGRICULTURAL AND PUMPING - LARGE
TIME OF USE - REAL TIME PRICING
(Continued)

SPECIAL CONDITIONS (Continued)

14. Customers with Service Metered and Delivered at Voltages above 50 kV (Sub-transmission Customers) Included in Rotating Outages. (Continued) (T)

c. Non-compliance: (Continued)

(2) Installation of Control Equipment. The Customer shall be subject to the installation of control equipment at the Customer's expense in accordance with SCE's Rule 2, Section H, Added Facilities, if such equipment is not currently installed. If such switching capability is installed, SCE will drop the Customer's load for all applicable subsequent rotating outages in accordance with the provisions of subsection b, above. Pending the installation of control equipment, the Customer will remain responsible for dropping load in accordance with the provisions of subsection a, above, including the Notification and Excess Energy Charge provisions. (T)

d. Net-Generators

Sub-transmission Customers who are also net-generators are normally exempt from rotating outages, but they must be net suppliers of power to the grid during all rotating outages. For the purpose of this Special Condition, a net-generator is an SCE Customer who operates an electric generating facility as part of its industrial or commercial process, and the generating facility normally produces more electrical power than is consumed in the industrial or commercial process, with the excess power supplied to the grid. Sub-transmission Customers whose primary business purpose is to generate power are not included in this Special Condition. (T)

(1) Notification of Rotating Outages. SCE will notify sub-transmission Customers who are net-generators of all rotating outages applicable to Customers within SCE's service territory. Within 30 minutes of notification, the Customer must ensure it is a net supplier of power to the grid throughout the entire rotating outage period. Failure to do so will result in the Customer losing its exemption from rotating outages, and the Customer will be subject to Excess Energy Charges, as provided below. (T)

(Continued)

Schedule TOU-PA-3-RTP Sheet 14
AGRICULTURAL AND PUMPING - LARGE
TIME OF USE - REAL TIME PRICING
(Continued)

SPECIAL CONDITIONS (Continued)

14. Customers with Service Metered and Delivered at Voltages above 50 kV (Sub-transmission Customers) Included in Rotating Outages. (Continued) (T)

d. Net-Generators (Continued)

(2) Excess Energy Charges. Net generators who are not net suppliers to the grid during each rotating outage period will be subject to Excess Energy Charges of $6 per kWh for all kWh usage in excess of the Authorized Residual Ancillary Load. Such charges will be based on the total kWh usage during a rotating outage penalty period, less the product of Authorized Residual Ancillary Load in kW and the applicable rotating outage period hours. Excess Energy Charges will be determined and applied by SCE subsequent to the Customer's regularly scheduled meter read date following the applicable (T)
rotating outage. Excess Energy Charges shall not apply during periods of (T)
verifiable scheduled generator maintenance or if the Customer's generator suffers a verifiable forced outage. The scheduled maintenance must be approved in advance by either the CAISO or SCE, but approval may not be unreasonably withheld.

(Continued)

California ISO
Shaping a Renewed Future

DEMAND ANALYSIS WORKING GROUP (DAWG)

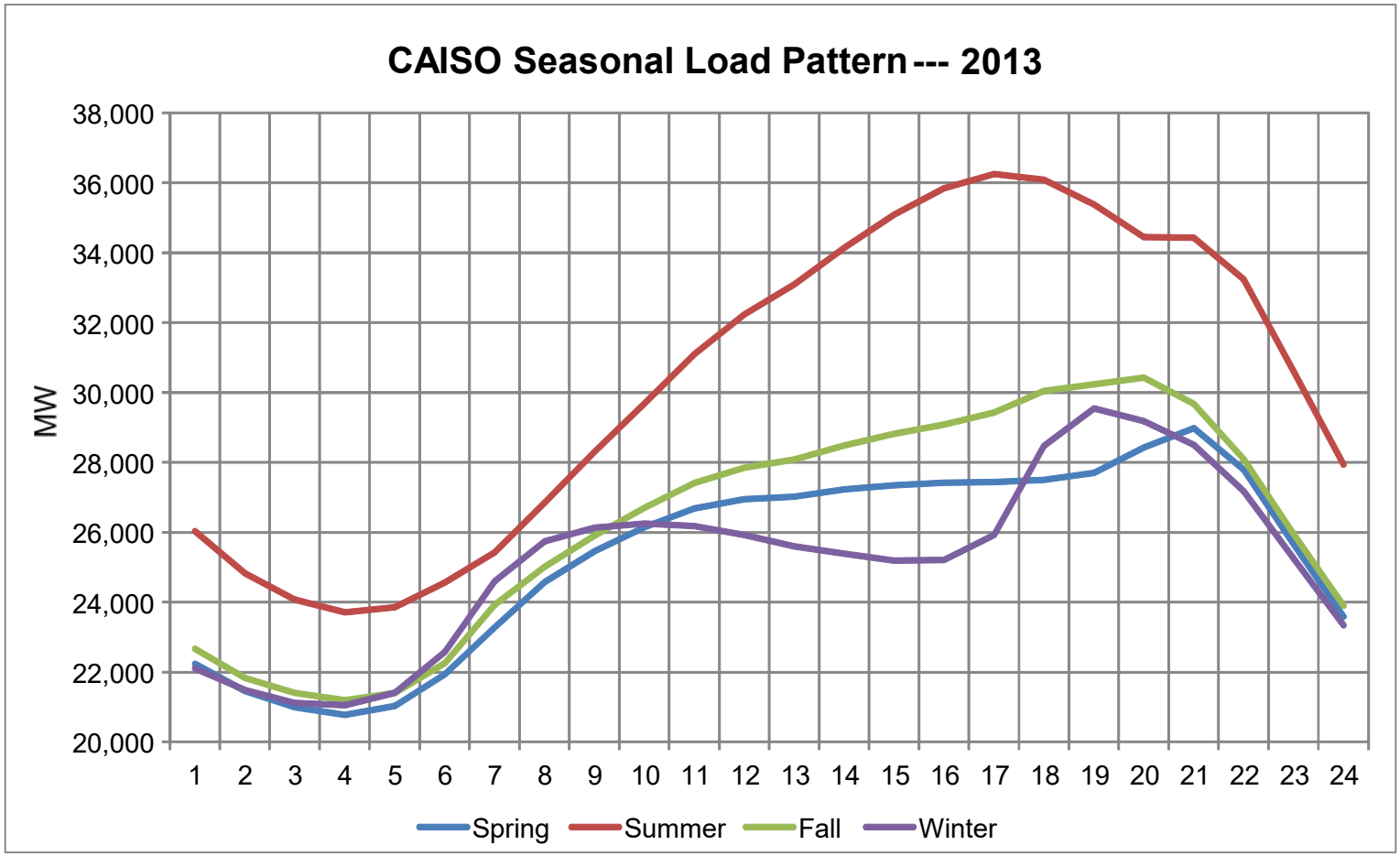
Operational needs and how rate design can help

Clyde Loutan, Sr. Advisor, Renewable Energy Integration

Pacific Energy Center
851 Howard Street, San Francisco

October 7, 2014

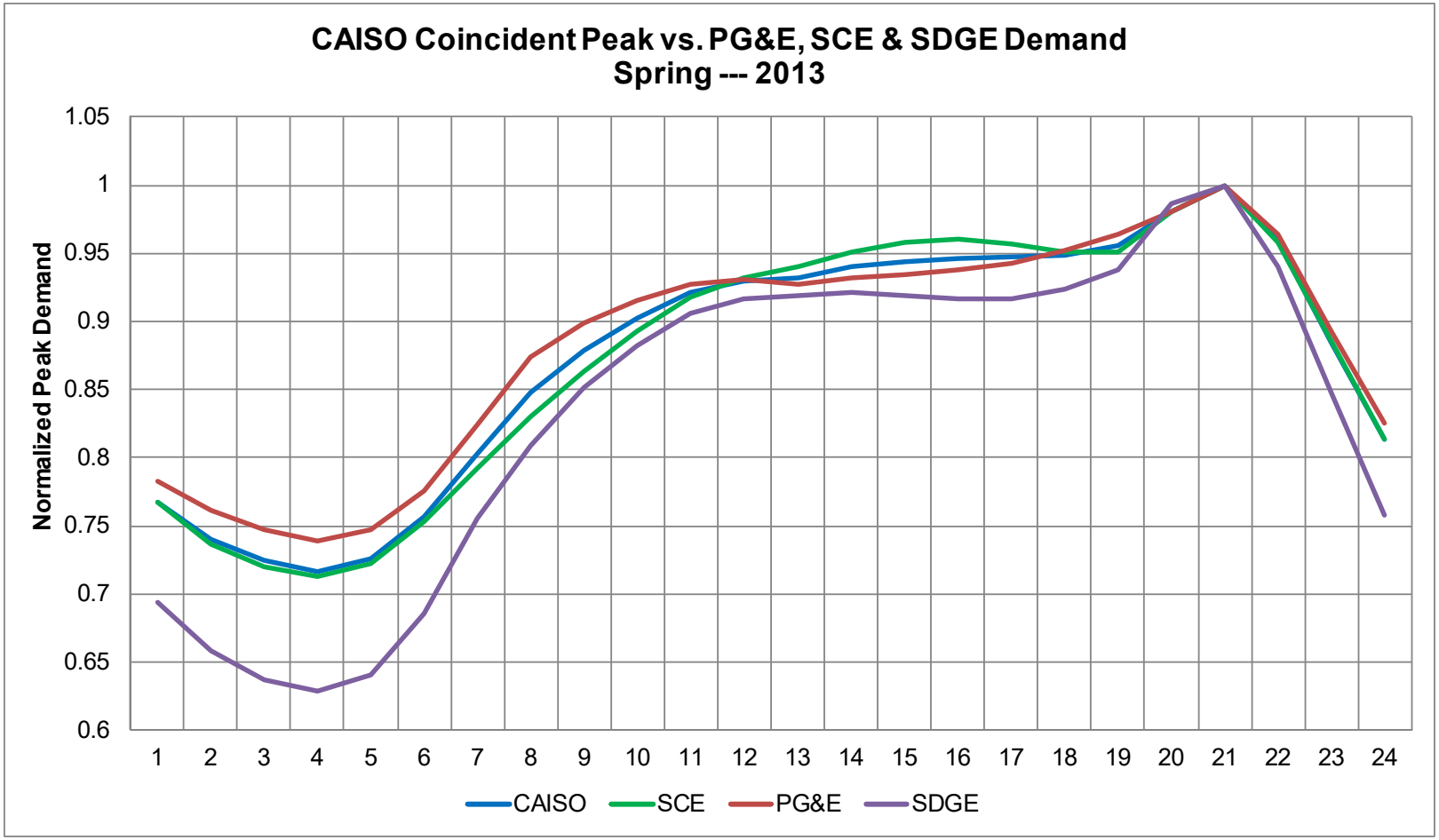
The CAISO coincident peak demand varies by season



Up to a 4-hour spread across the year

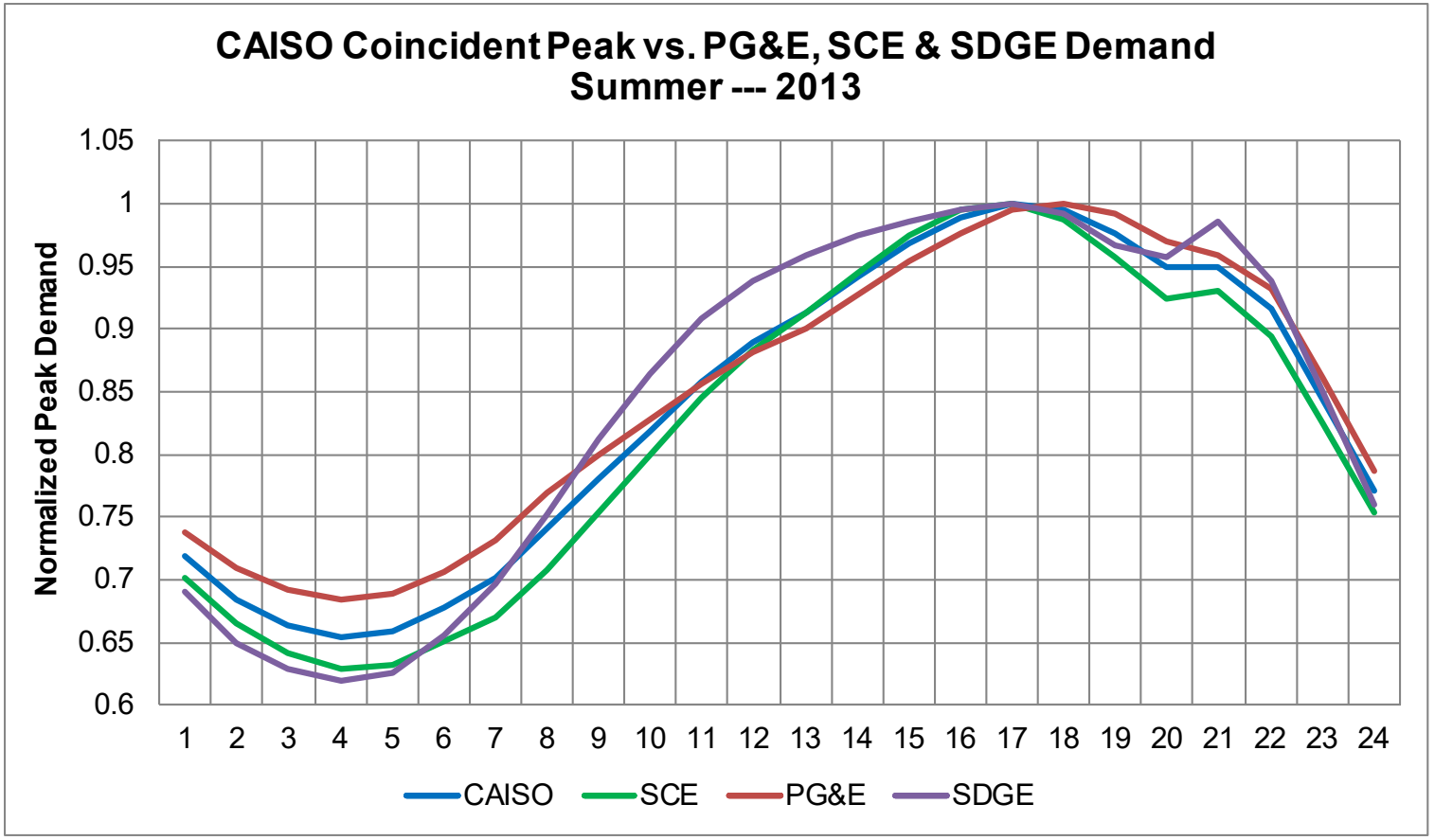
Spring: Mar, Apr & May (HE 21)	Fall: Sep, Oct & Nov (HE 20)
Summer: Jun, Jul & Aug (HE 17)	Winter: Dec, Jan & Feb (HE 19)

During the spring, the ISO coincident peak occurs about the same time as the three PTOs between 8 p.m. and 9 p.m.



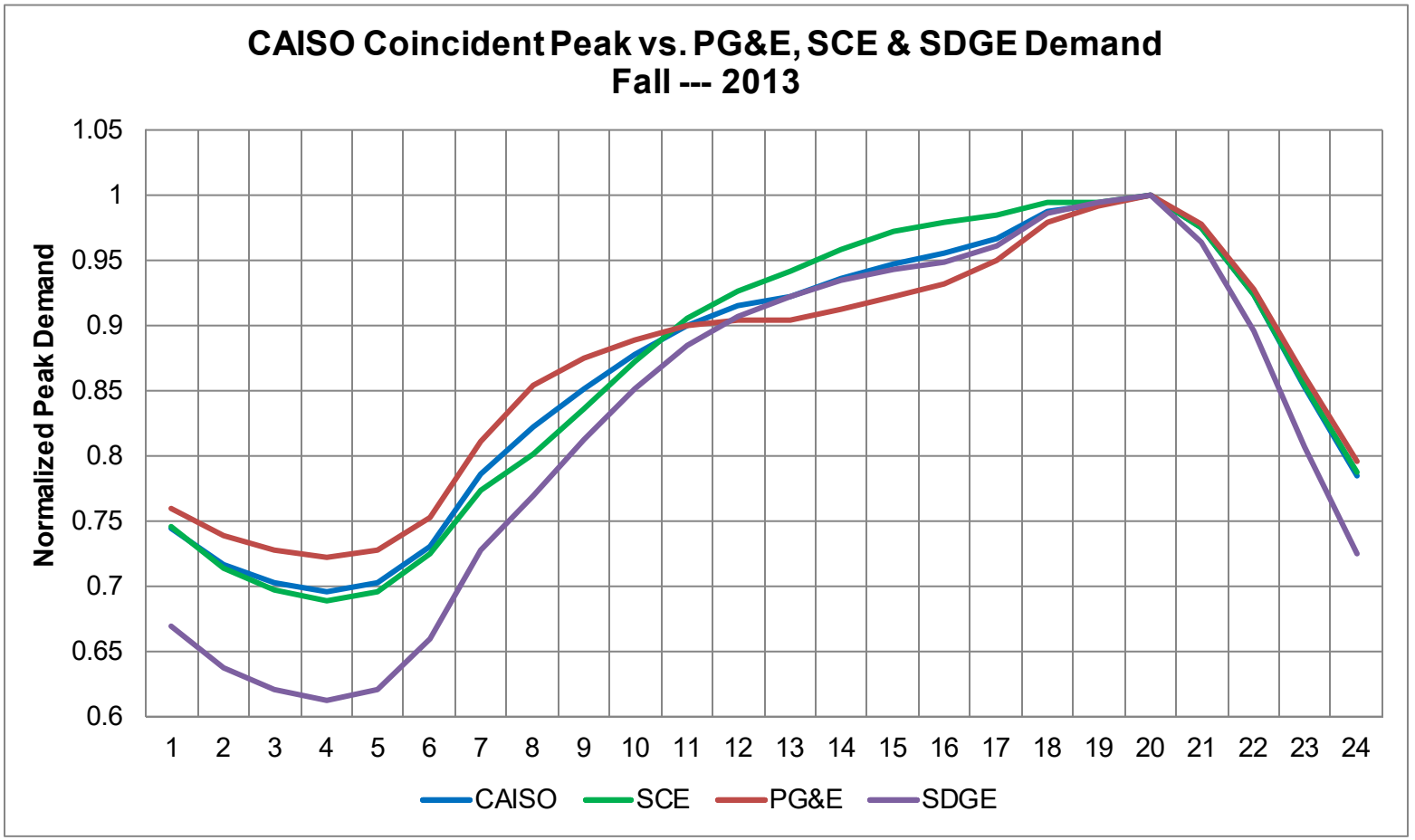
CAISO Peak: 28,981 MW	PG&E Peak:13,142 MW
SCE: 13,065 MW	SDGE: 2,726 MW

During the summer, the CAISO's coincident peak occurs about the same time as SCE & SDGE between 4:00 p.m. and 5:00 p.m. PG&E's peak occurs an hour later between 5:00 p.m. and 6:00 p.m.



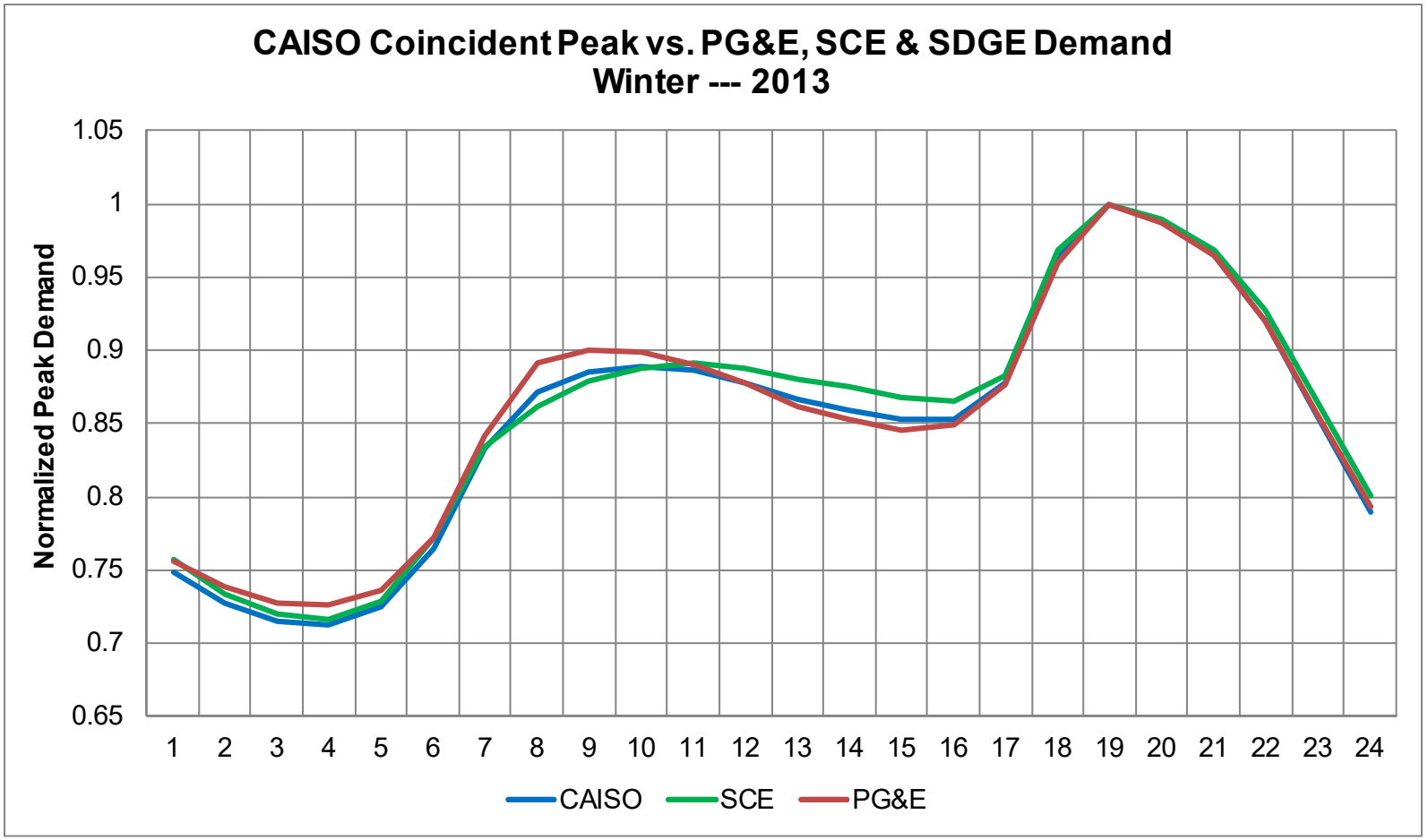
CAISO Peak: 36,246 MW	PG&E Peak:16,470 MW
SCE: 16,699 MW	SDGE: 3,071 MW

During the fall, the CAISO's coincident peak occurs about the same time as the PTOs peak which occurs between 7:00 p.m. and 8:00 p.m.



CAISO Peak: 30,422 MW	PG&E Peak:13,533 MW
SCE: 13,862 MW	SDGE: 2,975 MW

During the winter, the CAISO's coincident peak coincides with the PTOs peak demand between 6:00 p.m. and 7:00 p.m.



Docket No.: A.16-06-013

Exhibit No.: _____

Date: March 15, 2017

Witnesses: Richard McCann and Laura Norin

TESTIMONY OF RICHARD MCCANN AND LAURA NORIN ON BEHALF OF THE AGRICULTURAL PARTIES IN PACIFIC GAS & ELECTRIC'S (PG&E'S) 2017 GENERAL RATE CASE PHASE 2 APPLICATION ADDRESSING PG&E'S AGRICULTURAL CLASS BALANCING ACCOUNT STUDY

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Attachment D: Irrigation Training and Research Center, "California Agricultural Electrical Energy Requirements," Prepared for the California Energy Commission PIER Program

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Attachment F: Fallowed Area Mapping for Drought Impact Reporting: 2015 Assessment of Conditions in the California Central Valley

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Attachment H: U.S. Bureau of Reclamation. "Summary of Water Supply Allocations"

Attachment I: California Department of Water Resources Sacramento River Runoff Index

Attachment J: Prepared Direct Testimony of Richard McCann, Ph.D. On Marginal Costs, Revenue Allocation, And Rate Design Issues On Behalf Of The Agricultural Energy Consumers Association, A.13-04-012

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I. INTRODUCTION OF AGRICULTURAL PARTIES

The Agricultural Parties, comprised of the Agricultural Energy Consumers Association ("AECA") and the California Farm Bureau Federation ("Farm Bureau"), submit this testimony in Pacific Gas & Electric Company's ("PG&E") 2017 General Rate Case Phase II proceeding to address PG&E's Agricultural Class Balancing Account Study and to move forward the assessment of the revenue distortions that arise as a result of hydrological-related mismatches between forecasted and actual Agricultural class sales.[1]

AECA is a nonprofit organization representing the energy interests of California agriculture. AECA was founded in 1991 by growers and other members of the agricultural community concerned about electricity costs. AECA represents the collective interests of the state's leading agricultural associations and also works on behalf of the combined interests of several county Farm Bureaus and more than forty agricultural water districts.[2] AECA's membership is broad-based, reflecting family farmers from Redding in the north to San Diego in the south who grow crops ranging from alfalfa to walnuts. Through its members and membership associations, AECA represents in excess of 40,000 California agricultural producers.

[1] Please see Appendix A for the qualifications of Richard McCann, witness for AECA, and Laura Norin, witness for Farm Bureau.

[2] Membership associations include California Citrus Mutual, Western Growers Association, California Fresh Fruit Association, Milk Producers Council, California Dairies Inc., California Poultry Federation, Almond Hullers and Processors Association, California Grain and Feed Association, Agricultural Council, Western Agricultural Processors Association, and California Cotton Ginners' and Growers' Association

Farm Bureau is California's largest farm organization with approximately 48,000 members in 53 county Farm Bureaus.[3] Farm Bureau is a voluntary, non-governmental, non-profit organization. Farm Bureau strives to protect and improve the ability of farmers and ranchers engaged in production agriculture to provide a reliable supply of food and fiber through responsible stewardship of California's resources. Farm Bureau works with the various county Farm Bureaus and their members throughout the PG&E service territory to identify solutions to address issues raised in this proceeding.

AECA and Farm Bureau are intervening in this proceeding to advocate for fair electricity rates for their members. In addition to this joint testimony, separate testimony is being submitted from each organization focusing on revenue allocation and agricultural rate design issues.

II. BACKGROUND AND TESTIMONY OVERVIEW

Agricultural electricity demand is highly sensitive to water availability. Under normal conditions, water from the State Water Project and Central Valley Project canal systems and other sources of surface water are key sources of irrigation water for many California farmers. Under dry conditions, these water sources can be sharply curtailed and even eliminated at the same time that irrigation requirements are heightened. As a result, farmers rely more heavily on groundwater, which requires much more energy to pump than does surface water since groundwater must be lifted from deeper depths. Over extended droughts, like the 2012 to 2016 period that we are just emerging from,

[3] California farmers and ranchers sell $44.7 billion in agricultural products annually and account for hundreds of thousands of jobs in California. Farm Bureau's members expected to pay in excess of $1 billion for their electric service in 2016.

the groundwater level falls, and groundwater must be pumped from ever deeper depths, requiring even more energy to meet crops' water needs. As a result, even as land is fallowed in response to the water scarcity, significantly more energy is required to meet the water needs of remaining crops. Much less pumping is needed in years with ample surface water supply as rivers rise, soils become saturated, and aquifers recharge, raising the groundwater level.

As a result, year-to-year agricultural electricity sales vary substantially with changes in water conditions. Yet, the Agricultural class's assigned PG&E revenue responsibility is based on the assumption that "normal" water conditions will be in place every year, without accounting for how variations from normal conditions will affect rates and revenues for agricultural and other customers. This premise results in an imbalance in revenue collection from the class that does not correct itself even over long periods of time and that harms agricultural customers most in drought years, when they can least afford it. Our analysis presented later shows that overcollections can be expected to reach $171 million over two years of typical drought conditions.[4] As demonstrated below, this collection imbalance also increases rate instability for other customer classes.

[4] See Table 9, row 16.

In PG&E's 2014 GRC Phase II proceeding, the Agricultural Parties raised the problem of "the high level of sales variability and sales forecast uncertainty pertaining to the agricultural class, principally as a result of the unpredictability of the availability of surface water."[5] That proceeding's Marginal Cost and Revenue Allocation Settlement attempted to address this issue by requiring PG&E to conduct a workshop process culminating in the development of an Agricultural Class Balancing Account Study evaluating the desirability of deploying a balancing account to address the revenue implications of agricultural sales variability and unpredictability.

As directed, PG&E held workshops and included an Agricultural Class Balancing Account Study ("Study") as an attachment to PG&E's 2017 GRC Phase II application.[6] However, PG&E's Study does not accurately depict the revenue implications of agricultural sales variability and unpredictability and does not propose a mechanism to address the revenue imbalances, leaving the problem unresolved. The Agricultural Parties demonstrate in this testimony that PG&E's Study is extremely flawed and that the revenue implications of agricultural sales variability and unpredictability are substantial and that they reduce rate stability for all customers, not just agricultural customers.

[5] Settlement Agreement on Marginal Cost and Revenue Allocation in Phase II of Pacific Gas and Electric Company's 2014 General Rate Case, A.13-04-012, July 16, 2014, (2014 Phase II Settlement Agreement) page 15. (See Attachment C)

[6] PG&E 2017 General Rate Case Phase II Updated and Amended Prepared Testimony, Exhibit PG&E-08 Volume 2, December 2, 2016 (PG&E-08, Vol. 2), Appendix F.

III. PG&E'S STUDY DOES NOT CLARIFY THE REVENUE IMPLICATIONS OF AGRICULTURAL SALES VARIABILITY

As discussed in the Agricultural Parties' comments on PG&E's Study, which were included as an addendum to PG&E's 2017 GRC Phase II application,[7] the Study does not shed light on the key question it was charged to address. On account of both methodological deficiencies and data errors, the Study's findings as to the revenue implications of agricultural sales variability are, unfortunately, meaningless. After summarizing some of these deficiencies in this chapter, the Agricultural Parties will present its own assessment of this issue in Chapter IV.

A. PG&E'S METHODOLOGICAL APPROACH IS NOT USEFUL FOR EVALUATING THE RELATIONSHIP BETWEEN LOAD DEVIATIONS AND REVENUE COLLECTIONS (WITNESS: R. MCCANN)

PG&E's Study was charged with evaluating the extent to which revenue distortions arise on account of agricultural load variability.[8] A meaningful assessment of these revenue distortions would require an apples-to-apples comparison of (i) revenue collected through agricultural rates and (ii) actual agricultural class revenue responsibility, assessed based on actual loads. For this comparison to be apples-to-apples, the assessment of actual revenue responsibility must use the same methodology and data as were used in the analyses that underlie the formation of customer rates, except for the updated agricultural load amount.[9] In PG&E's Study, however, the actual revenue responsibility assessment is based on different assumptions than were used to develop customer rates. For example, the actual

[7] PG&E 2017 General Rate Case Phase II, Exhibit PG&E-08 Volume 2, Addendum To Appendix F (Agricultural Parties Comments on PG&E Study).
[8] 2014 Phase II Settlement Agreement, page 15. (See Attachment C)
[9] See Agricultural Parties Comments on PG&E Study, page 3 for further discussion.

revenue responsibility assessment was derived from uncapped GRC allocations, whereas rates were developed based on capped GRC allocations that were further adjusted with annual Energy Resource Recovery Account (ERRA) rebalancing. In addition, for the actual revenue responsibility assessment, PG&E updated loads and billing determinants not just for the Agricultural class, but also for all other classes, further confounding any useful comparison.

In addition, PG&E's analysis failed to account for the accumulation of revenue distortions over time, and it assumed that variances in sales due to hydrologic conditions affect *all* marginal costs, including customer access and distribution costs. As demonstrated below, this is not the case, and it leads to significant revenue distortions.

Furthermore, by evaluating only scenarios in which rates are set with perfect foresight, PG&E's Study failed to account for the impacts of sales forecast error. In practice, rates are set each year to recover the expected revenue requirement based on a sales forecast that assumes "normal" water conditions. Differences between the revenues that are collected from these rates over the course of the year and PG&E's actual revenue requirement for the year (i.e., over- and undercollections) are applied to the following year's revenue target. Importantly, PG&E does not allocate these over- or undercollections to the rate class responsible for the differences. Instead, these over- or undercollections are allocated to all customers. As a result, agricultural revenue overcollections from dry years (i.e., years of higher agricultural pumping load) result in rate reductions for non-agricultural customer classes, and revenue undercollections from wet years (i.e., years of lower agricultural pumping load) prompt rate increases for these other customer classes. These effects are not seen in PG&E's Study because the

Study does not evaluate the effects of sales forecast error, instead evaluating only hypothetical (and unrealistic) scenarios in which PG&E's revenue responsibility assessments are made with perfect foresight as to future sales conditions.

For all these reasons, PG&E's Study does not accurately assess the revenue distortions from agricultural load variability, neither the distortions for agricultural customers nor the distortions for other customers.

B. THE DATA USED IN PG&E'S STUDY APPEAR TO BE HIGHLY UNRELIABLE (WITNESS: L. NORIN)

In addition to the methodological flaws discussed above, there are numerous analytical and data errors in PG&E's Study, as discussed further in the Agricultural Parties' comments on PG&E's Study.[10] While PG&E made corrections to generation Peak Cost Allocation Factors (PCAFs) in response to the Agricultural Parties' observations,[11] most of the data and analytical flaws remain. For example, the following concerns raised by the Agricultural Parties are still relevant in PG&E's latest set of workpapers for its Study,[12]

1. "PCAF and [final line transformer (FLT)] loads should have a fairly constant relationship to energy load, especially when averaged across a large number of customers; yet this is not always the case in PG&E's dataset. For example, from 2012 to 2013 the ratio of sales to FLT increases nearly 20% for the entire system (from 0.33 to 0.40) and rises 160% for E-20 and standby customers (from 0.11 to 0.29)."[13] **This issue remains.**

2. "Year-to-year load variations are much higher in PG&E's dataset than would be expected for large groups of customers. For example, the distribution

[10] PG&E-08, Vol. 2, Addendum to Appendix F.
[11] Notice of Availability of Pacific Gas and Electric Company's (U 39 M) 2017 General Rate Case Phase II Updated And Amended Testimony, A.16-06-013, December 2, 2016, page 2.
[12] See PG&E workpapers, "GRC comparison.xlsx," sheet "FLT & PCAF by Year."
[13] Agricultural Parties Comments on PG&E Study, page 2. Note that the ratios indicated are ratios of FLT to sales, not sales to FLT.

PCAF varies from year-to-year by as much as 30% for residential customers; the FLT, by as much as 44% for small L&P customers."[14] **This issue remains.**

3. "The PCAF and FLT should generally move in lockstep; instead the relationships vary significantly across the years. For example, according to PG&E's data, the ratio of distribution PCAF to FLT for E-20 and standby customers was 0.68 in 2012 and 0.33 in 2013; the ratio of generation PCAF to FLT for this customer grouping fell from over 1.0 in 2011 and 2012 to around 0.5 in 2013 and 2014."[15] **This issue remains, though the amount of the generation PCAFs are now lower due to PG&E's partial correction.[16]**

4. "In the analysis reviewed, which uses 2014 GRC marginal costs with 2013 recorded data, there are numerous significant differences between the revenue requirements obtained after dividing and multiplying by actual sales ("final RRQ") and initial revenue responsibilities obtained from multiplying marginal costs by actual FLT and PCAF loads ("initial RRP")."[17] **This issue remains.**

In addition, the Agricultural Parties have subsequently obtained additional information from PG&E on its historic load data and found other flaws with the data used in PG&E's Study. For example, the generation PCAFs used in PG&E's Study do not match historical generation PCAFs provided in a PG&E data response,[18] with the system-wide total in PG&E's Study 10% lower than shown in the historical dataset over the 2011 to 2014 period, and the totals for individual customer classes in PG&E's Study as much as 37% lower or 109% higher than in the historical dataset over this same period (Table 1).[19]

[14] Agricultural Parties Comments on PG&E Study, page 2. Note that the maximum year-to-year change in FLTs that is shown for Small L&P customers is 42%, not 44%.
[15] Agricultural Parties Comments on PG&E Study, page 2.
[16] In the latest workpapers, the ratios of PCAFs to FLTs are about 0.7-0.8 in 2011-2012 and 0.3 in 2013-2014.
[17] Agricultural Parties Comments on PG&E Study, page 4.
[18] PG&E response to CFBF Data Request 06 Question 1, attachment 1. (See Attachment B)
[19] Note that while the two generation PCAF datasets are inconsistent, they both appear to be flawed. AECA and Farm Bureau address discrepancies with the "actual" generation PCAF data and other data used in PG&E's cost studies in our individual testimonies.

Table 1: 2011-2014 Average Generation PCAFs (kW)

	Historical "actual" PCAFs[20]	PCAFs used in PG&E's Study[21]	Difference
Residential	8,882,935	7,262,708	-18%
Small L&P	1,566,737	1,576,688	1%
Medium L&P	1,893,165	1,751,072	-8%
E-19	859,655	1,799,606	109%
Streetlight	22,837	22,167	-3%
Standby	44,095	37,004	-16%
Agricultural	1,437,121	1,312,473	-9%
E-20-T	756,457	526,963	-30%
E-20-P	1,053,241	666,786	-37%
E-20-S	364,059	254,426	-30%
Total	16,880,301	15,209,893	-10%

Annual trends in generation PCAFs are also not consistent across the two datasets. For example, PG&E's Study shows Agricultural class generation PCAFs falling by 22% in 2014,[22] while the historical dataset shows Agricultural class generation PCAFs increasing by 4% in that year.[23] Incidentally, the 22% reduction in Agricultural class generation PCAFs used in PG&E's Study for 2014 does not appear to be consistent with the 9% increase in Agricultural class distribution PCAFs and 8% increase in Agricultural class sales shown in the Study workpapers for that year.[24]

Similar problems can be seen in other datasets. For example, while the historical FLT dataset matches the Agricultural class FLTs used in PG&E's Study for 2011 and

[20] PG&E response to CFBF Data Request 06 Question 1, attachment 1. (See Attachment B)
[21] PG&E study workpaper, "GRC comparison.xlsx" in folder "GRC with actuals - all with 2014 MCs," sheet "FLT & PCAF by Year," rows 3-16, columns E, K, Q, and W.
[22] Calculated from PG&E study workpaper, "GRC comparison.xlsx," sheet "FLT & PCAF by Year," Q12 and W12.
[23] Calculated from PG&E response to CFBF Data Request 06 Question 1, attachment 1, sheets "AVGSPCAF13," cells B2:D2, and "AVGSPCAF14," cells D2:F2. (See Attachment B)
[24] Calculated from PG&E study workpaper, "GRC comparison.xlsx," sheet "FLT & PCAF by Year," N12:O12 and T12:U12.

2012, the Agricultural class FLTs used in PG&E's Study are 8% higher than those in the historical dataset for 2013 and 2014.[25]

On account of the myriad problems with PG&E's data and analysis, PG&E's Study cannot be relied on to draw any conclusions regarding the relationship between Agricultural class sales variance and revenue under- or overcollections.

IV. RATE DISTORTIONS FROM AGRICULTURAL CLASS SALES VARIABILITY

Year-to-year fluctuations in water availability, primarily due to oscillations in rainfall and snowpack, result in a high degree of year-to-year variability in the amount of electricity needed by agricultural customers to pump irrigation water. As demonstrated below, because these variations are not accounted for in the revenue allocation process, which is based on "normal" water conditions, they create rate distortions for all ratepayers.

A. AGRICULTURAL CLASS LOAD VARIABILITY AND LOAD FORECAST ERROR (WITNESS: L. NORIN)

Attachment 4, Table 1, of PG&E's Study confirms the unusually high load variability of the Agricultural class and the associated difficulty for PG&E in forecasting Agricultural class sales. Table 2, which was calculated from Table 1 of PG&E's Study, compares actual sales for each customer class to the class's 1995-2014 average sales.

[25] Calculated from PG&E study workpaper, "GRC comparison.xlsx," sheet "FLT & PCAF by Year," P12 and V12, and from PG&E CONFIDENTIAL response to CFBF Data Request 05 Question 1, attachment 1, sheets "DIVSWNCL13," cells C2:E20, and "DIVSWNCL14," cells E2:G20 and AA2:AC20. (See Attachment B)

Table 2: Sales Variability: Annual Sales Compared to 1995-2014 Class-Average Sales[26]

	Residential	Commercial	Industrial	Agricultural
1995	-16%	-15%	8%	-25%
1996	-12%	-12%	1%	-22%
1997	-10%	-9%	9%	-15%
1998	-7%	-9%	5%	-34%
1999	-4%	-4%	8%	-20%
2000	-1%	1%	9%	-18%
2001	-7%	-2%	8%	-11%
2002	-6%	-3%	-14%	-15%
2003	0%	1%	-5%	-16%
2004	2%	2%	-4%	-7%
2005	3%	3%	-4%	-19%
2006	7%	6%	-2%	-17%
2007	6%	8%	-2%	16%
2008	9%	8%	4%	20%
2009	8%	5%	-4%	25%
2010	6%	4%	-7%	9%
2011	7%	4%	-6%	1%
2012	7%	4%	-1%	33%
2013	7%	4%	-3%	51%
2014	3%	3%	1%	64%
Minimum	-16%	-15%	-14%	-34%
Maximum	9%	8%	9%	64%

For the Residential, Commercial, and Industrial classes, annual sales over this 20-year period varied between about 15% below and 10% above the class's average annual sales. For the Agricultural class, the variability was much greater, with annual sales ranging from about 35% below to 65% above annual average sales. In fact, Agricultural class sales were only within 15% below and 10% above the average annual sales in four of the 20 years analyzed.[27]

[26] Calculated from PG&E-08, Vol. 2, page F-Atch4-1.

[27] The four years in which agricultural load variability was within the range exhibited by the other customer classes were 2001, 2004, 2010, and 2011.

The reason for this high level of Agricultural class sales variability is that PG&E's agricultural customers use electricity predominantly to pump groundwater for irrigation and other agricultural purposes.[28] The amount of pumping that is needed in a given year depends heavily on the amount of surface water that is available and how deep the available groundwater is. In drought years, surface water deliveries through the State Water Project and the Central Valley Project are often sharply curtailed, as shown in Table 3. In addition, particularly in multi-year droughts, groundwater levels fall, requiring farmers to pump to deeper depths to obtain much-needed water to irrigate their crops and/or to let their fields lie fallow.[29] During the 2015 drought year, even with extensive fallowing,[30] PG&E agricultural customers' electricity usage was 63% higher than it had been in 2011,[31] due to the low availability of surface water and the need for deeper pumping. In particular, the deepening drought over the prior five years had depleted groundwater aquifers so that water was being pumped from greater depths, increasing electrical loads.

[28] Irrigation Training and Research Center, "California Agricultural Electrical Energy Requirements," Prepared for the California Energy Commission PIER Program, ITRC Report No. R 03-006, California Polytechnic State University, San Luis Obispo, California, December 2003, Table 1. (See Attachment D)
[29] The general energy use equation is 1.024 kilowatt-hours for each acre-foot lifted one more foot in depth at 100% efficiency. Tulare County Cooperative Extension, "Energy and Cost Required to Lift or Pressurize Water," Pub. IG6-96, University of California, page 2. (See Attachment E)
[30] For example, in 2015, farmers in the Central Valley fallowed more than a million acres, which was well over double the 400,000 acres that were fallowed during 2011. Melton, Rosevelt, Guzman, et. al. "Fallowed Area Mapping for Drought Impact Reporting: 2015 Assessment of Conditions in the California Central Valley," NASA Ames Research Center Cooperative for Research in Earth Science Technology and Education & CSU Monterey Bay, U.S. Geological Survey, U.S. Department of Agriculture National Agricultural Statistics Service, and California Department of Water Resources. October 14, 2015, Table 1, page 4. (See Attachment F)
[31] 63% = 7,657 GWh of 2015 retail Ag sales/4,691 GWh of 2011 retail Ag sales –1. (PG&E response to CFBF Data Request 04 Question 1d. (See Attachment B))

Table 3: Final State Water Project (SWP) and Central Valley Project (CVP) Water Allocations since 2010, % of requests

	SWP Allocation[32]	CVP Allocation[33]
2010	50%	45%
2011	80%	80%
2012	65%	40%
2013	35%	20%
2014	5%	0%
2015	20%	0%
2016	60%	5%

Given the high variability of agricultural sales and its dependence on notoriously unpredictable rainfall, it should be expected that PG&E would have difficulty predicting agricultural sales levels. This, indeed, is what PG&E found in its Study. Whereas actual cumulative sales over the 1995 to 2014 period were, on average, extremely close to PG&E's predicted sales level for residential and commercial customers over this 20-year period and fairly close, too, for industrial customers, this was not the case for agricultural customers, for whom actual cumulative sales exceeded PG&E's sales forecasts by an average of 10% over this period (Table 4).

Moreover, the average forecast error in any given year was substantially higher for agricultural customers (at ±14%) than for other customers (at ±3-5%). Furthermore, the agricultural sales forecast error exceeded 30% during four of the last seven years of PG&E's dataset, a level of forecast error not approached in any year for any other customer group (Table 4).

[32] California Department of Water Resources. SWPAO Water Deliveries, Notices to State Water Contractors dated June 22, 2010; April 20, 2011; May 23, 2012; March 22, 2013; April 18, 2014; March 2, 2015; and April 21, 2016; available at http://www.water.ca.gov/swpao/deliveries.cfm. (See Attachment G)
[33] U.S. Bureau of Reclamation. "Summary of Water Supply Allocations," available at http://www.usbr.gov/mp/cvo/vungvari/water_allocations_historical.pdf (See Attachment H)

Table 4: Forecast Error: Actual Sales Compared to PG&E's Sales Forecast[34]

	Residential	Commercial	Industrial	Agricultural
1995	-1.8%	-2.8%	-4.6%	-8.5%
1996	2.1%	-0.4%	-9.9%	2.4%
1997	1.9%	3.3%	-4.8%	4.6%
1998	1.2%	1.4%	-7.5%	-18.0%
1999	3.3%	5.3%	-4.1%	5.4%
2000	5.7%	8.0%	-4.3%	8.2%
2001	-6.7%	-2.7%	-2.9%	21.2%
2002	3.4%	3.0%	-15.1%	17.0%
2003	5.9%	2.9%	-7.7%	2.9%
2004	3.3%	1.6%	-2.6%	7.7%
2005	2.0%	-0.2%	-2.3%	-6.6%
2006	3.2%	-0.4%	-0.5%	-2.0%
2007	-0.7%	2.5%	0.6%	16.1%
2008	-0.3%	1.2%	4.3%	30.6%
2009	-2.2%	-5.8%	-6.5%	31.0%
2010	-0.4%	-2.3%	-6.7%	-0.2%
2011	-1.0%	-3.2%	-1.0%	-9.1%
2012	-3.1%	-1.1%	2.0%	17.9%
2013	-3.5%	0.6%	-0.3%	39.2%
2014	-6.2%	-3.6%	7.6%	31.0%
1995-2014 Total	0.1%	0.2%	-3.5%	10.4%
Annual Average (absolute value)	2.9%	2.6%	4.8%	14.0%

As noted in the Agricultural Parties' comments on PG&E's Study, PG&E's data demonstrate both the greater sales forecast error for agricultural customers than for the other major customer groups and that these annual deviations do not average themselves out over time, instead resulting in a long-term underestimate of agricultural sales:[35]

[34] PG&E-08, Vol. 2, page F-Atch4-1 (Total line added by Agricultural Parties by summing total actual 1995-2014 sales and dividing by total forecasted 1995-2014 sales; Annual Average line added by Agricultural Parties by calculating the average of the absolute values of 1995-2014 sales forecast errors.)
[35] Agricultural Parties Comments on PG&E Study, page 5.

Inspection of the annual data shows that the variance between forecasted and actual sales is, on the whole, much greater for the agricultural class than for other customer classes. For residential and commercial customers, the variance did not exceed ±8.0% in any year in this period; for industrial customers, the variance exceeded ±8.0% in just two of the 20 years, with a peak variance of -15% in 2002. By contrast, for agricultural customers, the variance exceeded ±8.0% in 12 years (i.e., two-thirds of the period), exceeded ±16.0% in nine years, and even exceeded ±30.0% in four years, including a 39% variance in 2013 and a 31% variance in 2014.

Moreover, the Total line reveals that the under- and overestimates do not cancel each other out for agricultural customers, instead continuing to accumulate against the class. For residential and commercial customers, actual sales over the 20-year period were within a few tenths of a percent of forecasted sales; for industrial customers, actual sales were 3.5% below forecasted; and for agricultural customers, actual sales were more than 10% above forecasted sales.

Before concluding this discussion of agricultural load variability, it is important to note that this discussion has addressed only the variability in agricultural sales due to changing hydrological conditions, not the variability in peak loads or other marginal cost determinants. This is because, while agricultural customers' sales typically increase in dry years due to greater pumping load, PG&E's historic datasets indicate that other marginal cost determinants do not increase in proportion to the higher sales. For example, generation PCAFs do not rise in proportion to sales,[36] presumably because much of the added load comes from more frequent use of existing pumps instead of from adding new or larger pumps. Distribution PCAFs and FLTs similarly do not vary in a consistent manner with water conditions,[37] and the annual variation in the number of

[36] Based on PG&E's data, changes to agricultural sales are poor predictors of changes to generation PCAFs. For example, generation PCAFs increased by approximately the same amount in 2006 and in 2007 (13%-14%), while sales increased by 3% in 2006 and by 42% in 2007. In addition, year-to-year changes in generation PCAFs were in the opposite direction of year-to-year changes in sales in two of the ten years from 2005-2014. PG&E responses to CFBF Data Requests 04 Question 1d and CFBF Data Request 06 Question 1. (See Attachment B)

[37] Based on PG&E's data, changes to agricultural sales are poor predictors of changes to FLTs or distribution PCAFs. Over the years from 2000 to 2014, year-to-year changes in FLTs were in the opposite direction of year-to-year changes in sales in five years, and year-to-year changes in distribution PCAFs

agricultural accounts is always small, even when there are significant load swings.[38] The key factor that changes with hydrological conditions is just agricultural sales, and these tend to be higher than forecast by PG&E during dry years and lower than forecast by PG&E during wet years.

B. REVENUE IMPLICATIONS OF SALES FORECAST ERRORS - ILLUSTRATIVE EXAMPLES (WITNESS: L. NORIN)

Sales forecasts are important inputs into both revenue allocation and rate design. With regard to revenue allocation, sales forecasts are used to allocate marginal energy costs among customer classes. All else equal, a higher sales forecast for a customer class yields a higher marginal energy cost (because more power is needed to serve the customer) and, therefore, a higher revenue allocation. Once revenue allocations have been established, sales forecasts are used to divide the portion of revenue requirement to be recovered through energy rates into rates. Forecasts of time-related demand, non-coincident demand, and customer-months are used to divide the remainder of the revenue requirement into the appropriate rate components.

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were in the opposite direction of year-to-year changes in sales in three years. Furthermore, the changes to FLTs and distribution PCAFs were often many times larger or smaller than the changes to sales. For example, in 2006, distribution PCAFs increased by 9% while sales increased by 3%, and in 2012, distribution PCAFs increased by 3% while sales increased by 32%. Calculated from PG&E responses to CFBF Data Request 04 Question 1d and Question 3 (Atch 3) and from CFBF Data Request 05 Question 1 (CONFIDENTIAL), and from PG&E Study workpaper, "GRC comprison.xlsx," sheet "FLT & PCAF by Year." (See Attachment B)

[38] Based on PG&E's data, changes to agricultural sales are not good predictors of variations in the number of customer accounts. For example, there was a 0% change to the number of agricultural accounts both in 2010, when agricultural retail sales fell by 13%, and in 2013, when agricultural retail sales rose by 14%. Furthermore, from 2004-2014, year-over-year changes to agricultural retail sales ranged from -13% to +41%, whereas year-over-year changes to the number of agricultural accounts ranged from just -1% to +2. PG&E responses to CFBF Data Request 04 Question 1d and CFBF Data Request 04 Question 2c. (See Attachment B)

In PG&E's GRC Phase II models, sales forecasts are additionally used, along with recorded data on PCAFs and FLTs, to forecast PCAFs and FLTs for marginal capacity cost calculations. However, as noted above,[39] PG&E's historic data show that agricultural PCAFs and FLTs do not vary consistently with agricultural sales, and there is therefore no evident relationship between sales increases and capacity cost increases.[40] Energy is the only cost factor that evidently increases in proportion to agricultural sales.

Tables 5 and 6 below provide simplified illustrations of the revenue allocation and rate design process, adjusted to reflect the lack of causal relationship between agricultural sales and agricultural PCAFs and FLTs. In each example, rates are recovered 100% on a volumetric basis, and there are only two rate classes. In addition, the marginal cost-based revenue requirement is assumed to be equal to the utility's actual revenue requirement, the sales forecast used for revenue allocation is assumed to be the same as the sales forecast used for rate design, and effects of differing load shapes (such as sales being distributed across time-of-use periods differently for distinct customer classes) are not taken into consideration.

[39] See footnotes 36 - 38.

[40] In PG&E's cost models (workpaper "MCRev_GRC.xlsx"), capacity costs are allocated by calculating the revenue requirement based on historic PCAFs and FLTs and then scaling the revenue requirement based on the ratio of the sales forecast to the recorded sales from the historic period. This implicitly assumes that PCAFs and FLTs scale linearly with sales, which is not the case for agricultural customers.

Table 5: Illustrative Calculation of Revenue Allocation, Rate Design, and Revenue Collection (Wet Year)[41]

	Revenue Allocation and Rate Design (forecast basis)				
		Class A	**Class B**	**Total**	**Calculation Notes**
[1]	Sales Forecast (GWh)	**500**	**1,000**	**1,500**	Input
[2]	*Energy Marginal Cost ($000)*	*$25,000*	*$50,000*	***$75,000***	*Total (input) *Class Sales/Total Sales*
[3]	*Other Marginal Costs ($000)*	**$50,000**	**$100,000**	**$150,000**	*Input*
[4]	Total Marginal Cost ($000)	$75,000	$150,000	$225,000	[2]+[3]
[5]	Total Rate ($/kWh)	$0.15	$0.15	$0.15	[4]/([1]*1000)

	Actual Revenue Requirement and Revenue (wet year)				
		Class A	**Class B**	**Total**	**Calculation Notes**
[6]	Actual Sales (GWh)	**250**	**1,000**	**1,250**	Input
	Actual Costs				
[7]	*Actual Energy Marginal Cost ($000)*	*$12,500*	*$50,000*	*$62,500*	*[2]*[6]/[1]*
[8]	*Actual Other Marginal Cost ($000)*	*$50,000*	*$100,000*	*$150,000*	*[3]*
[9]	Actual Marginal Cost ($000)	$62,500	$150,000	$212,500	[7]+[8]
	Actual Revenues				
[10]	*Initial Revenue ($000)*	*$37,500*	*$150,000*	*$187,500*	*[5]*[6]*1000*
[11]	*Allocation of undercollection ($000)*	*$8,333*	*$16,667*	*$25,000*	*Total: [9]-[10]; Class: Total*Class Sales/Total Sales*
[12]	Actual Total Revenue ($000)	$45,833	$166,667	$212,500	[10]+[11]
	Cross-Subsidization				
[13]	Revenues minus Costs ($000)	-$16,667	$16,667	$0	[12]-[9]
	Rate Impact				
[14]	Effective Rate, $/kWh	$0.18	$0.17	$0.17	[12]/([6]*1000)

[41] Input values (sales and initial revenue requirements) are shown in **blue**; other values are calculated. Key results are shown in red.

Table 6: Illustrative Calculation of Revenue Allocation, Rate Design, and Revenue Collection (Dry Year)[42]

	Revenue Allocation and Rate Design (forecast basis)				
		Class A	**Class B**	**Total**	**Calculation Notes**
[1]	Sales Forecast (GWh)	**500**	**1,000**	**1,500**	Input
[2]	*Energy Marginal Cost ($000)*	*$25,000*	*$50,000*	***$75,000***	*Total (input) *Class Sales/Total Sales*
[3]	*Other Marginal Costs ($000)*	**$50,000**	**$100,000**	**$150,000**	*Input*
[4]	Total Marginal Cost ($000)	$75,000	$150,000	$225,000	[2]+[3]
[5]	Total Rate ($/kWh)	$0.15	$0.15	$0.15	[4]/([1]*1000)

	Actual Revenue Requirement and Revenue (dry year)				
		Class A	**Class B**	**Total**	**Calculation Notes**
[6]	Actual Sales (GWh)	**750**	**1,000**	**1,750**	Input
	Actual Costs				
[7]	*Actual Energy Marginal Cost ($000)*	*$37,500*	*$50,000*	*$87,500*	*[2]*[6]/[1]*
[8]	*Actual Other Marginal Cost ($000)*	*$50,000*	*$100,000*	*$150,000*	*[3]*
[9]	Actual Marginal Cost ($000)	$87,500	$150,000	$237,500	[7]+[8]
	Actual Revenues				
[10]	*Initial Revenue ($000)*	*$112,500*	*$150,000*	*$262,500*	*[5]*[6]*1000*
[11]	*Allocation of undercollection ($000)*	*-$8,333*	*-$16,667*	*-$25,000*	*Total: [9]-[10]; Class: Total*Class Sales/Total Sales*
[12]	Actual Total Revenue ($000)	$104,167	$133,333	$237,500	[10]+[11]
	Cross-Subsidization				
[13]	Revenues minus Costs ($000)	$16,667	-$16,667	$0	[12]-[9]
	Rate Impact				
[14]	Effective Rate, $/kWh	$0.14	$0.13	$0.14	[12]/([6]*1000)

[42] Input values (sales and initial revenue requirements) are shown in **blue**; other values are calculated. Key results are shown in red.

The first set of calculations in each table shows the initial revenue allocation and rate design process: PG&E's energy marginal cost revenue requirement is allocated between the two classes based on each class's share of forecasted sales, with other marginal costs calculated based on other factors. The total marginal cost revenue requirement for each class is divided by forecasted class sales to obtain the retail rate.

The second set of calculations evaluates the rate and revenue implications when actual sales for one customer class (Class A) deviate from the forecast, such as would be expected for the Agricultural class during a wetter or drier than normal year. In Table 5, under wetter conditions, the actual energy marginal cost for Class A is less than forecasted during the revenue allocation process (because less energy is required to meet Class A's load),[43] while other marginal costs remain unchanged.[44] Because rates are not adjusted for actual sales (and because rates in this example are 100% volumetric), total revenue, and not just the energy revenue, falls in proportion to the change in sales. As a result, the revenue reduction due to the change in Class A sales is greater than the cost reduction, and there is a revenue shortfall for this class.

Under current processes, this undercollection is recorded in the ERRA balancing account and spread among all customers in the following year or after an ERRA trigger

[43] For this simplified example, The Agricultural Parties ignore changes to energy marginal costs that might ensue due to load shape modifications that may accompany the load drop. These generally are secondary in magnitude and impact compared to the sales impacts.

[44] As noted above, the Agricultural Parties assume that only sales have varied from the initial forecast, not other marginal cost inputs (i.e., PCAFs, FLTs, or customer counts), consistent with observations from historic data, so other marginal costs for Class A are unchanged from the forecasted amounts. Similarly, marginal costs are unchanged for Class B because all marginal cost inputs are assumed to be the same as forecasted for this class.

filing,[45] so the total revenue is the sum of the initial revenue plus the allocation of the undercollection. The difference between the total revenue from a customer class and the class's cost allocation represents a subsidy to (or from) another customer class. Under wet conditions, the revenue collected is less than the marginal cost for Class A; the opposite is true for Class B (see row 13 in Table 5).

When this same calculation, shown in Table 6, is done for the scenario in which Class A loads are *higher* than forecasted during the initial revenue allocation and rate design process, as would typically occur during drought conditions for the Agricultural class, the revenue collected for Class A is greater than the class's marginal cost, and the opposite is true for Class B.

Two major lessons can be learned from this illustrative calculation:

1. All else equal, a reduction in one class's sales below the forecasted amount will lead to an undercollection from that class; an increase in one class's sales above the forecasted amount will lead to an overcollection from that class.

2. Because ERRA balances are allocated to *all* customer classes, under- and overcollections from the class with the load variance spill over to affect the rates of the other rate classes.

This second point can be seen by comparing the rate for Class B across the three set of calculations, as shown in Table 7. In this example, underlying costs for Class B are unchanged from the initial revenue allocation and rate design, so the cost responsibility for Class B is the same as was calculated during those initial analyses, and the average rate paid by Class B customers should equal the rate of 15 cents per

[45] In this simplified example, the Agricultural Parties assume that the sales forecast used for the allocation of the undercollection is unchanged from the sales forecast that was used in the initial revenue allocation process and that the allocation is proportionate to sales without load shape influences.

kWh that was initially established. However, because of the variance between the Class A projected and actual sales, the actual average rate paid by Class B customers is (i) 17 cents per kWh in the scenario with low Class A sales and (ii) 13 cents per kWh in the scenario with high Class A sales. In other words, in years in which Class A underpays their revenue responsibility (high water year), other customer classes make up this revenue shortfall with higher than their fair share of rates, and in years in which Class A overpays their revenue responsibility (low water year), other customer classes benefit with rates that are lower than their fair share of rates.[46]

Table 7: Impact of Class A Sales on Class B Rates[47]

	Class A Rate (c/kWh)	Class B Rate (c/kWh)	Class B Rate Change Due to Class A Sales Variance
Initial Rate	15.0	15.0	N/A
Actual with Low Class A Sales	18.3	16.7	11%
Actual with High Class A Sales	13.9	13.3	-11%

C. REVENUE IMPLICATIONS OF SALES FORECAST ERRORS - ASSESSMENT FROM 2017 GRC MODEL (WITNESS: R. MCCANN)

The simplified illustrations provided above are useful for understanding how sales forecast errors result in revenue distortions for all customer classes. However, PG&E's actual revenue allocation and rate design processes are more complex than depicted in those illustrations. To assess the magnitude of the revenue distortions from PG&E's revenue allocation and rate design processes, the Agricultural Parties therefore ran PG&E's 2017 GRC revenue allocation model under normal, high-water, and low-water

[46] To be more precise, rate effects for other customers happens in the year following the Class A over- or underpayment, unless there is a mid-year ERRA trigger adjustment.
[47] See Table 5 and Table 6, rows 5 and 14.

conditions (holding all assumptions constant except for the level of agricultural sales). The results of this analysis are summarized in Table 8, which shows how the following elements vary when there is a change from normal water conditions:

1. Agricultural sales (Line 3), calculated to reflect average historic variations in sales with changes in water conditions;[48]
2. PG&E's agricultural revenue requirement,[49] based on the change in marginal generation energy costs due to the change in sales (Line 4 and Line 6); and
3. Agricultural sales revenues (Line 7), obtained by applying the change in sales to the average rate derived from a normal-year forecast.

The table also shows how the changes in agricultural revenue requirements under wet and dry conditions compare to the changes in agricultural sales revenue (Line 8) and how these under- or overcollection will affect system-average rates when they are included in revenue requirements in the following year (Line 9).

Table 8: Changes to Revenues and Costs with Different Hydrologic Conditions
values shown represent the change from normal water-year conditions

Line	Differences from Normal Year				
1	Water Year Type	Wet Year	Normal Year	Dry Year	Weighted Average
2	Water Year Weights	31%	20%	49%	
3	Agricultural Sales (GWh)	(683)	0	637	95
4	Marginal Generation Costs ($Mil)	($16)	$0	$15	$2
5	**Differences from Normal Year ($Mil)**				
6	Agricultural Revenue Requirements	($16)	$0	$15	*$2*
7	Agricultural Sales Revenues	($142)	$0	$133	*$20*
8	RRQ - Sales Revenues	($126)	$0	$117	$17
9	*System Average Rate Next Year*	*$0.0015*	*$0.0000*	*($0.0014)*	*($0.0002)*

[48] See Appendix A for a description of the methodology that was used to calculate the average historic variations in sales with changes in water conditions.
[49] The agricultural and system revenue requirement changes are identical, holding all else equal.

Finally, the table shows the probability of wet, normal and dry conditions in each year (Line 2), based on conditions in California over the last 35 years. During this time, California had dry conditions in about half of the years and wet conditions in only 30% of the years.[50] These water year weights are used to calculate the weighted averages in the rightmost column.

As indicated in the table, the swings in costs to agricultural customers in wet and dry years are much larger than the changes in underlying costs. For example, in the dry year shown on Line 7, agricultural sales revenue increases $133 million, while costs rise only $15 million; PG&E therefore overcollects by $117 million that year. Likewise, in the wet year, PG&E undercollects by $126 million (compared to the initial revenue allocation). Based on the historic hydrologic trace for the last 35 years, in which dry years significantly exceeded wet years, the weighted annual average overcollection is $17 million above costs, as shown in Line 8.

These over- and undercollections affect all rate classes. Line 9 shows that the impact on average system rates in the next year, when the over- and undercollections are incorporated into rates, can be an increase of $0.0015 per kilowatt-hour (kWh) after a typical wet year or a reduction of $0.0014 per kWh after a typical dry year, due to variances in agricultural revenues. In years in which the agricultural sales forecast error is greater than the typical year values shown in Line 2, the rate impacts for all customers would likely be greater.

[50] Wet, normal and dry years are defined using the California Department of Water Resources' Sacramento River Runoff Index. Wet years tend to be punctuations (e.g., 1983, 1998, 2006, 2011) in a stretch of moderately dry years, while droughts tend to stretch on for many years (e.g., 1987-1994, 2012-2016). (California Department of Water Resources, "California Data Exchange Center," http://cdec.water.ca.gov/cgi-progs/iodir/WSIHIST, retrieved January 2017. (See Attachment I))

One of the key features of this analysis is that cost drivers other than sales do not vary with water availability, consistent with trends found in historic agricultural load data provided by PG&E.[51] The number of customers does not vary based on water-year type, and the distribution and generation systems are already planned based on a 1-in-10-year extreme condition that accounts for hydrologic variability; none of those marginal costs are affected by short-term changes in water conditions. Thus, PG&E is left with changes only to generation energy marginal costs. Yet, the PCAF and FLT forecast methodology used in PG&E's Study incorrectly assumed that PCAFs and FLTs (and therefore, generation and distribution capacity cost responsibility) scale with changes to sales. Analysis with PG&E's revenue allocation model in this proceeding shows that such methods misallocate costs to agricultural customers by an average of about ±$40 million during dry and wet years. PG&E included such misallocations in its Study results,[52] which is a significant problem with PG&E's Study.

1. Using the Current Revenue Allocation Method Compounds the Impact on Agricultural Customers over Multiple Years

The analysis shown in Table 8 provides an assessment of revenue misallocations from a single year. Whether these misallocations will start to balance out the following year or grow larger will depend on whether the water-year type shifts or stays the same. The last 35 years of California precipitation history indicate that a wet year is more likely to follow a wet year, and a dry year is more likely to follow a dry year. For example, a

[51] See footnotes 36 - 38.

[52] Actual amounts of the misallocations in PG&E's Study are likely greater than this amount because the sales forecast error during the 2012-2014 dry years included in the Study period averaged about 1,600 GWh per year (see PG&E-08, Vol 2, Appendix F Attachment 4, Table 1), which is more than double the 637 GWh sales forecast error used for the dry scenario in this analysis (Table 8, line 3).

dry year follows a dry year 63% of the time; a wet year follows a wet one 55% of the time.[53] As a result, misallocations tend to be compounded.

Table 9 calculates the overcollections or undercollections that, on average, will ensue in the year after a wet year, normal year, or dry year based on the probabilities of each water-year type occurring. For example, since a wet year is most likely to follow a wet year, but a dry year is also possible, the expected value of the undercollections in a year following a wet year is less than the undercollections from a wet year ($37 million, as compared to the $126 million undercollection from Table 8). The present value of the first and second year under- or overcollections are shown in the bottom section of the table, and the weighted average results for the wet year, dry year, and normal year scenarios are shown in the rightmost column.

There are two main findings from this analysis:

1. Since wet years tend to follow wet years, and dry years tend to follow dry years, in the short-term there is likely to be a growing accumulation of under- or overcollections. (This can be seen in that the two-year under- or overcollections in Row 16 of Table 9 are greater than the one-year under- or overcollections in Row 8 of Table 8.) In other words, multi-year stretches in which agricultural customers consistently underpay or overpay compared to their original revenue allocation are typical. For example, the expected value of overpayments from a two-year period starting with a dry year is $171 million (Row 16).

2. While there may be wet spells in the mix, since dry years are more common overall than wet years, over longer-term periods, overpayments exceed underpayments. On an expected value basis, overpayments from a two-year period are $34 million (Row 16).

[53] Calculated from the California Department of Water Resources' Sacramento River Runoff Index. (California Department of Water Resources, "California Data Exchange Center," http://cdec.water.ca.gov/cgi-progs/iodir/WSIHIST, retrieved January 2017. (See Attachment I))

In other words, in the short-term and over the long-run, rather than self-correcting, the revenue distortions tend to grow over time.

Table 9: Revenue Distortions over a Two-Year Period

Line	Differences from Normal Year				
1	Water Year Type	Wet Year	Normal Year	Dry Year	Weighted Average
2	Probability 2nd Year will be:				
3	*Wet Year*	*55%*	*29%*	*19%*	
4	*Normal Year*	*18%*	*29%*	*19%*	
5	*Dry Year*	*27%*	*43%*	*63%*	
6	Differences from Normal Year, 2nd Year				
7	Agricultural Revenue Requirements	($5)	$2	$6	$2
8	Agricultural Sales Revenues	($41)	$16	$56	$18
10	*RRQ - Sales Revenues*	($37)	$14	$50	$16
12	PV of Cumulative Two-Year Difference				
13	Agricultural Revenue Requirements	($21)	$2	$22	$4
14	Agricultural Sales Revenues	($186)	$17	$193	$39
16	*RRQ - Sales Revenues*	($165)	$15	$171	$34

V. CONCLUSIONS AND RECOMMENDATIONS

The Agricultural Parties have demonstrated in this testimony that the current ratemaking process results in revenue distortions when actual water-year conditions differ from the "normal" conditions assumed in PG&E's sales forecasts. Dry years can result in significant overcollections from agricultural customers and revenue reductions for other customers, with the opposite true in wet years. Based on the evidence presented in this proceeding, the Commission should explicitly acknowledge this flaw in PG&E's current revenue allocation methodology.

The Agricultural Parties presented analyses of this issue in past GRCs, and advocated that it be effectively addressed.[54] As part of the marginal cost and revenue allocation settlement in PG&E's 2014 GRC Phase II proceeding, PG&E agreed to a workshop process to examine this issue,[55] but the Study that PG&E provided is so full of methodological and data flaws as to be unusable.[56] Meanwhile, California has experienced one of the worst droughts in state history, causing substantial increases in agricultural load and severe overcollections from these customers, and we are no closer to a remedy than we were three years ago.

As a first step to developing a remedy, there needs to be a reasonable understanding of the extent of past overcollections (or undercollections) and how these should be calculated. With this understanding in place, the Agricultural Parties and other parties can work to develop a mechanism to reduce these structural revenue distortions on an ongoing basis in the future. Commission policy allows for bill errors to be corrected for up to three years.[57] Given this policy, and that the Agricultural Parties have been working to correct this issue for many years, we request that PG&E work with the Agricultural Parties to quantify the cost shift to and from agricultural customers back to 2014.

One of the flaws of PG&E's Study is that it assumed that the fluctuations to Agricultural class sales with changing hydrological conditions would be matched by

[54] See, for example, "Prepared Direct Testimony Of Richard McCann, Ph.D on Marginal Costs, Revenue Allocation, and Rate Design Issues on Behalf of the Agricultural Energy Consumers Association," A.13-04-012, December 13, 2013, pages 21-24.
[55] 2014 PG&E Settlement Agreement, pages 15-16.
[56] See discussion in Section III.
[57] PG&E. Electric Rule No. 17.1, Sheet 2

fluctuations to Agricultural class peak loads. As demonstrated in this testimony based on an analysis of PG&E's historic load and sales data for the Agricultural class, this is not the case.[58] As a result, the calculation of cost shifts can be narrowed to reflect that only agricultural marginal energy costs change in response to varying hydrological conditions, with other marginal cost components not changing in a predictable manner.

Based on these conclusions and on the analysis provided in this testimony, the Agricultural Parties respectfully request that the Commission make the following findings, conclusions, and orders:

1. On account of significant year-to-year variability in Agricultural class sales, PG&E's sales forecast error for the class has been substantially more extreme than for other customer classes, with forecast errors of 30 to 40% in recent years.

2. Agricultural sales forecast errors result in revenue distortions for all customers, but particularly for the Agricultural class. Dry years tend to result in overcollections from agricultural customers and revenue reductions for other customers, with the opposite true in wet years.

3. Given the extreme drought in California between 2012 and 2016, the evidence strongly suggests that there have been significant overcollections from the Agricultural class in recent years, which may be partially offset by undercollections during the 2017 wet year.

4. An assessment of the extent of these overcollections and undercollections can be made by evaluating changes only to marginal energy costs under varying hydrological condition since, per PG&E's data, marginal capacity costs and marginal customer costs do not predictably vary with changing hydrological conditions.

5. PG&E is directed to work cooperatively with the Agricultural Parties during the period prior to the filing of PG&E's next GRC Phase II proceeding to quantify annual cost shifts to and from the Agricultural class back to 2014. As part of this effort, PG&E is directed to respond to Agricultural Parties' discovery requests concerning these matters throughout this period.

[58] See footnotes 36-38 and surrounding discussion; see also the paragraph preceding Section IV.3.i.

APPENDIX A: CALCULATION OF THE VARIATION IN AGRICULTURAL CLASS SALES WITH WATER CONDITIONS (WITNESS: R. MCCANN)

PG&E's sales forecast model does not appropriately reflect the variability of sales with water conditions, showing a swing in agricultural sales of only 3.2% in either direction between normal conditions and wet or dry conditions, while historic sales data shown in Table 2 show much greater variability. The reason for the poor performance of PG&E's agricultural sales model arises from the use of several inappropriate explanatory variables, as summarized in Table 10 and discussed below.

In order to calculate the variation in Agricultural class sales during a typical wet year or dry year, the Agricultural Parties modified PG&E's sales forecast in three ways so that it better reflects the variability of agricultural sales with water conditions:

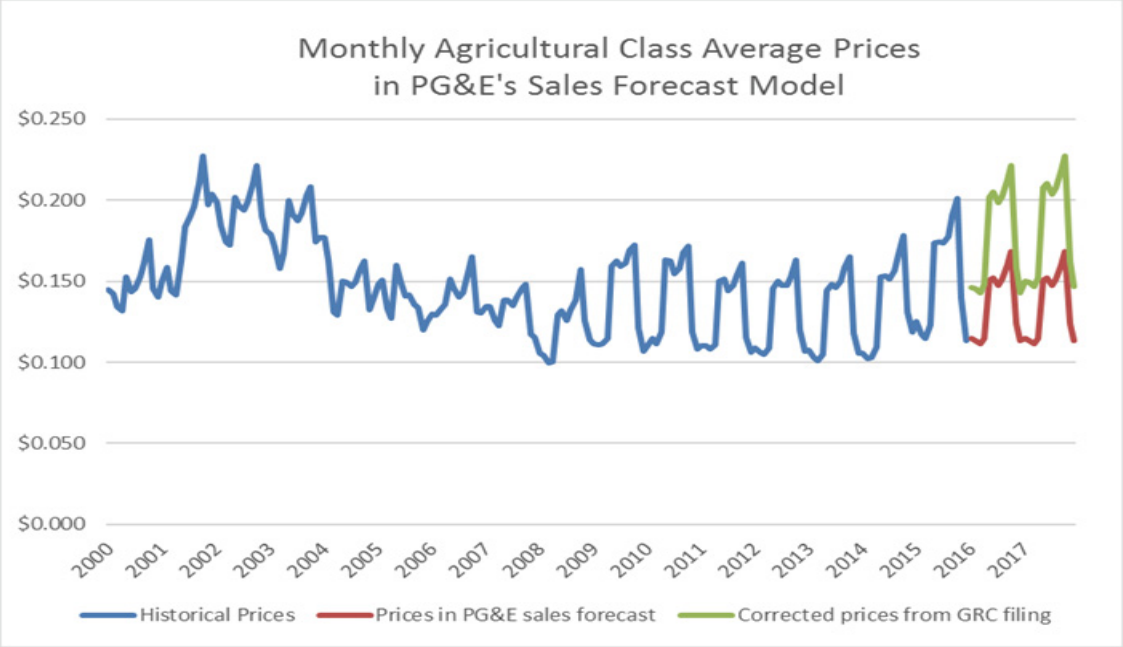
1. PG&E's use of the value of agricultural output as a variable in the sales model is problematic because the value of agricultural output does not correlate well with changes to water consumption or energy use as it reflects, in part, changes in prices as well as modifications from lower to higher value crops. Furthermore, the values PG&E used for this output variable, which come from a proprietary dataset from Moody's Analytics, show a decrease in agricultural output since 2010, a phenomenon that is not supported by any other industry information. According to the U.S. Department of Agriculture, California's agricultural output rose steadily until it peaked in 2014.[59] The unexplained decrease in agricultural output in PG&E's model suppresses agricultural sales forecasts since 2010. The Agricultural Parties replaced this variable with the number of agricultural accounts, which is a better indicator of growth in energy use.

2. Most of the predictive power in PG&E's model is embodied in the 1-, 2-, and 12-month lagged sales variables. Better explanatory variables are a yearly trend to capture long-term changes in energy use, and a one-month autoregression (AR(1)) term to correct for serial correlation in the error terms. Leaving out the lagged variables allows for more of the sales variation to be explained by hydrologic factors, a primary driver of agricultural energy use.

[59] USDA Economic Research Service, "Farm and Wealth Statistics," https://www.ers.usda.gov/data-products/farm-income-and-wealth-statistics.aspx, Retrieved January 2017. (Statistics from the U.S. Bureau of Economic Analysis show similar, but not identical, data to the USDA data.)

3. The Agricultural Parties agree that agricultural energy prices should remain as a variable in the model; however, PG&E's price series is incorrect. PG&E's series shows the average agricultural price decreasing from $0.15206 per kWh in 2015 to $0.13512 per kWh in 2016 and 2017. Yet, according to PG&E's 2017 GRC revenue allocation model, the average agricultural rate is estimated at $.01818 per kWh in 2017, and, as stated in PG&E's testimony, this is a 0.4% increase over 2016. Further, the monthly price forecast used in PG&E's sales model is incongruous with historical agricultural rates included in PG&E's model. This is illustrated in Figure 1, which also illustrates that the rates from PG&E's revenue allocation model are relatively consistent with (though a bit higher than) historical rates. As a result, the Agricultural Parties replaced the price series in PG&E's sales forecast model with prices that are consistent with PG&E's revenue allocation model.

Figure 1 Historic and Forecasted PG&E Agricultural Rates[60]



[60] To develop monthly rates from the 2016 and 2017 annual average rates in PG&E's revenue allocation model, the monthly rates from PG&E's sales forecast model were scaled upward to match the revenue allocation model rates on an annual average basis.

Table 10: Corrections to PG&E's Agricultural Sales Forecast Model

PG&E Variables	Agricultural Parties Variables	Reasoning for Keeping or Changing PG&E Variables
Log of Real Price	Log of Real Price	Used to capture price effects on energy use; corrected to reflect PG&E's retail prices
Log of Ag Output	*(Dropped)*	The value of Ag output is not a good indicator of water or energy use in agricultural production. In the case of expansion of productive farmland, output would show a positive relationship with energy use; in a situation in which crop types are changed, the relationship could be positive or negative. Instead of this variable, the number of agricultural accounts is used as an explanatory variable to account for growth in the agricultural sector.
1-Month Lagged Log Sales	(See AR(1) below)	PG&E includes lag terms to correct for serial correlation. However, including 1-, 2-, and 12-month lags to correct for correlation in the error terms is not justified, and may result in biased estimators. Instead, autocorrelation was corrected by including an AR(1) term.
2-Months Lagged Log Sales	*(Dropped)*	
12-Months Lagged Log Sales	(Dropped)	
Rainfall	Rainfall	Used as climate indicators
Drought Index	Drought Index	
Cooling Degree Days	Cooling Degree Days	
Month Dummy Variables	Month Dummy Variables	Used to account for the seasonal aspects of water and energy use in agriculture
	Year	Used to capture long-term trends in energy use
	Log of Agricultural Accounts	Used to account for the size of the agricultural sector that is dependent on PG&E at any given time. This is a better indicator of sector size than agricultural output, as explained above.
	AR(1)	Autoregressive term, used to correct for serial correlation in error terms in place of lag terms

Table of Attachments

Attachment A: Resume and Statement of Qualifications of Richard McCann Laura Norin

Attachment B: PG&E Responses to California Farm Bureau Federation Data Requests

This attachment includes the following data request responses: DR04Q1, DR04Q2, DR04Q3, DR05Q1, DR06Q1

Attachment C: Settlement Agreement on Marginal Cost and Revenue Allocation in Phase II of Pacific Gas and Electric Company's 2014 General Rate Case

Attachment D: Irrigation Training and Research Center, "California Agricultural Electrical Energy Requirements," Prepared for the California Energy Commission PIER Program

Attachment E: Tulare County Cooperative Extension, "Energy and Cost Required to Lift or Pressurize Water"

Attachment F: Fallowed Area Mapping for Drought Impact Reporting: 2015 Assessment of Conditions in the California Central Valley

Attachment G: California Department of Water Resources. SWPAO Water Deliveries, Notices to State Water Contractors

Attachment H: U.S. Bureau of Reclamation. "Summary of Water Supply Allocations"

Attachment I: California Department of Water Resources Sacramento River Runoff Index

Attachment A: Resume and Statement of Qualifications of Richard McCann Laura Norin

STATEMENT OF QUALIFICATIONS OF LAURA B. NORIN

Q. Please state your name and business address.

A. My name is Laura Norin. I am a Senior Project Manager with MRW & Associates, LLC ("MRW"). MRW is an energy consulting firm that was founded in 1986. MRW specializes in power and gas market assessments, regulatory matters, litigation support, expert witness testimony, contract review, and negotiations. My business address is 1814 Franklin Street, Suite 720, Oakland, California.

Q. Briefly summarize your educational background and professional experience.

A. Since 2004 I have been working at MRW where I have been focusing on California's electricity and natural gas markets, regulations, and policies. During this time, I have worked with energy policy makers, financial institutions, energy suppliers, and municipal and industrial end-users on a variety of issues, including electricity ratemaking, departing load exit fees, asset valuation, and wholesale and retail electricity price forecasting. Previously, I worked as a research associate at Lawrence Berkeley National Lab's Environmental Energy Technology Division. I have a Masters Degree in Applied Physics from the University of California, Berkeley.

Q. Have you ever testified before this Commission?

A. Yes. A list of prepared testimony follows my resume.

Q. For whom are you submitting this testimony?

A. I am submitting this testimony of behalf of the California Farm Bureau Federation.

RESUME OF LAURA B. NORIN

PROFESSIONAL EXPERIENCE

Senior Project Manager
MRW & Associates, LLC
(2004-Present)
Conduct quantitative and qualitative analyses related to energy regulation, policy, commerce, and litigation. Research and develop policy reports and participate in regulatory proceedings. Prepare expert witness testimony in utility rate cases and other proceedings before the California Public Utilities Commission. Construct models to forecast retail electricity rates and assess generation alternatives. Major projects include work on nuclear energy policy, retail energy markets, natural gas storage, and resource adequacy.

Graduate Student Researcher
UC-Berkeley
(2002-2004)
Conducted biophysics research related to cellular interaction mechanisms.

Research Associate
Lawrence Berkeley National Lab
(2001-2002)
Used microscopic and spectroscopic techniques to investigate the sources of battery failure in high-power batteries being developed for hybrid vehicles.

Research Assistant
Fieldston Company
(1996)
Conducted research and quantitative analysis related to domestic energy transportation. A major project involved analyzing the finances of domestic freight railroads as part of a study on the effects of railroad consolidation on deregulating utilities.

EDUCATION

M.S., Applied Physics, University of California, Berkeley, 2004
B.S., Physics, University of California, Berkeley, 2001

Prepared Testimony of Laura B. Norin

1. CPUC Application 09-12-020
   Direct Testimony of South San Joaquin Irrigation District Concerning PG&E's 2011 General Rate Case Phase 1 Application (with Steven C. McClary). May 19, 2010.

2. CPUC Application 10-03-014
   Direct Testimony of Laura Norin on Behalf of South San Joaquin Irrigation District Concerning PG&E's 2011 General Rate Case Phase II Application. October 6, 2010.

3. CPUC Application 10-12-005
   Testimony of Steven McClary and Laura Norin on Behalf of UCAN Concerning SDG&E's General Rate Case. September 22, 2011.

4. CPUC Application 11-05-023
   Testimony of Laura Norin on Behalf of UCAN Concerning SDG&E's Application for Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center and Quail Brush Power. September 23, 2011.

5. CPUC Rulemaking 11-03-012
   Proposal of Laura B. Norin on Behalf of the California Farm Bureau Federation, the Agricultural Council of California, the California League of Food Processors, and the Agricultural Energy Consumers Association (the "Agricultural Parties") Concerning the Allocation and Use of Greenhouse Gas Allowance Auction Revenues. January 6, 2012.

6. CPUC Application 11-06-007
   Testimony of Laura Norin on Behalf of the Coalition for Affordable Street Lights Concerning SCE's Proposed Street Light Rates. February 6, 2012.

7. CPUC Application 11-10-002
   Testimony of Steven McClary and Laura Norin on Behalf of San Diego Consumers' Action Network (SDCAN) Concerning SDG&E's General Rate Case Phase II. June 12, 2012.

8. CPUC Application 13-08-002 *et al*
   Testimony of Laura Norin on Behalf of the California Farm Bureau Federation Concerning the Investor-owned Utilities' Greenhouse Gas Implementation Plans. October 9, 2013.

9. CPUC Application 13-08-004
   Testimony of Laura Norin on Behalf of the Public Agency Coalition Concerning SCE's Undercollection Tracking. November 20, 2013.

10. CPUC Application 13-04-012
Testimony of Laura Norin on Behalf of the California Farm Bureau Federation Concerning PG&E's Marginal Cost Studies and Agricultural Rate Deign Proposals. December 13, 2013.

11. CPUC Application 13-11-003
Testimony of Laura Norin on Behalf of the Coalition for Affordable Street Lights (CASL) Concerning SCE's Street Light-Related Revenue Request. August 18, 2014.

12. CPUC Application 14-05-024
Direct Testimony of Agricultural Energy Consumers Association and the California Farm Bureau Federation. August 22, 2014.

13. CPUC Application 14-01-027
Testimony of Laura Norin on Behalf of the California Farm Bureau Federation Concerning SDG&E's Rate Design Window Proposals. November 14, 2014.

14. CPUC Application 14-01-027
Rebuttal Testimony of Laura Norin on Behalf of the California Farm Bureau Federation Concerning SDG&E's Rate Design Window Proposals. December 12, 2014.

15. CPUC Application 14-06-014
Testimony of Laura Norin on Behalf of the California Farm Bureau Federation Concerning SCE's 2015 General Rate Case Phase 2 Application. March 13, 2015.

16. CPUC Application 14-11-003
Testimony of Briana Kobor, Laura Norin, and Mark Fulmer on Behalf of the Utility Consumers' Action Network Concerning Sempra's Revenue Requirement Proposals for SDG&E and SoCal Gas. May 15, 2015.

17. CPUC Application 14-12-007
Testimony of Mark Fulmer and Laura Norin on Behalf of the Utility Consumers' Action Network Concerning Risk Assignment of SONGS Decommissioning Costs. July 15, 2015.

18. CPUC Application 14-12-007
Rebuttal Testimony of Mark Fulmer and Laura Norin on Behalf of the Utility Consumers' Action Network Concerning Risk Assignment of SONGS Decommissioning Costs. August 3, 2015.

19. CPUC Application 15-09-001
Prepared Testimony of Laura Norin and Brandon Charles on Behalf of South San Joaquin Irrigation District. April 29, 2016.

20. CPUC Application 15-09-001
Rebuttal Testimony of Laura Norin on Behalf of South San Joaquin Irrigation District. May 27, 2016.

21. CPUC Application 15-04-012
Testimony of Laura Norin and Brandon Charles on Behalf of the California Farm Bureau Federation Concerning San Diego Gas& Electric's 2016 General Rate Case Phase 2 Application. July 5, 2016.

Attachment B: PG&E Responses to California Farm Bureau Federation Data Requests

This attachment includes the following data request responses: DR04Q1, DR04Q2, DR04Q3, DR05Q1, DR06Q1

PACIFIC GAS AND ELECTRIC COMPANY
2017 General Rate Case Phase II
Application 16-06-013
Data Response

PG&E Data Request No.:	CFBF_004-Q01		
PG&E File Name:	GRC-2017-PhII_DR_CFBF_004-Q01		
Request Date:	January 4, 2017	Requester DR No.:	004
Date Sent:	January 30, 2017	Requesting Party:	California Farm Bureau Federation
PG&E Witness:	Tysen Streib	Requester:	Karen Mills

QUESTION 1

The table below provides total agricultural sales (GWh) as shown in three PG&E datasets:

- Dataset A: "Sales Customer Forecast versus Actuals 10 Years.xlsx" (in workpapers to Appendix F Ag Balancing Account Study, folder "Workpapers - Sales and Total Rate Variance"), sheet "Sales Annual," column E (converted to GWh)
- Dataset B: "Attachments 5_6_7_Corrected_p.xlsx" (in workpapers to Appendix F Ag Balancing Account Study, top-level folder). Retail sales: sheet "2014 DistMC Summary," column C; bundled sales: sheet "2014 GenMC Summary," column C
- Dataset C: PG&E response to CFBF Data Request 3 Q 2, Attachment 1, sheet "2C," column C (converted to GWh)

Table 1: Agricultural Electric Sales (GWh)

	Dataset A	Dataset B		Dataset C
		Retail	Bundled	
2003	3,830			
2004	4,283			
2005	3,731			
2006	3,880			
2007	5,190			
2008	5,582			
2009	5,816			

2010	5,019			
2011	4,733	4,691	4,654	
2012	6,162	6,179	6,140	
2013	6,331	7,022	6,984	7,070
2014		7,611	7,582	7,528
2015				7,618

a) Please specify whether the sales shown in Dataset A and Dataset C are retail or bundled sales.

b) Please explain why the sales shown in Dataset A for 2011-2013 do not match those shown in Dataset B or, for 2013, those shown in Dataset C.

c) Please explain why the sales shown in Dataset B for 2013-2014 do not match those shown in Dataset C.

d) Please provide total agricultural bundled and retail electric sales in each year from 1995-2016. If there are any differences between these amounts and the amounts shown in file "Table 1.xlsx" (in workpapers to Appendix F Ag Balancing Account Study, folder "Workpapers - Sales and Total Rate Variance"), column E, please explain.

ANSWER 1

a) Datasets A and C both represent total retail sales (Bundled, Direct Access and Community Choice Aggregation). However, Dataset A was a draft set of historical values that only included data through October of 2013. It was inadvertently included in workpapers and was not used for any analysis, revenue allocation, or rate design.

b) Datasets B and C were collected using slightly different logic in the definition of agricultural accounts and/or time periods. It would take considerable effort to identify and quantify the exact differences in methods, but the variations include:

- Datasets may have different rules for handling inactive accounts or customers that transferred into or out of the agricultural class mid-year.
- Datasets may have been queried at different times. For example, recorded data for 2013 may have been queried in February 2014 and saved the data at that time. A different dataset could have queried the same period years later and reflect back-billing, refunds, or other adjustments.

- Datasets may qualify agricultural customers by their Revenue Account or their Rate Class, which might not always be the same. For example:
    - Datasets may have different rules for classifying agricultural customers in other revenue accounts such as Public Authority.
    - Datasets may have different rules for handling Standby customers.
- Since monthly billing cycles don't match up perfectly with calendar months, some datasets assign a customer's bill to the month and year that had a majority of the days in the billing cycle. Alternatively, sales could be categorized in the month and year that the bill was issued – potentially in the year after the electricity was consumed.

c) See the answer to part b.

d) Below are the bundled sales from 2003 to 2015 and retail sales from 1998 to 2016. These sales align with the values in Dataset B and "Table 1.xlsx".

Year	Retail	Bundled
1998	3,069	
1999	3,739	
2000	3,818	
2001	4,150	
2002	3,930	
2003	3,916	3,887
2004	4,305	4,227
2005	3,745	3,671
2006	3,843	3,798
2007	5,405	5,386
2008	5,596	5,577
2009	5,803	5,786
2010	5,070	5,050
2011	4,691	4,654
2012	6,179	6,140
2013	7,022	6,984
2014	7,611	7,582
2015	7,657	7,569
2016	6,760	

PACIFIC GAS AND ELECTRIC COMPANY
2017 General Rate Case Phase II
Application 16-06-013
Data Response

PG&E Data Request No.:	CFBF_004-Q02		
PG&E File Name:	GRC-2017-PhII_DR_CFBF_004-Q02		
Request Date:	January 4, 2017	Requester DR No.:	004
Date Sent:	January 30, 2017	Requesting Party:	California Farm Bureau Federation
PG&E Witness:	Tysen Streib	Requester:	Karen Mills

QUESTION 2

The table below shows the annual average number of agricultural customer accounts per three PG&E datasets:

- Dataset A: "Sales Customer Forecast versus Actuals 10 Years.xlsx" (in workpapers to Appendix F Ag Balancing Account Study, folder “Workpapers - Sales and Total Rate Variance”), sheet “Customers Annual,” column E (total customer-months divided by 12 to obtain annual average customer accounts shown in the table)
- Dataset B: "Attachments 5_6_7_Corrected_p.xlsx" (in workpapers to Appendix F Ag Balancing Account Study, top-level folder), sheet “2014 DistMC Summary,” column M (total customer-months divided by 12 to obtain annual average customer accounts shown in the table)
- Dataset C: PG&E response to CFBF Data Request 3 Q 2, Attachment 1, sheet “2A,” column C

Table 1: Agricultural Electric Accounts

	Dataset A	Dataset B	Dataset C
2003	81,029		
2004	79,886		
2005	79,097		
2006	79,331		
2007	80,644		
2008	81,956		
2009	83,639		

2010	83,812		
2011	84,133	84,133	
2012	85,628	85,628	
2013	72,245	85,541	133,361
2014		86,806	106,518
2015			109,376

a) Please explain the differences between the customer account numbers for 2013 shown in each of the three datasets.

b) Please explain the significant difference between the customer account numbers shown in Dataset C and the customer account numbers shown in the other datasets.

c) Please provide the annual average number of agricultural electric accounts in each year from 1995-2016.

ANSWER 2

a) During investigation into this data request, PG&E discovered dataset C provided in response to CFBF_003-Q02 was incorrect. The text incorrectly stated that PG&E used customer rate schedule as of December, and then back cast as though each customer had only been on that December rate schedule all year, in the prior 11 months. Instead, PG&E inadvertently did not apply that December rate schedule screen. As a result, PG&E inadvertently captured all intra-year rate schedule migration activity by individual customers, often double-counting the same customer or meter site within the same calendar year. This was primarily due to the following factors:

- Default TOU activity, in which AG-1A and AG-1B customers in January and February migrated to AG-4A and AG-4B in March.
- Voluntary rate schedule migration, such as when a grower may decide to switch many of his current AG-5B meter sites to AG-4B, based on analysis as he was approaching the growing season, and planning lower irrigation volumes than in prior years.
- PG&E interval meter installations which change the SAID (Service Agreement ID) for a given meter site, or other reasons an SAID might change, such as a change in meter reading route.
- The SAID changed due to a change of party, new ownership, or new account title holder on the meter site, among others.

In addition, the customer counts for dataset A were low for 2013 because the reported number of customer months only included data through October 2013, as described in the answer to Question 1, part a.

b) See the answer to part a.

c) Below is a table showing the average number of monthly bills in Revenue Account 354 (Agricultural) from 2003 to 2016.

Year	Average Monthly Bills
2003	81,029
2004	79,886
2005	79,097
2006	79,331
2007	80,644
2008	81,956
2009	83,639
2010	83,812
2011	84,133
2012	85,628
2013	85,541
2014	86,825
2015	88,016
2016	88,668

PACIFIC GAS AND ELECTRIC COMPANY
2017 General Rate Case Phase II
Application 16-06-013
Data Response

PG&E Data Request No.:	CFBF_004-Q03		
PG&E File Name:	GRC-2017-PhII_DR_CFBF_004-Q03		
Request Date:	January 4, 2017	Requester DR No.:	004
Date Sent:	January 30, 2017	Requesting Party:	California Farm Bureau Federation
PG&E Witness:	Tysen Streib	Requester:	Karen Mills

QUESTION 3

PG&E workpaper "Attachments 5_6_7_Corrected_p.xlsx" (in workpapers to Appendix F Ag Balancing Account Study, top-level folder), provides actual agricultural generation and distribution PCAFs and FLTs in each of the years 2011-2014 (see sheet "2014 DistMC Summary," columns J and L, and sheet "2014 GenMC Summary," Column I)

a) Please identify the source of each year's data (e.g., load research data, smart meter data, etc.).

b) Please provide the list of peak intervals (i.e., peak hours or peak 15-minute intervals, as applicable) that are included in the generation and distribution PCAFs for each of the years 2011-2014.

c) Please provide actual agricultural generation and distribution PCAFs and FLTs consistent with those provided in this workpaper for each of the years 1995-2010, along with a list of the peak intervals included in each set of PCAFs. If PG&E is unable to provide data from each of these years, please provide the available data.

ANSWER 3

a) The data is from load research data for all years and includes SmartMeter data starting in 2012.

b) This data is provided in GRC-2017-PhII_DR_CFBF_004-Q03_Atch1.xlsx.

c) Confidential, provided pursuant to P.U Code Section 583, the California Public Records Act and the NDA for PG&E 2017 GRC II. This data response includes Proprietary and/or Confidential material exempt from disclosure to the public or third parties, including under the Public Records Act, and is being provided under the provisions of G.O. 66-C, Public Utilities Code Section 583, and as a trade secret pursuant to California Civil Code Sections 654, 655 and 3426- 3426.10 . In addition, certain material contains customer information that is confidential because does not meet the 15/15 aggregation requirements for protection of the privacy of non-residential customers and/or the 100/zip code aggregation requirement for protection of the privacy of residential customers under D.14-05-016 and other CPUC and California privacy rules and requirements.

The confidential file GRC-2017-PhII_DR_CFBF_004-Q03_Atch2_CONF.xlsx contains FLT data from 1999 to 2010.

The file GRC-2017-PhII_DR_CFBF_004-Q03_Atch3.xlsx contains distribution PCAFs from 1999 to 2010.

The file GRC-2017-PhII_DR_CFBF_004-Q03_Atch4.xlsx contains generation PCAFs from 2002 to 2010.

PACIFIC GAS AND ELECTRIC COMPANY
2017 General Rate Case Phase II
Application 16-06-013
Data Response

PG&E Data Request No.:	CFBF_005-Q01		
PG&E File Name:	GRC-2017-PhII_DR_CFBF_005-Q01		
Request Date:	January 9, 2017	Requester DR No.:	005
Date Sent:	January 17, 2017 (updated) February 3, 2017	Requesting Party:	California Farm Bureau Federation
PG&E Witness:	Amitava Dhar	Requester:	Karen Mills

QUESTION 1

Please provide total peak demand for each customer class, by division, in each year from 1995-2016. If PG&E is unable to provide data from each of these years, please provide the available data.

ANSWER 1

The attachments to this Data Response are Confidential, provided pursuant to P.U Code Section 583, the California Public Records Act and the NDA for PG&E 2017 GRC II. This data response includes Proprietary and/or Confidential material exempt from disclosure to the public or third parties, including under the Public Records Act, and is being provided under the provisions of G.O. 66-C, Public Utilities Code Section 583, and as a trade secret pursuant to California Civil Code Sections 654, 655 and 3426- 3426.10 . In addition, certain material contains customer information that is confidential because does not meet the 15/15 aggregation requirements for protection of the privacy of non-residential customers and/or the 100/zip code aggregation requirement for protection of the privacy of residential customers under D.14-05-016 and other CPUC and California privacy rules and requirements.

PG&E has data from 1999 through 2014, which are presented in the attached excel file "GRC-2017-PhII_DR_CFBF_005-Q01Atch01_CONF.xlsx". PG&E does not have requested FLT data available for the other years requested.

PACIFIC GAS AND ELECTRIC COMPANY
2017 General Rate Case Phase II
Application 16-06-013
Data Response

PG&E Data Request No.:	CFBF_006-Q01		
PG&E File Name:	GRC-2017-PhII_DR_CFBF_006-Q01		
Request Date:	January 30, 2017	Requester DR No.:	006
Date Sent:	February 15, 2017	Requesting Party:	California Farm Bureau Federation
PG&E Witness:	Amitava Dhar	Requester:	Karen Mills

QUESTION 1

PG&E's responses to DR 5 provided the same FLT data in response to our requests for both peak demand data (Q1) and non-coincident load data (Q2), but we were asking for two different sets of data. We can use the FLT data in response to Q2 (non-coincident load), but we'd like the generation PCAF data in response to Q1 (annual peak demand by class from 1995-2016, by division if available).

ANSWER 1

The generation PCAF data that PG&E currently has available only cover 2002 through 2015. Please find attached the data in file "GRC-2017-PhII_DR_CFBF_006-Q01 Atch01.xlsx".

Attachment C: Settlement Agreement on Marginal Cost and Revenue Allocation in Phase II of Pacific Gas and Electric Company's 2014 General Rate Case

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design. (U 39 M)	Application 13-04-012 (Filed April 18, 2013)

SETTLEMENT AGREEMENT ON MARGINAL COST AND REVENUE ALLOCATION IN PHASE II OF PACIFIC GAS AND ELECTRIC COMPANY'S 2014 GENERAL RATE CASE

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Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: July 16, 2014

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GRC Phase II decisions, the Settling Parties agree that the revenue allocation and rate design for that new revenue requirement category should be decided by the Commission at that time and that the rules governing existing revenue requirement categories presented in this settlement will not govern or be precedential for that purpose. Parties will be free to advocate whatever position the party deems appropriate for the new revenue requirement cost category at the time it is under consideration by the Commission.

n. CPUC Fee revenue requirement will be allocated on an equal cents per kWh basis and collected in distribution rates.

IX. WORKSHOPS AND STUDIES FOR THE 2017 GRC PHASE II

1. Agricultural Class Balancing Account Study

A balancing account or other mechanism that addresses the high level of sales variability and sales forecast uncertainty pertaining to the agricultural class, principally as a result of the unpredictability of the availability of surface water, will not be established as part of this Settlement. Instead, parties agree to pursue additional analyses to examine the desirability of such a balancing account, and the necessary components to develop it. Such analyses would review the year-to-year volatility of agricultural class revenues and sales versus other customer class revenues and sales, and include an assessment of possible over-collections of agricultural class revenue that accounts for variation in both PG&E's cost of service and revenues collected due to agricultural sales variability.

PG&E will compile an initial set of data based on input the parties provide to PG&E during the first quarter of 2015, and will provide that data to interested parties, to the extent feasible, for review at least two weeks prior to a workshop at which the data will be discussed. At the workshop, which is to be held no later than 9 months prior to the next GRC Phase II application deadline (and which may be held earlier), the parties will review the available data, provide input with regard to the required analysis, and establish a schedule for completion of the analysis and a workshop report. The schedule will set a date by which PG&E will complete and provide to all parties a report memorializing the analysis, which is targeted to be provided to

interested parties no later than 6 months prior to the filing of PG&E's next GRC Phase II application (and which may be provided earlier). The schedule will also include a second workshop at least two weeks following distribution of the report, at which parties will have the opportunity to ask questions about the report and discuss PG&E's analysis and conclusions. The schedule will afford parties an opportunity to provide their own evaluation of the analysis, to be transmitted to PG&E within 6 weeks of service of the initial report, such that evaluations by the parties can be included with the report. The parties envision the completion of the whole agricultural balancing account analysis process by no later than 4 months in advance of the deadline for PG&E's 2017 GRC Phase II application. The report will be included as a compliance item attached to PG&E's next GRC Phase II application.

2. Marginal Cost Workshops

The Settling Parties agree that PG&E will hold up to three workshops to address methodological issues pertaining to the development of marginal costs, including the issues that were raised by the Agricultural Parties and SBUA in this proceeding. Each such workshop would last not more than one day, and each would be noticed on all parties to the 2014 GRC Phase II and be open to all interested participants. Workshop discussions will include: consideration of customer and load growth forecasts; data issues; load diversity; customer access costs for small commercial customers (including variations in customer connection costs within the class); possible alternatives to distribution and customer access marginal cost; and additional topics pertaining to marginal cost calculations and methods for agricultural and other customers.

PG&E will schedule an initial planning conference call to be held within 4 months of the Commission's final decision in this proceeding. PG&E will notice this call on all parties at least 3 weeks prior to the date of the call. In the notice, parties will be asked to provide to PG&E a list of issues to be addressed as part of the workshop process at least one week prior to the call. PG&E will compile this list of potential workshop topics and will circulate the list to all parties to the 2014 GRC Phase II and any other party that has expressed interest. During the initial planning conference call, parties will refine the list of issues to be addressed as part of the final report and will establish a schedule for the workshops, including agenda items for each of the

Attachment D: Irrigation Training and Research Center, "California Agricultural Electrical Energy Requirements," Prepared for the California Energy Commission PIER Program

California Agricultural Water Electrical Energy Requirements

FINAL REPORT

December 2003

Prepared for

Public Interest Energy Research Program
Energy in Agriculture Program
California Energy Commission
1516 9th St.
Sacramento, CA 95814



by

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EXECUTIVE SUMMARY

The Irrigation Training and Research Center (ITRC) at Cal Poly State University, San Luis Obispo, conducted an analysis of the energy used to supply water to California's agriculture and examined potential future trends in the agriculture water community to predict future energy requirements.

A. Water Currently Destined for Agricultural Irrigation

Currently, energy use for agricultural water varies by location throughout the state. **Table 1** shows the current estimated electrical energy requirement by sector throughout the state. These estimates have been calculated by ITRC for a typical precipitation year. Explanations of how these estimates were made are found in the body of this report.

For this analysis the state was split into 13 zones based on the DWR ETo Zone Map. The numerical values for each zone are consistent with DWR values; however, some of the zones have been modified. **Figure 1** indicates the zones that have been used for this study. In the figure, all coastal zones (1,3,4) are shown collectively under Zone 3 to reduce clutter.

Table 1. Total electrical energy requirement for agricultural water destinations by sector throughout California for an average year

Modified DWR ETo Zone	Irrig. District Surface Water Pumping	Irrig. District Groundwater Pumping	On-Farm Groundwater Pumping	On-Farm Booster Pumping	Conveyance to Irrig. Districts	Total Electric Energy Use by Zone
	MWh/Year	MWh/Year	MWh/Year	MWh/Year	MWh/Year	MWh/Year
1	0	0	54,964	20,852		75,816
3	0	0	365,562	145,076		510,638
4	0	0	61,207	18,132		79,339
6	0	0	401,843	148,034		549,877
8	3,896	137	14,573	21,350		39,957
9	0	0	255,199	87,567		342,767
10	0	0	273,277	58,730		332,007
12a	26,171	27,051	283,381	300,329		636,932
12b	8,307	8,586	159,637	101,075		277,606
14	131,125	2,032	108,394	488,733	450,526	1,180,809
15	514,605	199,386	1,659,804	688,121	1,269,062	4,330,978
16	137,662	8,840	846,938	380,371		1,373,811
18	0	0	14,236	415,152		429,388
Total	**821,800**	**246,000**	**4,499,000**	**2,873,500**	**1,719,600**	

Total Ag. Irrig. Water Electrical Energy Usage	**10,159,900**	**MWh/Year**

Confidence Interval +/-	**10%**

Attachment E: Tulare County Cooperative Extension, “Energy and Cost Required to Lift or Pressurize Water"



Pub. IG6-96

Energy and Cost Required to Lift or Pressurize Water

Bill Peacock, Tulare County Farm Advisor

Power Requirements to Lift Water

It takes a lot of power to lift water. To appreciate how much, consider the following example.

> **Example:** A pump is discharging 452.5 gallons per minute. How much water is discharged in 12 hours and what is the weight of the water pumped during this period? One gallon weighs 8.3 pounds. The answers are: 325,851 gallons which happens to equal one acre-foot, and 2,719,226 pounds or 1,359 tons, which is the weight of one acre-foot of water.
>
> Calculated as follows:

1. 452.5 gallons per minute x 60 minutes per hour x 12 hours = 325,851 gallons

2. 325,851 gallons x 8.345 pounds per gallon = 2,719,226 pounds

> A pump discharging 450 gallons per minute is lifting 1.87 tons of water every minute.

The energy requirement increases with every foot the water is lifted. To determine the energy requirement, simply multiply the weight of water in pounds by the lift in feet: this calculates energy in units of foot-pounds (ft-lb).

> **Example:** How much energy does it take to lift an acre-foot of water (325,851 gallons) one foot in elevation? 100 feet in elevation? **The answers are: 2,719,226 ft-lbs and 271,922,600 ft-lb.**
>
> Calculated as follows:
> *Equation: Energy Required = weight of water x feet of lift*
>
> *Weight of one acre-foot = 325,851 gallons x 8.345 pounds per gallon = 2,719,226 pounds*

1) **Lift = 1 foot**
   Energy Required = 2,719,226 pounds of later x 1 foot of lift = 2,719,226 ft-lbs of energy

2) **Lift = 100 feet**
   Energy Required = 2,719,226 pounds of water x 100 feet of lift = 271,922,600 ft-lbs

Power or energy, especially electric power, is usually measured in kilowatt-hour (kWh) rather than ft-lbs. The conversion from ft-lbs to kWh is simple enough.

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1 kilowatt-hour (kWh) = 2,655,220 foot pounds (ft-lb).

Another example: We calculated that the energy required to lift one-acre foot of water (325,851 gallons) one foot is 2,719,226 ft-lbs. What is the energy in kilowatt-hour?

Calculated as follows:

1) Kilowatt-hour = 2,719,226 ft-lbs/2,655,220 ft-lbs per kWh = **1.02 kWh.**

Note that this energy requirement assumes 100% efficiency in the pumping plant.

Pumping plants do not operate at 100% efficiency. Energy is lost in the motor and column shaft, and friction losses occur through the strainer, suction pipe and column (see Figure 1). A properly designed and adjusted pumping plant will operate at about 70% efficiency; that is, 70% of the power goes to lifting water, the rest is used up in the mechanics of the pumping plant. The efficiency can be as low as 40% when the pumping plant is poorly designed, worn, or improperly adjusted.

Table 1 shows the amount of energy in kWh required to lift an acre-foot of water one foot in elevation over a range of overall pumping plant efficiencies. Also given is the cost to pump one acre-foot of water one foot in elevation figuring electrical power at $0.10 per kWh. Note that the energy required to lift one-acre foot of water one foot of elevation and assuming 100% efficiency is **1.02 kWh**. This is the value we calculated above.

Power Requirement to Pressurize Water

Drip and sprinkler systems are operated at 20 to 40 pounds per square inch pressure (psi). This requires energy and costs money.

1 psi pressure = 2.31 feet of water head

The energy required to create a pressure of 43 psi is the same as the energy required to lift water 100 feet.

Next to the last example: You have a drip system and are using ditch water that must be pressurized to 30 psi. A pressure of 30 psi is equal to lifting the water how many feet? How much energy is required to pressurize one acre-foot (325,851 gals) to a pressure of 30 psi and using a pump operating at 70% efficiency? A kWh costs $0.10. **The answers are: 30 psi is equal to lifting the water 69.3 feet; the energy required to pressurize one acre-foot to 30 psi is 100.8 kWh; and the cost is $10.08.**

Calculated as follows:

1. 30 psi x 2.31 feet per psi = 69.3 feet of water head; in other words, pressurizing to 30 psi is equal to lifting the water 69.2 feet.
2. One acre-foot weighs 2,719,226 pounds (325,851 gallons x 8.345 pounds).
3. Energy required in ft-lbs = weight of water x feet of lift. Therefore, 2,719,226 pounds of water x 69.3 feet of lift = 188,442,361 ft-lbs of energy per acre-foot of water.

Attachment F: Fallowed Area Mapping for Drought Impact Reporting: 2015 Assessment of Conditions in the California Central Valley

Fallowed Area Mapping for Drought Impact Reporting:

2015 Assessment of Conditions in the California Central Valley

October 14, 2015

Forrest Melton, Carolyn Rosevelt, Alberto Guzman, Lee Johnson, Isabel Zaragoza
NASA Ames Research Center Cooperative for Research in Earth Science Technology and Education & CSU Monterey Bay

James Verdin (PI), Prasad Thenkabail, Cynthia Wallace
USGS

Rick Mueller, Patrick Willis
USDA National Agricultural Statistics Service

Jeanine Jones
California Department of Water Resources

Support provided by the NASA Applied Sciences Program and the NOAA National Integrated Drought Information System Program Office

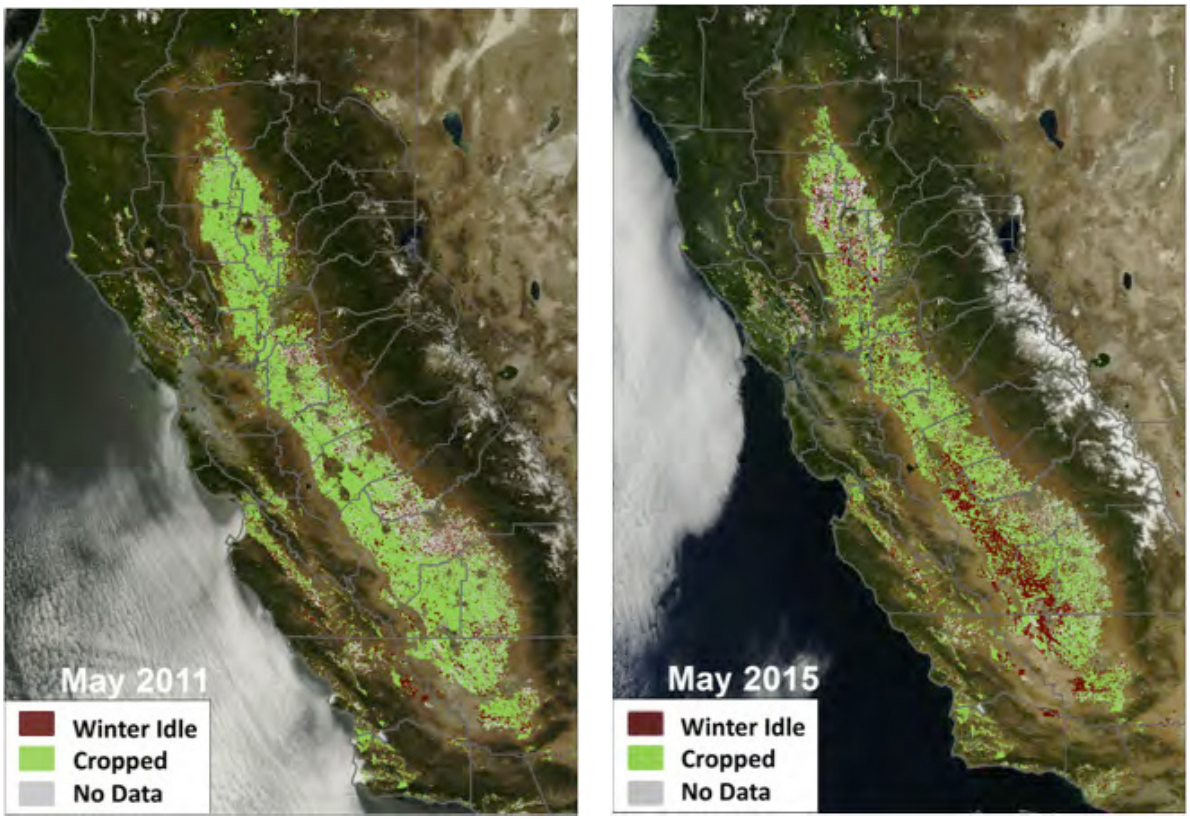
the two estimates further increases confidence in the overall accuracy of the estimates for annual fallowed acreage.

Table 1. NASA Estimates of Fallow Acreage in the California Central Valley (acres)

Year	Winter	Summer	Annual
2015	1,778,174	1,917,058	1,032,508
2011	740,445	1,394,906	405,996
Change from 2011 to 2015	1,037,729	522,152	626,512
Estimate range based on accuracy assessment	913,000 to 1,162,000	459,000 to 553,000	551,000 to 664,000

Figure 1. Maps of (A) winter, (B) summer, and (C) annual idle acreage in 2011 and 2015. Acreage that has been fallow all season is shown in brown, whereas cultivated acreage is shown in green. Areas typically associated with perennial crops or rice production are shown in gray (No Data) during the winter if no clear evidence of a crop production has been detected.

1.A Winter Conditions



Attachment G: California Department of Water Resources. SWPAO Water Deliveries, Notices to State Water Contractors

NOTICE TO STATE WATER PROJECT CONTRACTORS

Number: 10-11 ***Date:*** JUN 22 2010

Subject: ~~2010~~ State Water Project Allocation Increase to 50 Percent

From: Raphael A. Torres, DEPARTMENT OF WATER RESOURCES

The Department of Water Resources (DWR) is increasing the allocation of 2010 State Water Project (SWP) water for long-term contractors from 1,877,400 acre-feet to 2,086,000 acre-feet. DWR expects this to be the final 2010 water allocation. Based on recent runoff and current water supply conditions, SWP supplies are projected to meet 50 percent of most SWP Contractors' 2010 requested Table A amounts, which total 4,171,996 acre-feet. Attached is the revised 2010 SWP allocation table.

In addition to forecasted hydrology, DWR's new approval considered several factors including: existing storage in SWP conservation reservoirs; SWP operational constraints such as the conditions of the recent Biological Opinions for delta smelt and salmonids and the longfin smelt incidental take permit; and 2010 contractor demands. DWR may revise allocations if warranted by the year's developing hydrologic and water supply conditions.

If you have any questions or need additional information, please contact Robert Cooke, Chief of DWR's State Water Project Analysis Office, at (916) 653-4313.

2010 STATE WATER PROJECT ALLOCATION
(ACRE-FEET)

SWP CONTRACTORS	TABLE A (1)	INITIAL REQUEST (2)	APPROVED ALLOCATION (3)	PERCENT INITIAL REQUEST APPROVED (3)/(2) (4)
FEATHER RIVER				
County of Butte	27,500	27,500	13,750	50%
Plumas County FC&WCD	2,160	2,160	1,080	50%
City of Yuba City	9,600	9,600	4,800	50%
Subtotal	**39,360**	**39,360**	**19,630**	
NORTH BAY				
Napa County FC&WCD	29,025	29,025	14,513	50%
Solano County WA	47,506	47,506	23,753	50%
Subtotal	**76,531**	**76,531**	**38,266**	
SOUTH BAY				
Alameda County FC&WCD, Zone 7	80,619	80,619	40,310	50%
Alameda County WD	42,000	42,000	21,000	50%
Santa Clara Valley WD	100,000	100,000	50,000	50%
Subtotal	**222,619**	**222,619**	**111,310**	
SAN JOAQUIN VALLEY				
Oak Flat WD	5,700	5,700	2,850	50%
County of Kings	9,305	9,305	4,653	50%
Dudley Ridge WD	50,343	50,343	25,172	50%
Empire West Side ID	3,000	3,000	1,500	50%
Kern County WA	982,730	982,730	491,365	50%
Tulare Lake Basin WSD	88,922	88,922	44,461	50%
Subtotal	**1,140,000**	**1,140,000**	**570,001**	
CENTRAL COASTAL				
San Luis Obispo County FC&WCD	25,000	25,000	12,500	50%
Santa Barbara County FC&WCD	45,486	45,486	22,743	50%
Subtotal	**70,486**	**70,486**	**35,243**	
SOUTHERN CALIFORNIA				
Antelope Valley-East Kern WA	141,400	141,400	70,700	50%
Castaic Lake WA	95,200	95,200	47,600	50%
Coachella Valley WD	138,350	138,350	69,175	50%
Crestline-Lake Arrowhead WA	5,800	5,800	2,900	50%
Desert WA	55,750	55,750	27,875	50%
Littlerock Creek ID	2,300	2,300	1,150	50%
Mojave WA	82,800	82,800	41,400	50%
Metropolitan WDSC	1,911,500	1,911,500	955,750	50%
Palmdale WD	21,300	21,300	10,650	50%
San Bernardino Valley MWD	102,600	102,600	51,300	50%
San Gabriel Valley MWD	28,800	28,800	14,400	50%
San Gorgonio Pass WA	17,300	17,300	8,650	50%
Ventura County FCD	20,000	20,000	10,000	50%
Subtotal	**2,623,100**	**2,623,100**	**1,311,550**	
TOTAL	**4,171,996**	**4,171,996**	**2,086,000**	

SWPAO
6/22/2010

NOTICE TO STATE WATER PROJECT CONTRACTORS

Number: 11-06 **Date:** APR 20 2011

Subject: 2011 State Water Project Allocation Increase to 80 Percent

From: _____
Deputy Director, DEPARTMENT OF WATER RESOURCES

The Department of Water Resources (DWR) is increasing the allocation of 2011 State Water Project (SWP) water for long-term contractors from 2,920,488 acre-feet to 3,337,701 acre-feet. Based on recent precipitation, runoff, and current water supply conditions, SWP supplies are projected to meet 80 percent of SWP contractors' 2011 requested Table A amounts, which total 4,172,126 acre-feet. Attached is the revised 2011 SWP 80 percent allocation table.
This allocation increase is made consistent with the long-term water supply contracts and public policy. DWR's new approval considered several factors including existing storage in SWP conservation reservoirs, SWP operational constraints such as the conditions of the recent Biological Opinions for Delta smelt and salmonids and the longfin smelt incidental take permit, and 2011 contractor demands. DWR may revise allocations if warranted by the year's developing hydrologic and water supply conditions.

Based on this allocation increase, DWR will use the current long-term SWP contractors 70 percent schedules to arrive at the new 80 percent schedules, unless contractors submit updated schedules. DWR will send the approved monthly water delivery schedules to the long-term SWP contractors.

If you have any questions or need additional information, please contact Robert Cooke, Chief of DWR's State Water Project Analysis Office, at (916) 653-4313.

Attachment

2011 STATE WATER PROJECT ALLOCATION
(ACRE-FEET)

SWP CONTRACTORS	TABLE A (1)	INITIAL REQUEST (2)	APPROVED ALLOCATION (3)	PERCENT INITIAL REQUEST APPROVED (3)/(2) (4)
FEATHER RIVER				
County of Butte	27,500	27,500	22,000	80%
Plumas County FC&WCD	2,240	2,240	1,792	80%
City of Yuba City	9,600	9,600	7,680	80%
Subtotal	**39,340**	**39,340**	**31,472**	
NORTH BAY				
Napa County FC&WCD	29,025	29,025	23,220	80%
Solano County WA	47,556	47,556	38,045	80%
Subtotal	**76,581**	**76,581**	**61,265**	
SOUTH BAY				
Alameda County FC&WCD, Zone 7	80,619	80,619	64,495	80%
Alameda County WD	42,000	42,000	33,600	80%
Santa Clara Valley WD	100,000	100,000	80,000	80%
Subtotal	**222,619**	**222,619**	**178,095**	
SAN JOAQUIN VALLEY				
Oak Flat WD	5,700	5,700	4,560	80%
County of Kings	9,305	9,305	7,444	80%
Dudley Ridge WD	50,343	50,343	40,274	80%
Empire West Side ID	3,000	3,000	2,400	80%
Kern County WA	982,730	982,730	786,184	80%
Tulare Lake Basin WSD	88,922	88,922	71,138	80%
Subtotal	**1,140,000**	**1,140,000**	**912,000**	
CENTRAL COASTAL				
San Luis Obispo County FC&WCD	25,000	25,000	20,000	80%
Santa Barbara County FC&WCD	45,486	45,486	36,389	80%
Subtotal	**70,486**	**70,486**	**56,389**	
SOUTHERN CALIFORNIA				
Antelope Valley-East Kern WA	141,400	141,400	113,120	80%
Castaic Lake WA	95,200	95,200	76,160	80%
Coachella Valley WD	138,350	138,350	110,680	80%
Crestline-Lake Arrowhead WA	5,800	5,800	4,640	80%
Desert WA	55,750	55,750	44,600	80%
Littlerock Creek ID	2,300	2,300	1,840	80%
Mojave WA	82,800	82,800	66,240	80%
Metropolitan WDSC	1,911,500	1,911,500	1,529,200	80%
Palmdale WD	21,300	21,300	17,040	80%
San Bernardino Valley MWD	102,600	102,600	82,080	80%
San Gabriel Valley MWD	28,800	28,800	23,040	80%
San Gorgonio Pass WA	17,300	17,300	13,840	80%
Ventura County FCD	20,000	20,000	16,000	80%
Subtotal	**2,623,100**	**2,623,100**	**2,098,480**	
TOTAL	**4,172,126**	**4,172,126**	**3,337,701**	

SWPAO
4/19/2011

NOTICE TO STATE WATER PROJECT CONTRACTORS

Date: MAY 23 2012

Number: 12-09

Subject: 2012 State Water Project Allocation Increase to 65 Percent

From: _____

Carl A. Torgersen
Deputy Director
Department of Water Resources

The Department of Water Resources (DWR) is increasing the allocation of 2012 State Water Project (SWP) water for long-term contractors from 2,503,354 acre-feet to 2,711,967 acre-feet. Based on recent precipitation, runoff, and current water supply conditions, SWP supplies are projected to be 65 percent of SWP contractors' 2012 requested Table A amounts, which total 4,172,256 acre-feet. Attached is the revised 2012 SWP 65 percent allocation table.

This allocation increase is made consistent with the long-term water supply contracts and public policy. DWR's new approval considered several factors including existing storage in SWP conservation reservoirs, SWP operational constraints such as the conditions of the recent Biological Opinions for delta smelt and salmonids, and the longfin smelt incidental take permit, and 2012 contractor demands. DWR may revise allocations if warranted by the year's developing hydrologic and water supply conditions.

Based on this allocation increase, DWR will use the current long-term SWP contractors' 60 percent schedules to arrive at the new 65 percent schedules, unless contractors submit updated schedules. DWR will send the approved monthly water delivery schedules to the long-term SWP contractors.

If you have any questions or need additional information, contact Robert Cooke, Chief of DWR's State Water Project Analysis Office, at (916) 653-4313.

Attachment

2012 STATE WATER PROJECT ALLOCATION
(ACRE-FEET)

SWP CONTRACTORS	TABLE A (1)	INITIAL REQUEST (2)	APPROVED ALLOCATION (3)	PERCENT INITIAL REQUEST APPROVED (3)/(2) (4)
FEATHER RIVER				
County of Butte	27,500	27,500	17,875	65%
Plumas County FC&WCD	2,320	2,320	1,508	65%
City of Yuba City	9,600	9,600	6,240	65%
Subtotal	**39,420**	**39,420**	**25,623**	
NORTH BAY				
Napa County FC&WCD	29,025	29,025	18,866	65%
Solano County WA	47,606	47,606	30,944	65%
Subtotal	**76,631**	**76,631**	**49,810**	
SOUTH BAY				
Alameda County FC&WCD, Zone 7	80,619	80,619	52,402	65%
Alameda County WD	42,000	42,000	27,300	65%
Santa Clara Valley WD	100,000	100,000	65,000	65%
Subtotal	**222,619**	**222,619**	**144,702**	
SAN JOAQUIN VALLEY				
Oak Flat WD	5,700	5,700	3,705	65%
County of Kings	9,305	9,305	6,048	65%
Dudley Ridge WD	50,343	50,343	32,723	65%
Empire West Side ID	3,000	3,000	1,950	65%
Kern County WA	982,730	982,730	638,775	65%
Tulare Lake Basin WSD	88,922	88,922	57,799	65%
Subtotal	**1,140,000**	**1,140,000**	**741,000**	
CENTRAL COASTAL				
San Luis Obispo County FC&WCD	25,000	25,000	16,250	65%
Santa Barbara County FC&WCD	45,486	45,486	29,566	65%
Subtotal	**70,486**	**70,486**	**45,816**	
SOUTHERN CALIFORNIA				
Antelope Valley-East Kern WA	141,400	141,400	91,910	65%
Castaic Lake WA	95,200	95,200	61,880	65%
Coachella Valley WD	138,350	138,350	89,928	65%
Crestline-Lake Arrowhead WA	5,800	5,800	3,770	65%
Desert WA	55,750	55,750	36,238	65%
Littlerock Creek ID	2,300	2,300	1,495	65%
Mojave WA	82,800	82,800	53,820	65%
Metropolitan WDSC	1,911,500	1,911,500	1,242,475	65%
Palmdale WD	21,300	21,300	13,845	65%
San Bernardino Valley MWD	102,600	102,600	66,690	65%
San Gabriel Valley MWD	28,800	28,800	18,720	65%
San Gorgonio Pass WA	17,300	17,300	11,245	65%
Ventura County WPD	20,000	20,000	13,000	65%
Subtotal	**2,623,100**	**2,623,100**	**1,705,016**	
TOTAL	**4,172,256**	**4,172,256**	**2,711,967**	

SWPAO
5/21/2012

NOTICE TO STATE WATER PROJECT CONTRACTORS

Date: **March 22, 2013**

Number: **13-09**

Subject: 2013 Table A Allocation Decrease

From: Mark Anderson for

Carl A. Torgersen
Deputy Director
Department of Water Resources

The Department of Water Resources (DWR) is adjusting its projection for meeting the State Water Project (SWP) contractors' 2013 Table A requests.

DWR is reducing its projected delivery capability from 1,668,958 acre-feet to 1,460,342 acre-feet. This reduction equates to a drop in allocations from 40 percent to 35 percent for long-term SWP contractors. Enclosed is the revised 2013 SWP Allocation Table.

This decrease is primarily due to the well below average statewide snowpack and precipitation. DWR will continue to monitor the situation and may revise the allocations if warranted by the year's developing hydrologic and water supply conditions.

Based on this updated allocation, DWR will use the contractors' current 40 percent delivery schedules in developing new schedules, unless revised schedules are submitted. DWR will send an approved monthly water delivery schedule to each long-term contractor in April.

If you have any questions or need additional information, please contact Robert Cooke, Chief of DWR's State Water Project Analysis Office, at (916) 653-4313.

Enclosure

2013 STATE WATER PROJECT ALLOCATION
(ACRE-FEET)

SWP CONTRACTORS	TABLE A (1)	INITIAL REQUEST (2)	APPROVED ALLOCATION (3)	PERCENT INITIAL REQUEST APPROVED (3)/(2) (4)
FEATHER RIVER				
County of Butte	27,500	27,500	9,625	35%
Plumas County FC&WCD	2,410	2,410	844	35%
City of Yuba City	9,600	9,600	3,360	35%
Subtotal	**39,510**	**39,510**	**13,829**	
NORTH BAY				
Napa County FC&WCD	29,025	29,025	10,159	35%
Solano County WA	47,656	47,656	16,680	35%
Subtotal	**76,681**	**76,681**	**26,839**	
SOUTH BAY				
Alameda County FC&WCD, Zone 7	80,619	80,619	28,217	35%
Alameda County WD	42,000	42,000	14,700	35%
Santa Clara Valley WD	100,000	100,000	35,000	35%
Subtotal	**222,619**	**222,619**	**77,917**	
SAN JOAQUIN VALLEY				
Oak Flat WD	5,700	5,700	1,995	35%
County of Kings	9,305	9,305	3,257	35%
Dudley Ridge WD	50,343	50,343	17,620	35%
Empire West Side ID	3,000	3,000	1,050	35%
Kern County WA	982,730	982,730	343,956	35%
Tulare Lake Basin WSD	88,922	88,922	31,123	35%
Subtotal	**1,140,000**	**1,140,000**	**399,001**	
CENTRAL COASTAL				
San Luis Obispo County FC&WCD	25,000	25,000	8,750	35%
Santa Barbara County FC&WCD	45,486	45,486	15,920	35%
Subtotal	**70,486**	**70,486**	**24,670**	
SOUTHERN CALIFORNIA				
Antelope Valley-East Kern WA	141,400	141,400	49,490	35%
Castaic Lake WA	95,200	95,200	33,320	35%
Coachella Valley WD	138,350	138,350	48,423	35%
Crestline-Lake Arrowhead WA	5,800	5,800	2,030	35%
Desert WA	55,750	55,750	19,513	35%
Littlerock Creek ID	2,300	2,300	805	35%
Metropolitan WDSC	1,911,500	1,911,500	669,025	35%
Mojave WA	82,800	82,800	28,980	35%
Palmdale WD	21,300	21,300	7,455	35%
San Bernardino Valley MWD	102,600	102,600	35,910	35%
San Gabriel Valley MWD	28,800	28,800	10,080	35%
San Gorgonio Pass WA	17,300	17,300	6,055	35%
Ventura County WPD	20,000	20,000	7,000	35%
Subtotal	**2,623,100**	**2,623,100**	**918,086**	
TOTAL	**4,172,396**	**4,172,396**	**1,460,342**	

SWPAO
3/21/2013

NOTICE TO STATE WATER PROJECT CONTRACTORS

Date: APR 18 2014

Number: **14-07**

Subject: 2014 State Water Project Allocation Increase back to 5 Percent

From: _____

Carl A. Torgersen
Deputy Director
Department of Water Resources

The Department of Water Resources (DWR) is increasing the allocation of 2014 State Water Project (SWP) water for long-term contractors from 0 acre-feet to 208,628 acre-feet. Based on recent precipitation, runoff, and current water supply conditions, SWP supplies are projected to meet 5% of SWP contractors' requests for Table A water, which totals 4,172,536 acre-feet. A condition of this Allocation is that SWP contractors take delivery of this water after September 1, 2014. Attached is the modified 2014 SWP allocation table.

The 2014 Initial Allocation made on 11/19/13 was 5%, but was later reduced to Zero on 1/31/14 when hydrologic conditions turned historically dry. Although this increase from Zero back to 5% will provide much needed relief in meeting critical water needs in 2014, it remains the lowest overall allocation in SWP history. DWR is taking prudent steps in preparing for continued drought conditions should they persist into 2015.

If you have any questions or need additional information, please contact Robert Cooke, Chief of DWR's State Water Project Analysis Office, at (916) 653-4313.

Attachment

2014 STATE WATER PROJECT ALLOCATION
(ACRE-FEET)

SWP CONTRACTORS	TABLE A (1)	INITIAL REQUEST (2)	APPROVED ALLOCATION (3)	PERCENT INITIAL REQUEST APPROVED (3)/(2) (4)
FEATHER RIVER				
County of Butte	27,500	27,500	1,375	5%
Plumas County FC&WCD	2,500	2,500	125	5%
City of Yuba City	9,600	9,600	480	5%
Subtotal	**39,600**	**39,600**	**1,980**	
NORTH BAY				
Napa County FC&WCD	29,025	29,025	1,451	5%
Solano County WA	47,706	47,706	2,385	5%
Subtotal	**76,731**	**76,731**	**3,836**	
SOUTH BAY				
Alameda County FC&WCD, Zone 7	80,619	80,619	4,031	5%
Alameda County WD	42,000	42,000	2,100	5%
Santa Clara Valley WD	100,000	100,000	5,000	5%
Subtotal	**222,619**	**222,619**	**11,131**	
SAN JOAQUIN VALLEY				
Oak Flat WD	5,700	5,700	285	5%
County of Kings	9,305	9,305	465	5%
Dudley Ridge WD	48,350	48,350	2,418	5%
Empire West Side ID	3,000	3,000	150	5%
Kern County WA	982,730	982,730	49,137	5%
Tulare Lake Basin WSD	87,471	87,471	4,374	5%
Subtotal	**1,136,556**	**1,136,556**	**56,829**	
CENTRAL COASTAL				
San Luis Obispo County FC&WCD	25,000	25,000	1,250	5%
Santa Barbara County FC&WCD	45,486	45,486	2,274	5%
Subtotal	**70,486**	**70,486**	**3,524**	
SOUTHERN CALIFORNIA				
Antelope Valley-East Kern WA	144,844	144,844	7,242	5%
Castaic Lake WA	95,200	95,200	4,760	5%
Coachella Valley WD	138,350	138,350	6,918	5%
Crestline-Lake Arrowhead WA	5,800	5,800	290	5%
Desert WA	55,750	55,750	2,788	5%
Littlerock Creek ID	2,300	2,300	115	5%
Metropolitan WDSC	1,911,500	1,911,500	95,575	5%
Mojave WA	82,800	82,800	4,140	5%
Palmdale WD	21,300	21,300	1,065	5%
San Bernardino Valley MWD	102,600	102,600	5,130	5%
San Gabriel Valley MWD	28,800	28,800	1,440	5%
San Gorgonio Pass WA	17,300	17,300	865	5%
Ventura County WPD	20,000	20,000	1,000	5%
Subtotal	**2,626,544**	**2,626,544**	**131,328**	
TOTAL	**4,172,536**	**4,172,536**	**208,628**	

SWPAO
4/16/2014

NOTICE TO STATE WATER PROJECT CONTRACTORS

Date: MAR 02 2015

Number: **15 - 03**

Subject: 2015 State Water Project Allocation Increase – 20 Percent

From: _____
Carl A. Torgersen

Department of Water Resources

The Department of Water Resources (DWR) is increasing the allocation of 2015 State Water Project (SWP) water for the long-term contractors from 635,759 acre-feet to 839,566 acre-feet. Due primarily to runoff from storms in December and February which was exported and stored in the San Luis Reservoir, SWP supplies are projected to increase from 15 percent to 20 percent of most SWP contractors' requests for Table A water, which totals 4,172,686 acre-feet. Attached is the updated 2015 SWP allocation table.

This allocation is made consistent with the long-term water supply contracts and public policy. DWR considered several factors, including existing conditions, SWP operational constraints such as the conditions of the recent Biological Opinions for Delta Smelt, Salmonids and Longfin Smelt incidental take permit, and 2015 contractor demands. DWR may revise allocations if warranted by the year's developing hydrologic and water supply conditions.

Based on this updated allocation, DWR will use the 30 percent delivery schedules submitted by the contractors earlier this year to arrive at the 20 percent schedules, unless revised schedules are submitted by the contractors. DWR will send an approved monthly water delivery schedule for 2015 to each long-term contractor in March 2015.

If you have any questions or need additional information, please contact Robert Cooke, Chief of DWR's State Water Project Analysis Office, at (916) 653-4313.

Attachment

2015 STATE WATER PROJECT ALLOCATION
(ACRE-FEET)

SWP CONTRACTORS	TABLE A (1)	INITIAL REQUEST (2)	APPROVED ALLOCATION (3)	PERCENT INITIAL REQUEST APPROVED (3)/(2) (4)
FEATHER RIVER				
County of Butte	27,500	27,500	6,000	22%
Plumas County FC&WCD	2,600	2,600	730	28%
City of Yuba City	9,600	9,600	2,400	25%
Subtotal	**39,700**	**39,700**	**9,130**	
NORTH BAY				
Napa County FC&WCD	29,025	29,025	7,256	25%
Solano County WA	47,756	47,756	11,939	25%
Subtotal	**76,781**	**76,781**	**19,195**	
SOUTH BAY				
Alameda County FC&WCD, Zone 7	80,619	80,619	16,124	20%
Alameda County WD	42,000	42,000	8,400	20%
Santa Clara Valley WD	100,000	100,000	20,000	20%
Subtotal	**222,619**	**222,619**	**44,524**	
SAN JOAQUIN VALLEY				
Oak Flat WD	5,700	5,700	1,140	20%
County of Kings	9,305	9,305	1,861	20%
Dudley Ridge WD	45,350	45,350	9,070	20%
Empire West Side ID	3,000	3,000	600	20%
Kern County WA	982,730	982,730	196,546	20%
Tulare Lake Basin WSD	87,471	87,471	17,494	20%
Subtotal	**1,133,556**	**1,133,556**	**226,711**	
CENTRAL COASTAL				
San Luis Obispo County FC&WCD	25,000	25,000	5,000	20%
Santa Barbara County FC&WCD	45,486	45,486	9,097	20%
Subtotal	**70,486**	**70,486**	**14,097**	
SOUTHERN CALIFORNIA				
Antelope Valley-East Kern WA	144,844	144,844	28,969	20%
Castaic Lake WA	95,200	95,200	19,040	20%
Coachella Valley WD	138,350	138,350	27,670	20%
Crestline-Lake Arrowhead WA	5,800	5,800	1,160	20%
Desert WA	55,750	55,750	11,150	20%
Littlerock Creek ID	2,300	2,300	460	20%
Metropolitan WDSC	1,911,500	1,911,500	382,300	20%
Mojave WA	85,800	85,800	17,160	20%
Palmdale WD	21,300	21,300	4,260	20%
San Bernardino Valley MWD	102,600	102,600	20,520	20%
San Gabriel Valley MWD	28,800	28,800	5,760	20%
San Gorgonio Pass WA	17,300	17,300	3,460	20%
Ventura County WPD	20,000	20,000	4,000	20%
Subtotal	**2,629,544**	**2,629,544**	**525,909**	
TOTAL	**4,172,686**	**4,172,686**	**839,566**	

SWPAO
3/2/2015

NOTICE TO STATE WATER PROJECT CONTRACTORS

Date: APR 2 1 2016

Number: **16 - 06**

Subject: 2016 State Water Project Allocation – 60 Percent

From: Mark E. Andersen

Mark E. Andersen
Acting Deputy Director
Department of Water Resources

The Department of Water Resources (DWR) is increasing the allocation of 2016 State Water Project (SWP) water for the long-term contractors from 1,898,964 acre-feet to 2,527,629 acre-feet. Due primarily to March storms, SWP supplies are projected to increase from 45 percent to 60 percent of most SWP contractors' requests for Table A water, which totals 4,172,786 acre-feet. Attached is the updated 2016 SWP Allocation Table.

In addition, DWR received requests for delivery of SWP contractors' allocated carryover water from previous years totaling 184,274 acre-feet based on the 2015 Water Delivery Finalization Report. DWR approves all requested carryover water for delivery in 2016.

This allocation increase is made consistent with the current and projected hydrological conditions and also with the long-term water supply contracts and public policy. DWR considered several factors, including California's persistent drought evidenced by below normal snow accumulation and continued low storage in SWP facilities located south of the Delta; SWP operational constraints under its water right permits; the Biological Opinions for Delta Smelt and Salmon; the Longfin Smelt incidental take permit; and the 2016 contractors demands.

If you have any questions or need additional information, please contact Craig J. Trombly, Acting Chief, State Water Project Analysis Office, at (916) 653-4547.

Attachment

2016 STATE WATER PROJECT ALLOCATION
(ACRE-FEET)

SWP CONTRACTORS	TABLE A (1)	INITIAL REQUEST (2)	APPROVED ALLOCATION (3)	PERCENT INITIAL REQUEST APPROVED (3)/(2) (4)
FEATHER RIVER				
County of Butte	27,500	27,500	27,500	100%
Plumas County FC&WCD	2,700	2,700	1,620	60%
City of Yuba City	9,600	9,600	7,200	75%
Subtotal	**39,800**	**39,800**	**36,320**	
NORTH BAY				
Napa County FC&WCD	29,025	29,025	21,769	75%
Solano County WA	47,756	47,756	35,817	75%
Subtotal	**76,781**	**76,781**	**57,586**	
SOUTH BAY				
Alameda County FC&WCD, Zone 7	80,619	80,619	48,371	60%
Alameda County WD	42,000	42,000	25,200	60%
Santa Clara Valley WD	100,000	100,000	60,000	60%
Subtotal	**222,619**	**222,619**	**133,571**	
SAN JOAQUIN VALLEY				
Oak Flat WD	5,700	5,700	3,420	60%
County of Kings	9,305	9,305	5,583	60%
Dudley Ridge WD	45,350	45,350	27,210	60%
Empire West Side ID	3,000	3,000	1,800	60%
Kern County WA	982,730	982,730	589,638	60%
Tulare Lake Basin WSD	87,471	87,471	52,483	60%
Subtotal	**1,133,556**	**1,133,556**	**680,134**	
CENTRAL COASTAL				
San Luis Obispo County FC&WCD	25,000	25,000	15,000	60%
Santa Barbara County FC&WCD	45,486	45,486	27,292	60%
Subtotal	**70,486**	**70,486**	**42,292**	
SOUTHERN CALIFORNIA				
Antelope Valley-East Kern WA	144,844	144,844	86,906	60%
Castaic Lake WA	95,200	95,200	57,120	60%
Coachella Valley WD	138,350	138,350	83,010	60%
Crestline-Lake Arrowhead WA	5,800	5,800	3,480	60%
Desert WA	55,750	55,750	33,450	60%
Littlerock Creek ID	2,300	2,300	1,380	60%
Metropolitan WDSC	1,911,500	1,911,500	1,146,900	60%
Mojave WA	85,800	85,800	51,480	60%
Palmdale WD	21,300	21,300	12,780	60%
San Bernardino Valley MWD	102,600	102,600	61,560	60%
San Gabriel Valley MWD	28,800	28,800	17,280	60%
San Gorgonio Pass WA	17,300	17,300	10,380	60%
Ventura County WPD	20,000	20,000	12,000	60%
Subtotal	**2,629,544**	**2,629,544**	**1,577,726**	
TOTAL	**4,172,786**	**4,172,786**	**2,527,629**	

SWPAO
4/21/2016

Attachment H: U.S. Bureau of Reclamation. “Summary of Water Supply Allocations”

SUMMARY OF WATER SUPPLY ALLOCATIONS

Year		Precent Supply						
2016	Contractors	Apr 1, 2016	11-Apr-2016	21-Apr-2016	6-May-2016	18-Jul-2016		
	North of Delta							
	Agricultural Contractors (Ag)	100%						
	Urban Contractors (M&I)	100%						
	Wildlife Refuges (Level 2)	100%						
	Settlement Contractors/Water Rights	100%						
	American River M&I Contractors	100%						
	In Delta - Contra Costa	100%						
	South of Delta							
	Agricultural Contractors (Ag)	5%						
	Urban Contractors (M&I)	55%*						
	Wildlife Refuges (Level 2)	100%						
	Settlement Contractors/Water Rights	100%						
	Eastside Division Contractors	0%**						
	Friant - Class 1	30%	40%	50%	65%	75%		
	Friant - Class 2	***		****				

* Of historical use.

** Due to lack of available CVP supplies from New Melones Reservoir.

***An Uncontrolled Season supply of 100,000 acre-feet and unreleased Restoration Flow supply related to the San Joaquin River Restoration Program c
85,000 acre-feet are being made available as blocks that need to be scheduled and delivered by May 1 and May 15 respectively to avert flood management concerns. ****to be scheduled and delivered by the end of April 2016.

Year		Precent Supply						
2015	Contractors	Feb 27, 2015						
	North of Delta							
	Agricultural Contractors (Ag)	0%						
	Urban Contractors (M&I)	25%*						
	Wildlife Refuges (Level 2)	75%**						
	Settlement Contractors/Water Rights	75%**						
	American River M&I Contractors	25%*						
	In Delta - Contra Costa	25%*						
	South of Delta							
	Agricultural Contractors (Ag)	0%						
	Urban Contractors (M&I)	25%*						
	Wildlife Refuges (Level 2)	75%**						
	Settlement Contractors/Water Rights	75%**						
	Eastside Division Contractors	0%						
	Friant - Class 1	0%						
	Friant - Class 2	0%						

* Health and Safety needs or at least 25% of their historical use, whichever is greater.

** May be reduced if current dry conditions persist.

SUMMARY OF WATER SUPPLY ALLOCATIONS

Year		Precent Supply						
2014	Contractors	Feb 21, 2014	Apr 18, 2014	May 13, 2014				
	North of Delta							
	Agricultural Contractors (Ag)	0%	0%	0%				
	Urban Contractors (M&I)	50%	50%	50%				
	Wildlife Refuges (Level 2)	40%	75%	75%				
	Settlement Contractors/Water Rights	40%	75%	75%				
	American River M&I Contractors	50%	50%	50%				
	In Delta - Contra Costa	50%	50%	50%				
	South of Delta							
	Agricultural Contractors (Ag)	0%	0%	0%				
	Urban Contractors (M&I)	50%	50%	50%				
	Wildlife Refuges (Level 2)	40%	40%	65%				
	Settlement Contractors/Water Rights	40%	40%	65%				
	Eastside Division Contractors	55% (85,250 AF)	55% (85,250 AF)	55% (85,250 AF)				
	Friant - Class 1	0%	0%	0%				
	Friant - Class 2	0%	0%	0%				

Year		Precent Supply							
2013	Contractors	Feb 25, 2013	Mar 22, 2013	Apr 5,2013	Apr 17,2013	May 14, 2013	Jun 5, 2013	Jun 13, 2013	Jul 15, 2013
	North of Delta								
	Agricultural Contractors (Ag)	75%	75%	75%	75%	75%	75%	75%	75%
	Urban Contractors (M&I)	100%	100%	100%	100%	100%	100%	100%	100%
	Wildlife Refuges (Level 2)	100%	100%	100%	100%	100%	100%	100%	100%
	Settlement Contractors/Water Rights	100%	100%	100%	100%	100%	100%	100%	100%
	American River M&I Contractors	75%	75%	75%	75%	75%	75%	75%	75%
	In Delta - Contra Costa	75%	75%	75%	75%	75%	75%	75%	75%
	South of Delta								
	Agricultural Contractors (Ag)	25%	20%	20%	20%	20%	20%	20%	20%
	Urban Contractors (M&I)	75%	70%	70%	70%	70%	70%	70%	70%
	Wildlife Refuges (Level 2)	100%	100%	100%	100%	100%	100%	100%	100%
	Settlement Contractors/Water Rights	100%	100%	100%	100%	100%	100%	100%	100%
	Eastside Division Contractors	100% (155,000 AF)	100% (155,000 AF)	100% (155,000 AF)	100% (155,000 AF)	100% (155,000 AF)	100% (155,000 AF)	100% (155,000 AF)	100% (155,000 AF)
	Friant - Class 1	65%	65%	55%	50%	45%	50%	55%	62%
	Friant - Class 2	0%	0%	0%	0%	0%	0%	0%	0%

Year		Precent Supply				
2012	Contractors	Feb 22, 2012	Apr 13, 2012	Apr 27, 2012		
	North of Delta					
	Agricultural Contractors (Ag)	30%	100%	100%		
	Urban Contractors (M&I)	75%	100%	100%		
	Wildlife Refuges (Level 2)	75%	100%	100%		
	Settlement Contractors/Water Rights	75%	100%	100%		
	South of Delta					
	Agricultural Contractors (Ag)	30%	40%	40%		
	Urban Contractors (M&I)	75%	75%	75%		
	Wildlife Refuges (Level 2)	75%	100%	100%		
	Settlement Contractors/Water Rights	75%	100%	100%		
	Eastside Division Contractors	100% (155,000 AF)	100% (155,000 AF)	100% (155,000 AF)		
	Friant - Class 1	35%	45%	50%		
	Friant - Class 2	0%	0%	0%		

SUMMARY OF WATER SUPPLY ALLOCATIONS

Year		Precent Supply				
2011	Contractors	Feb 18, 2011	Mar 22, 2011	Mar 28, 2011	Apr 8, 2011	Apr 25, 2011
	North of Delta					
	Agricultural Contractors (Ag)	100%	100%	100%	100%	100%
	Urban Contractors (M&I)	100%	100%	100%	100%	100%
	Wildlife Refuges (Level 2)	100%	100%	100%	100%	100%
	Settlement Contractors/Water Rights	100%	100%	100%	100%	100%
	South of Delta					
	Agricultural Contractors (Ag)	50%	55%	65%	75%	80%
	Urban Contractors (M&I)	75%	80%	90%	100%	100%
	Wildlife Refuges (Level 2)	100%	100%	100%	100%	100%
	Settlement Contractors/Water Rights	100%	100%	100%	100%	100%
	Eastside Division Contractors	100% (155,000 AF)	100% (155,000 AF)	100% (155,000 AF)	100% (155,000 AF)	100% (155,000 AF)
	Friant - Class 1	100% (800,000 AF)	100% (800,000 AF)	100% (800,000 AF)	100% (800,000 AF)	100% (800,000 AF)
	Friant - Class 2	20% (280,000 AF)	20% (280,000 AF)	20% (280,000 AF)	20% (280,000 AF)	20% (280,000 AF)

Year		Precent Supply			
2010	Contractors	Feb 26, 2010	Mar 16, 2010	Apr 15, 2010	Jun 14, 2010
	North of Delta				
	Agricultural Contractors (Ag)	5%	50%	100%	100%
	Urban Contractors (M&I)	55%	75%	100%	100%
	Wildlife Refuges (Level 2)	100%	100%	100%	100%
	Settlement Contractors/Water Rights	100%	100%	100%	100%
	South of Delta				
	Agricultural Contractors (Ag)	5%	25%	30%	45%
	Urban Contractors (M&I)	55%	75%	75%	75%
	Wildlife Refuges (Level 2)	100%	100%	100%	100%
	Settlement Contractors/Water Rights	100%	100%	100%	100%
	Eastside Division Contractors	100% (155,000 AF)		100% (155,000 AF)	
	Friant - Class 1	100%	100%	100%	
	Friant - Class 2	0%	10%	15%	

SUMMARY OF WATER SUPPLY ALLOCATIONS

Year	Contractors	Precent Supply	
2009		North of Delta	South of Delta
	Agricultural Contractors	40[1]	10[5]
	Urban Contractors	75 & 100[2]	60[6]
	Wildlife Refuges	100[4]	100[4]
	Sacramento River water rights and San Joaquin River Exchange Contractors	100[4]	100[4]
	East Side Contractors	18,000 AF[7]	
	Friant - Class 1	77[3]	
	Friant - Class 2	18[8]	

[1]Increase of 5% from 0% to 5% for North of Delta Ag on 3/20/2009.
Increase of 10% from 5% to 15% for North of Delta Ag on 4/21/2009.
Increase of 25% from 15% to 40% for North of Delta Ag on 5/22/2009.

[2]Increase of 5% from 50% to 55% for North of Delta MI on 3/20/2009.
Increase of 10% from 55% to 65% for North of Delta MI on 4/21/2009.
Increase of 10% from 65% to 75% for North of Delta Sacramento River MI Contractors on 5/22/2009.
Increase of 35% from 65% to 100% for North of Delta American River Division MI Contractors on 5/22/2009.

[3]Increase of 40% from 25% to 65% for Friant Class 1 on 3/20/2009.
Increase of 20% from 65% to 85% for Friant Class 1 on 3/27/2009.
Increase of 5% from 85% to 90% for Friant Class 1 on 4/17/2009.
Increase of 10% from 90% to 100% for Friant Class 1 on 4/23/2009.
Decrease of 23% from 100% to 77% for Friant Class 1 on 6/12/2009.

[4]Increase of 25% from 75% to 100% for North & South of Delta Wildlife Refuges, Sacramento River water rights & San Joaquin River Exchange Contractors on 3/30/2009.

[5]Increase of 10% from 0% to 10% for South of Delta Ag on 4/21/2009.

[6]Increase of 10% from 50% to 60% for South of Delta MI on 4/21/2009.

[7]Increase of 18,000 AF from Zero to 18,000 AF for East Side Contractors on 4/21/2009.

[8]Increase of 18% from 0% to 18% for Friant Class 2 on 5/22/2009.

SUMMARY OF WATER SUPPLY ALLOCATIONS

Year	Contractors	Percent Supply	
2008		North of Delta	South of Delta
	Agricultural Contractors	40***	40***
	Urban Contractors	75	75
	Wildlife Refuges	100	100
	Sacramento River water rights and San Joaquin River Exchange Contractors	100	
	East Side Contractors	23% (35,000 AF)*	
	Friant - Class 1	100	
	Friant - Class 2	5**	

*Increase of 8% (11,000 AF) from 15% (24,000 AF) to 23% (35,000 AF) on 3-20-2008.

**Increase of 5% from 0% to 5% for Friant - Class 2 on 3-20-2008.

*** Decrease of 5% from 45% to 40% for AG on 6-3-2008.

Year	Contractors	Percent Supply	
2007		North of Delta	South of Delta
	Agricultural Contractors	100 *	50 **
	Urban Contractors	100 *	75
	Wildlife Refuges	100 *	100 **
	Sacramento River water rights and San Joaquin River Exchange Contractors	100***	
	East Side Contractors	29% (45,000 AF) ****	
	Friant - Class 1	65 *****	
	Friant - Class 2	0	

*Increase of 65% from 35% to 100% for Ag on 3-16-2007.
Increase of 25% from 75% to 100% for MI & Wildlife Refuges on 3-16-2007.
**Increase of 15% from 35% to 50% for Ag on 3-16-2007.
Increase of 25% from 75% to 100% for Wildlife Refuges on 3-16-2007.
***Increase of 25% from 75% to 100% for Sac River Wtr Rights and Exchange contractors on 3-16-2007.
****Increase of 13% (20,000 AF) from 16% (25,000 AF) to 29% (45,000 AF) on 3-16-2007.
*****Increase of 10% from 50% to 60% for Friant - Class 1 on 5-4-2007.
Increase of 5% from 60% to 65% for Friant-Class 1 on 8-1-2007.

Year	Contractors	Percent Supply	
2006		North of Delta	South of Delta
	Agricultural Contractors	100	100**
	Urban Contractors	100	100**
	Wildlife Refuges	100	100**
	Sacramento River water rights and San Joaquin River Exchange Contractors	100	
	East Side Contractors	100% (155,000 AF)	
	Friant - Class 1	100	
	Friant - Class 2	Uncontrolled Season*	

* Uncontrolled Season from March 1 through Mid June 2006.

** Increase of 20% from 65% to 85% for AG on 4-20-06.
Increase of 10% from 90% to 100% for MI on 4-20-06.
Increase of 15% from 85% to 100% for AG on 5-11-06.

Year	Contractors	Percent Supply	
2005		North of Delta	South of Delta
	Agricultural Contractors	**100***	**85****
	Urban Contractors	**100***	**100****
	Wildlife Refuges	100	100
	Sacramento River water rights and San Joaquin River Exchange Contractors	100	
	East Side Contractors	**43,000 AF *****	
	Friant - Class 1	100	
	Friant - Class 2	Uncontrolled Season	

* Increase of 35% from 65% to 100% for AG and increase of 10% from 90% to 100% for MI on 4-15-05.

** Increase of 5% from 65% to 70% for AG & 90% to 95% for MI on 4-15-05.
Increase of 5% from 70% to 75% for AG & 95% to 100% for MI on 4-28-05.
Increase of 10% from 75% to 85% for AG on 5-18-05.
Increase of 5% from 85% to 90% for AG on 7-25-05.
Decrease of 5% from 90% to 85% for AG on 1-12-06

*** Increase from 2,000 AF to 38,000 AF on 4-15-05.
Increase from 38,000 AF to 43,000 AF on 5-18-05.

Year	Contractors	Percent Supply	
2004		North of Delta	South of Delta
	Agricultural Contractors	100	**70 ***
	Urban Contractors	100	**95 ***
	Wildlife Refuges	100	100
	Sacramento River water rights and San Joaquin River exchange contractors	100	
	East Side Contractors	0	
	Friant - Class 1	100	
	Friant - Class 2	8	

March 2004 allocation - Based on 90% exceedence forecast
*** Increase in allocation of 5% to Ag & M&I on Sep 13th**

Year	Contractors	Percent Supply	
2003		North of Delta	South of Delta
	Agricultural Contractors	100	**75 ***
	Urban Contractors	100	**100 ***
	Wildlife Refuges	100	100
	Sacramento River water rights and San Joaquin River exchange contractors	100	
	East Side Contractors	6	
	Friant - Class 1	100	
	Friant - Class 2	5	

*** 5% increase in allocation Jul 1 for both Ag & M&I**

SUMMARY OF WATER SUPPLY ALLOCATIONS

Year	Contractors	Percent Supply	
2002		North of Delta	South of Delta
	Agricultural Contractors	100	**70 ***
	Urban Contractors	100	**95 ***
	Wildlife Refuges	100	100
	Sacramento River water rights and San Joaquin River exchange contractors	100	
	East Side Contractors	8	
	Friant - Class 1	100	
	Friant - Class 2	8	
	*** 5% increase in allocation on Sep 10, 2002**		

Year	Contractors	Percent Supply	
2001		North of Delta	South of Delta
	Agricultural Contractors	60	**49 ***
	Urban Contractors	85	**77 ***
	Wildlife Refuges	100	100
	Sacramento River water rights and San Joaquin River exchange contractors	100	
	East Side Contractors	22	
	Friant - Class 1	100	
	Friant - Class 2	5	
	*** 2% increase in allocation on Oct 19, 2001**		

Year	Contractors	Percent Supply	
2000		North of Delta	South of Delta
	Agricultural Contractors	100	65
	Urban Contractors	100	90
	Wildlife Refuges	100	
	Sacramento River water rights and San Joaquin River exchange contractors	100	
	Stanislaus	58 percent of supply	
	Friant - Class 1	100	
	Friant - Class 2	17	

Year	Contractors	Percent Supply	
1999		North of Delta	South of Delta
	Agricultural Contractors	100	70
	Urban Contractors	95	95
	Wildlife Refuges	100	
	Sacramento River water rights and San Joaquin River exchange contractors	100	
	Stanislaus	39	
	Friant - Class 1	100	
	Friant - Class 2	20	

Year	Contractors	Percent Supply	
1998		North of Delta	South of Delta
	Agricultural Contractors	100	100
	Urban Contractors	100	100
	Wildlife Refuges	100	
	Sacramento River water rights and San Joaquin River exchange contractors	100	
	Stanislaus	32	
	Friant - Class 1	100	
	Friant - Class 2	10	

Year	Contractors	Percent Supply
1997		
	Agricultural Contractors	90
	Urban Contractors	90 - 100
	Wildlife Refuges	As scheduled
	Sacramento River water rights and San Joaquin River exchange contractors	100
	Stanislaus River	100 of request
	Friant - Class 1	100
	Friant - Class 2	60

SUMMARY OF WATER SUPPLY ALLOCATIONS

Year	Contractors	Percent Supply	
1996		North of Delta	South of Delta
	Agricultural Contractors	100	95
	Urban Contractors	100	100
	Wildlife Refuges	100	*
	Sacramento River water rights and San Joaquin River exchange contractors	100	
	Friant - Class 1	100	
	Friant - Class 2	58	

*** Meet 100 percent of scheduled need**

Year	Contractors	Percent Supply	
1995		North of Delta	South of Delta
	Agricultural Contractors	100	100
	Urban Contractors	95	100
	Wildlife Refuges	100	100
	Sacramento River water rights and San Joaquin River exchange contractors	100	
	Friant - Class 1	100	
	Friant - Class 2	100	

Year	Contractors	Percent Supply
1994		
	Agricultural Contractors	35
	Urban Contractors	75 of historical use
	Wildlife Refuges	75
	Sacramento River water rights and San Joaquin River exchange contractors	75
	Friant - Class 1	80
	Friant - Class 2	0

Year	Contractors	Percent Supply	
1993		North of Delta	South of Delta
	Agricultural Contractors	100	50
	Urban Contractors	100	75 of historical use
	Wildlife Refuges	100	75
	Sacramento River water rights and San Joaquin River exchange contractors	100	
	Friant - Class 1	100	
	Friant - Class 2	90	

Year	Contractors	Percent Supply
1992		
	Agricultural Contractors	25
	Urban Contractors	75 of historical use
	Wildlife Refuges	75 of historical supply
	Sacramento River water rights and San Joaquin River exchange contractors	75
	Friant - Class 1	83
	Friant - Class 2	0

Year	Contractors	Percent Supply
1991		
	Agricultural Contractors	25
	Urban Contractors	25-50
	Sacramento River water rights and San Joaquin River exchange contractors	75
	Plus Hardship Water	
	Friant - Class 1	100
	Friant - Class 2	0

No deficiencies on water deliveries 1978-1989

Year	Contractors	Percent Supply
1990		
	Agricultural Contractors	50
	Urban Contractors	50-75
	Sacramento River water rights and San Joaquin River exchange contractors	100
	Friant - Class 1	68
	Friant - Class 2	0

Year	Contractors	Percent Supply
1977		
	Agricultural Contractors	25
	Urban Contractors	25-50
	Sacramento River water rights and San Joaquin River exchange contractors	75
	Friant - Class 1	25
	Friant - Class 2	0

Attachment I: California Department of Water Resources
Sacramento River Runoff Index

WSIHIST (01/19/16 1412)

Department of Water Resources
California Cooperative Snow Surveys

Chronological Reconstructed Sacramento and San Joaquin Valley
Water Year Hydrologic Classification Indices

Based on measured unimpaired runoff (in million acre-feet), subject to revision.
*** See explanatory notes at bottom ***

	[.....Sacramento Valley.....]					[.....San Joaquin Valley.....]				
	[.....Runoff (maf).....]			[..WY Index..]		[.....Runoff (maf).....]			[..WY Index..]	
WY	Oct-Mar	Apr-Jul	WYsum	Index	Yr-type	Oct-Mar	Apr-Jul	WYsum	Index	Yr-type
1901						3.49	5.58	9.39	4.60	W
1902						1.12	3.81	5.08	3.41	AN
1903						1.45	4.13	5.71	3.45	AN
1904						1.96	5.37	7.64	4.31	W
1905						1.82	3.36	5.30	3.24	AN
1906	12.57	12.92	26.71	11.76	W	2.53	9.24	12.43	6.70	W
1907	18.96	13.45	33.70	14.07	W	3.67	7.61	11.82	6.20	W
1908	8.29	5.60	14.77	7.73	BN	0.98	2.17	3.32	2.40	D
1909	20.61	8.98	30.68	12.10	W	2.85	5.91	8.97	4.59	W
1910	13.12	6.11	20.12	9.38	W	2.87	3.62	6.64	3.65	AN
1911	12.27	13.12	26.38	11.74	W	3.63	7.52	11.48	5.97	W
1912	4.84	5.65	11.41	6.71	BN	0.54	2.57	3.21	2.55	BN
1913	5.72	6.29	12.85	6.24	D	0.44	2.34	3.00	2.00	C
1914	16.72	10.08	27.81	10.92	W	2.72	5.67	8.69	4.35	W
1915	11.41	11.42	23.86	10.99	W	1.29	4.95	6.40	4.10	W
1916	14.25	8.89	24.14	10.83	W	2.67	5.50	8.38	4.65	W
1917	7.25	9.14	17.26	8.83	AN	1.66	4.84	6.66	4.13	W
1918	5.27	4.89	10.99	6.19	D	1.07	3.40	4.59	3.08	BN
1919	8.12	6.77	15.66	7.00	BN	1.06	2.99	4.09	2.62	BN
1920	3.63	4.91	9.20	5.15	C	0.72	3.29	4.09	2.64	BN
1921	15.47	7.52	23.80	9.20	AN	1.97	3.84	5.90	3.23	AN
1922	6.63	10.57	17.98	8.97	AN	1.51	5.99	7.68	4.54	W
1923	6.21	6.27	13.21	7.06	BN	1.39	3.95	5.51	3.55	AN
1924	3.27	1.94	5.74	3.87	C	0.45	1.03	1.50	1.42	C
1925	8.76	6.51	15.99	6.39	D	1.45	3.93	5.51	2.93	BN
1926	6.37	4.79	11.76	5.75	D	0.89	2.56	3.49	2.30	D
1927	14.34	8.75	23.83	9.52	W	1.80	4.56	6.50	3.56	AN
1928	10.24	5.86	16.76	8.27	AN	1.69	2.64	4.37	2.63	BN
1929	4.00	3.84	8.40	5.22	C	0.52	2.29	2.84	2.00	C
1930	8.24	4.65	13.52	5.90	D	0.76	2.44	3.25	2.02	C
1931	3.52	2.09	6.10	3.66	C	0.46	1.18	1.66	1.20	C
1932	6.28	6.24	13.12	5.48	D	1.79	4.69	6.63	3.41	AN
1933	3.73	4.66	8.94	4.63	C	0.49	2.77	3.34	2.44	D
1934	5.68	2.45	8.63	4.07	C	0.98	1.26	2.28	1.44	C
1935	6.27	9.69	16.59	6.98	BN	1.26	5.03	6.41	3.56	AN
1936	10.32	6.41	17.35	7.75	BN	2.00	4.38	6.49	3.74	AN
1937	5.50	7.24	13.33	6.87	BN	1.78	4.66	6.53	3.90	W
1938	17.96	12.93	31.83	12.62	W	3.58	7.33	11.24	5.89	W
1939	4.56	3.04	8.18	5.58	D	1.00	1.83	2.90	2.20	D
1940	14.78	6.93	22.43	8.88	AN	2.49	4.04	6.59	3.36	AN
1941	16.32	9.77	27.08	11.47	W	2.22	5.51	7.93	4.43	W
1942	14.33	9.93	25.24	11.27	W	1.93	5.28	7.38	4.44	W
1943	13.37	6.90	21.13	9.77	W	2.86	4.28	7.28	4.03	W
1944	4.81	4.93	10.43	6.35	D	0.87	2.97	3.92	2.76	BN
1945	8.42	5.92	15.06	6.80	BN	2.07	4.37	6.60	3.59	AN
1946	10.89	5.97	17.62	7.70	BN	1.99	3.65	5.73	3.30	AN
1947	5.90	3.83	10.39	5.61	D	1.26	2.12	3.42	2.18	D
1948	5.39	9.55	15.75	7.12	BN	0.56	3.58	4.21	2.70	BN
1949	5.73	5.59	11.97	6.09	D	0.62	3.12	3.79	2.53	BN
1950	7.01	6.72	14.44	6.62	BN	1.02	3.57	4.65	2.85	BN
1951	16.77	5.42	22.95	9.18	AN	4.35	2.83	7.25	3.14	AN
1952	13.86	13.68	28.60	12.38	W	2.18	6.84	9.30	5.17	W
1953	10.84	8.26	20.09	9.55	W	1.07	3.18	4.35	3.03	BN
1954	9.74	6.81	17.43	8.51	AN	1.10	3.16	4.30	2.72	BN
1955	5.19	5.07	10.98	6.14	D	0.78	2.67	3.50	2.30	D
1956	20.32	8.60	29.89	11.38	W	4.14	5.29	9.67	4.46	W
1957	7.72	6.29	14.89	7.83	AN	1.02	3.19	4.29	3.01	BN
1958	16.37	12.24	29.71	12.16	W	1.67	6.40	8.36	4.77	W
1959	7.40	3.84	12.05	6.75	BN	0.98	1.85	2.98	2.21	D
1960	7.72	4.65	13.06	6.20	D	0.85	2.07	2.96	1.85	C
1961	6.87	4.39	11.97	5.68	D	0.54	1.50	2.10	1.38	C
1962	8.17	6.23	15.11	6.65	BN	1.26	4.24	5.61	3.07	BN
1963	12.01	10.09	22.99	9.63	W	1.68	4.37	6.24	3.57	AN
1964	5.90	4.37	10.92	6.41	D	0.93	2.14	3.14	2.19	D
1965	16.59	8.13	25.64	10.15	W	3.20	4.55	8.13	3.81	W

1966	7.42	4.84	12.95	7.16	BN	1.49	2.42	3.98	2.51	BN
1967	12.14	11.01	24.06	10.20	W	2.46	7.09	9.98	5.25	W
1968	8.66	4.12	13.64	7.24	BN	1.02	1.85	2.94	2.21	D
1969	15.33	10.68	26.98	11.05	W	3.84	8.14	12.29	6.09	W
1970	18.87	4.35	24.06	10.40	W	2.55	2.96	5.61	3.18	AN
1971	12.71	8.90	22.57	10.37	W	1.56	3.23	4.91	2.89	BN
1972	7.61	5.02	13.43	7.29	BN	1.25	2.22	3.57	2.16	D
1973	12.80	6.38	20.05	8.58	AN	1.87	4.48	6.47	3.50	AN
1974	21.69	9.78	32.50	12.99	W	2.43	4.53	7.12	3.90	W
1975	9.24	8.95	19.23	9.35	W	1.37	4.65	6.18	3.85	W
1976	4.63	2.75	8.20	5.29	C	0.78	1.07	1.97	1.57	C
1977	2.49	1.93	5.12	3.11	C	0.22	0.80	1.05	0.84	C
1978	14.90	8.12	23.92	8.65	AN	2.57	6.50	9.65	4.58	W
1979	6.06	5.64	12.41	6.67	BN	1.87	3.99	5.98	3.67	AN
1980	15.49	6.00	22.33	9.04	AN	3.74	5.41	9.47	4.73	W
1981	6.81	3.63	11.10	6.21	D	0.85	2.29	3.22	2.44	D
1982	20.56	11.82	33.41	12.76	W	3.78	7.00	11.41	5.45	W
1983	22.75	13.66	37.68	15.29	W	5.42	8.73	15.01	7.22	W
1984	15.98	5.52	22.35	10.00	W	3.51	3.48	7.13	3.69	AN
1985	6.24	4.00	11.04	6.47	D	1.11	2.41	3.60	2.40	D
1986	19.45	5.45	25.83	9.96	W	4.36	4.92	9.50	4.31	W
1987	5.85	2.80	9.27	5.86	D	0.55	1.48	2.08	1.86	C
1988	5.78	2.90	9.23	4.65	C	0.86	1.55	2.48	1.48	C
1989	9.03	5.07	14.82	6.13	D	1.07	2.42	3.56	1.96	C
1990	4.94	3.72	9.26	4.81	C	0.83	1.59	2.46	1.51	C
1991	3.90	4.01	8.44	4.21	C	0.56	2.57	3.20	1.96	C
1992	5.41	2.93	8.87	4.06	C	0.86	1.66	2.58	1.56	C
1993	12.44	8.98	22.21	8.54	AN	2.49	5.65	8.38	4.20	W
1994	4.55	2.73	7.81	5.02	C	0.66	1.80	2.54	2.05	C
1995	19.83	13.60	34.55	12.89	W	3.67	8.01	12.32	5.95	W
1996	13.05	8.37	22.29	10.26	W	2.57	4.51	7.22	4.12	W
1997	20.22	4.39	25.42	10.82	W	5.75	3.59	9.51	4.13	W
1998	17.65	12.54	31.40	13.31	W	2.82	7.11	10.43	5.65	W
1999	12.97	7.26	21.19	9.80	W	1.90	3.85	5.91	3.59	AN
2000	12.06	5.96	18.90	8.94	AN	1.98	3.78	5.90	3.38	AN
2001	5.64	3.46	9.81	5.76	D	0.92	2.23	3.18	2.20	D
2002	9.32	4.57	14.60	6.35	D	1.27	2.75	4.06	2.34	D
2003	10.71	7.74	19.31	8.21	AN	1.25	3.49	4.87	2.81	BN
2004	10.95	4.40	16.04	7.51	BN	1.51	2.25	3.81	2.21	D
2005	8.40	9.28	18.55	8.49	AN	2.73	6.28	9.21	4.75	W
2006	18.06	13.09	32.09	13.20	W	2.86	7.37	10.44	5.90	W
2007	6.59	3.04	10.28	6.19	D	0.99	1.46	2.51	1.97	C
2008	5.90	3.82	10.28	5.16	C	0.99	2.45	3.49	2.06	C
2009	7.05	5.30	13.02	5.78	D	1.51	3.35	4.94	2.72	BN
2010	7.45	7.78	16.01	7.08	BN	1.43	4.53	6.08	3.55	AN
2011	12.68	11.53	25.21	10.54	W	3.68	6.90	10.99	5.58	W
2012	5.69	5.46	11.84	6.89	BN	0.83	1.86	2.76	2.18	D
2013	8.52	3.01	12.19	5.83	D	1.33	1.67	3.05	1.71	C
2014	4.29	2.59	7.46	4.07	C	0.46	1.21	1.72	1.16	C
2015	6.95	1.77	9.27	4.01	C	0.66	0.74	1.43	0.81	C
min	2.49	1.77	5.12	3.11		0.22	0.74	1.05	0.81	
mean	10.98	6.47	18.26	8.19		1.95	3.81	5.95	3.29	
max	22.75	13.68	37.68	15.29		5.75	9.24	15.01	7.22	

1961-2010 mean

Eight River Runoff [maf]

WY	Dec	Jan	Feb	Mar	Apr	May
1901						
1902						
1903						
1904						
1905						
1906	0.55	3.69	2.93	7.00	5.34	6.43
1907	2.14	2.83	6.01	10.40	7.32	5.86
1908	1.43	2.27	2.12	2.19	2.53	2.59
1909	0.66	11.14	6.85	3.71	4.22	4.78
1910	3.09	2.90	2.55	4.84	4.21	3.30
1911	1.15	4.11	3.61	5.88	6.36	5.71
1912	0.55	1.20	0.94	1.61	1.58	3.33
1913	0.77	1.60	1.01	1.32	2.81	3.31
1914	1.72	8.50	3.99	4.18	5.05	5.28
1915	0.76	1.86	5.43	3.54	4.43	6.38
1916	1.52	3.75	4.89	5.71	5.03	4.44
1917	1.28	1.01	3.13	2.15	4.29	4.37
1918	0.70	0.57	1.22	2.99	3.09	2.53
1919	0.68	1.20	3.13	2.74	3.89	4.06
1920	0.68	0.57	0.58	1.71	2.58	3.20
1921	2.90	4.34	3.15	4.22	3.30	4.01
1922	1.16	1.07	2.63	2.41	3.66	6.68
1923	2.03	1.75	1.20	1.51	3.38	3.66

1924	0.49	0.56	1.16	0.64	1.07	1.10
1925	0.92	0.94	4.99	2.18	3.82	3.70
1926	0.67	0.76	3.18	1.73	3.79	2.18
1927	2.01	2.22	6.05	3.53	4.82	4.28
1928	1.10	1.37	1.94	5.69	3.73	3.02
1929	0.64	0.61	1.12	1.29	1.63	2.49
1930	2.37	1.41	1.84	2.78	2.64	2.29
1931	0.39	0.80	0.78	1.20	1.23	1.18
1932	1.68	1.33	1.84	2.50	2.73	4.16
1933	0.42	0.70	0.58	1.89	1.97	2.36
1934	1.04	1.47	1.59	1.90	1.61	1.09
1935	0.79	1.87	1.56	2.13	6.18	4.74
1936	0.51	3.22	5.04	2.77	3.83	3.71
1937	0.45	0.54	2.36	3.28	3.77	4.92
1938	4.81	1.86	5.27	7.50	5.98	7.34
1939	0.80	0.79	0.81	1.91	2.26	1.47
1940	0.68	3.88	5.68	6.22	4.61	3.77
1941	3.41	4.28	5.07	4.72	4.62	5.75
1942	3.58	4.18	5.10	2.23	4.64	4.76
1943	1.83	4.67	2.84	5.33	4.23	3.59
1944	0.55	0.78	1.44	1.94	1.88	3.34
1945	1.50	1.07	4.13	2.17	2.82	3.82
1946	4.60	2.64	1.31	2.29	3.45	3.68
1947	1.06	0.64	1.57	2.51	2.20	2.05
1948	0.50	1.91	0.70	1.56	4.34	4.51
1949	0.66	0.53	0.92	3.32	3.27	3.39
1950	0.43	1.82	2.54	2.46	3.74	3.73
1951	5.95	3.40	3.52	2.66	2.81	3.15
1952	3.36	3.48	4.03	3.68	6.35	7.51
1953	1.92	5.40	1.52	2.06	3.25	3.38
1954	0.80	2.20	2.84	3.66	4.56	3.27
1955	1.35	1.16	0.96	1.27	1.97	3.22
1956	9.14	7.52	3.71	3.07	3.51	5.24
1957	0.61	0.79	2.65	3.41	2.36	3.85
1958	1.62	2.39	7.61	4.71	6.04	6.74
1959	0.58	2.25	2.50	1.98	2.27	1.82
1960	0.47	0.90	3.15	3.22	2.50	2.39
1961	1.36	0.86	2.14	1.93	2.02	2.16
1962	1.19	0.78	4.08	2.39	3.89	3.14
1963	1.90	1.70	4.66	2.10	5.60	4.99
1964	0.85	1.55	1.01	1.15	1.92	2.44
1965	8.66	5.61	2.26	1.97	4.74	3.81
1966	1.04	1.85	1.56	2.52	3.33	2.52
1967	2.98	3.34	2.52	4.09	3.82	6.26
1968	0.85	1.49	3.71	2.55	2.17	2.15
1969	1.77	7.91	4.73	3.36	5.44	7.34
1970	3.30	10.68	3.02	3.12	1.82	2.77
1971	3.26	3.05	1.83	3.73	3.40	4.18
1972	1.19	1.40	1.73	3.30	2.52	2.61
1973	1.83	4.08	3.66	3.27	3.08	4.76
1974	3.68	6.93	2.10	6.18	5.07	4.69
1975	0.86	1.01	2.92	4.65	2.89	5.40
1976	0.76	0.65	0.88	1.34	1.35	1.44
1977	0.38	0.47	0.48	0.54	0.69	0.91
1978	1.90	5.91	3.48	5.36	4.40	4.70
1979	0.53	1.44	2.10	2.90	2.67	4.50
1980	1.24	6.89	5.93	3.62	3.11	3.67
1981	0.92	1.57	1.76	2.48	2.32	2.11
1982	5.58	3.50	5.57	4.74	8.05	5.68
1983	3.69	4.25	6.46	10.57	4.87	6.96
1984	6.72	2.85	2.29	3.08	2.50	3.60
1985	1.20	0.84	1.21	1.59	2.79	2.14
1986	1.25	2.62	11.55	7.09	3.19	3.56
1987	0.53	0.78	1.48	2.60	1.73	1.48
1988	1.70	1.84	1.01	1.26	1.48	1.59
1989	0.72	0.85	0.99	6.17	3.59	2.22
1990	0.45	1.27	0.88	1.84	1.80	1.77
1991	0.34	0.37	0.45	2.64	1.95	2.40
1992	0.47	0.58	2.41	1.99	2.17	1.33
1993	1.25	4.06	3.13	5.70	4.33	5.23
1994	0.78	0.78	1.23	1.49	1.57	1.79
1995	1.06	8.11	3.12	10.19	5.61	7.18
1996	1.72	2.47	6.25	4.25	3.97	5.50
1997	6.84	12.15	2.74	2.45	2.70	2.96
1998	1.18	5.19	7.44	5.11	4.53	5.53
1999	1.88	2.60	4.59	3.67	3.26	4.27
2000	0.65	2.55	5.49	4.08	3.55	3.62
2001	0.67	0.87	1.50	2.39	2.03	2.49
2002	2.50	2.70	1.74	2.31	2.82	2.60
2003	3.24	3.40	1.66	2.52	3.27	4.82
2004	2.14	1.90	3.98	3.47	2.64	2.29
2005	1.56	2.49	2.01	3.75	3.18	7.23
2006	5.83	5.16	3.42	5.38	8.56	6.84
2007	1.32	0.87	2.14	2.07	1.74	1.67
2008	0.70	1.70	1.81	1.79	1.89	2.68

2009	0.57	0.96	2.32	3.64	2.40	4.21
2010	0.71	2.48	2.31	2.31	3.25	3.70
2011	4.31	2.10	1.96	6.20	5.23	4.94
2012	0.49	0.96	0.74	3.03	3.70	2.27
2013	4.09	1.34	1.08	1.71	2.02	1.43
2014	0.38	0.36	1.22	2.05	1.71	1.18
2015	2.91	0.81	2.23	0.84	0.77	0.83
min	0.34	0.36	0.45	0.54	0.69	0.83
mean	1.95	2.99	2.95	3.45	3.23	3.68
max	9.14	12.15	11.55	10.57	8.56	7.51

1961-2010 mean

Official Year Classifications based on May 1 Runoff Forecasts

	Sacramento Valley Index		San Joaquin Valley Index	
WY	Index	Yr-type	Index	Yr-type
1995	12.4	W	5.5	W
1996	9.7	W	3.9	W
1997	11.0	W	4.2	W
1998	12.4	W	4.9	W
1999	10.0	W	3.4	AN
2000	9.2	W	3.3	AN
2001	5.9	D	2.3	D
2002	6.5	D	2.3	D
2003	8.0	AN	2.7	BN
2004	7.7	BN	2.2	D
2005	7.4	BN	4.2	W
2006	13.0	W	5.5	W
2007	6.2	D	1.9	C
2008	5.4	C	2.1	C
2009	5.5	D	2.4	D
2010	6.9	BN	3.5	AN
2011	10.0	W	5.1	W
2012	6.9	BN	2.2	D
2013	5.8	D	1.6	C
2014	4.0	C	1.1	C
2015	4.0	C	0.7	C

Abbreviations:

WY	Water year (Oct 1 - Sep 30)
W	Wet year type
AN	Above normal year type
BN	Below normal year type
D	Dry year type
C	Critical year type
% exc.	Probability in % that a given value will be exceeded
[maf]	Million acre-feet

Notes:

Unimpaired runoff represents the natural water production of a river basin, unaltered by upstream diversions, storage, export of water to or import of water from other basins.

Sacramento River Runoff is the sum (in maf) of Sacramento River at Bend Bridge, Feather River inflow to Lake Oroville, Yuba River at Smartville, and American River inflow to Folsom Lake. The WY sum is also known as the Sacramento River Index, and was previously referred to as the "4 River Index" or "4 Basin Index". It was previously used to determine year type classifications under State Water Resources Control Board (SWRCB) Decision 1485.

Sacramento Valley Water Year Index = 0.4 * Current Apr-Jul Runoff Forecast (in maf) + 0.3 * Current Oct-Mar Runoff in (maf) + 0.3 * Previous Water Year's Index (if the Previous Water Year's Index exceeds 10.0, then 10.0 is used). This index, originally specified in the 1995 SWRCB Water Quality Control Plan, is used to determine the Sacramento Valley water year type as implemented in SWRCB D-1641. Year types are set by first of month forecasts beginning in February. Final determination is based on the May 1 50% exceedence forecast.

Sacramento Valley Water Year Hydrologic Classification:

Year Type:	Water Year Index:
Wet	Equal to or greater than 9.2
Above Normal	Greater than 7.8, and less than 9.2
Below Normal	Greater than 6.5, and equal to or less than 7.8
Dry	Greater than 5.4, and equal to or less than 6.5
Critical	Equal to or less than 5.4

San Joaquin River Runoff is the sum of Stanislaus River inflow to New Melones Lake, Tuolumne River inflow to New Don Pedro Reservoir, Merced River inflow to Lake McClure, and San Joaquin River inflow to Millerton Lake (in maf).

San Joaquin Valley Water Year Index = 0.6 * Current Apr-Jul Runoff Forecast (in maf) + 0.2 * Current Oct-Mar Runoff in (maf) + 0.2 * Previous Water Year's Index (if the Previous Water Year's Index exceeds 4.5, then 4.5 is used). This index, originally specified in the 1995 SWRCB Water Quality Control Plan, is used to determine the San Joaquin Valley water year type as implemented in SWRCB D-1641. Year types are set by first of month forecasts beginning in February. Final determination for San Joaquin River flow objectives is based

on the May 1 75% exceedence forecast.
San Joaquin Valley Water Year Hydrologic Classification:

Year Type:	Water Year Index:
Wet	Equal to or greater than 3.8
Above Normal	Greater than 3.1, and less than 3.8
Below Normal	Greater than 2.5, and equal to or less than 3.1
Dry	Greater than 2.1, and equal to or less than 2.5
Critical	Equal to or less than 2.1

Eight River Index = Sacramento River Runoff + San Joaquin River Runoff
This Index is used from December through May to set flow objectives
as implemented in SWRCB Decision 1641.

The 'reconstructed' table is based on observed runoff, and does NOT show the
official year-types, which are based on May 1 forecasts of future runoff.
The current water year indices based on forecast runoff are posted at
http://cdec.water.ca.gov/water_supply.html and published in DWR Bulletin 120
(also available at http://cdec.water.ca.gov/snow/bulletin120)
These indices have been used operationally since 1995, and are defined in SWRCB
Decision 1641 (see http://www.waterrights.ca.gov/baydelta/d1641.htm)
This report is updated each fall once the data is available.

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Report name: Get report

ATTACHMENT J – PREPARED DIRECT TESTIMONY OF RICHARD McCANN, PH.D. ON MARGINAL COSTS, REVENUE ALLOCATION, AND RATE DESIGN ISSUES ON BEHALF OF THE AGRICULTURAL ENERGY CONSUMERS ASSOCIATION, A.13-04-012

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design. (U39M)	))))	A.13-04-012 (Filed April 18, 2013)

PREPARED DIRECT TESTIMONY OF RICHARD McCANN, PH.D ON MARGINAL COSTS, REVENUE ALLOCATION, AND RATE DESIGN ISSUES ON BEHALF OF THE AGRICULTURAL ENERGY CONSUMERS ASSOCIATION

December 13, 2013

744(c). To properly implement Section 744(c), PG&E should reduce its proposed rates for all tariffs but AG-1A and B (which will soon become defunct, as these ratepayers are expected to migrate to TOU rates as SmartMeters are employed), and AG-5B to at least the amount shown in Table AECA-3. All agricultural accounts will be on TOU rates next year and, therefore, should receive the discounted rate specified in Section 744(c). The Commission should direct PG&E to file agricultural tariffs that complies with Section 744(c).

TABLE AECA-3

Agricultural Rates Adjustments to Comply with PUC Sec. 744(c)

Rate Schedule	Type	PG&E's Average Proposed Rate	Minimum 744(c) Reduction	Maximum 744(c) Rate
AG-1A	NON-TOU	$0.25932		$0.25932
AG-RA	TOU	$0.22421	-$0.06403	$0.16018
AG-VA	TOU	$0.22274	-$0.06256	$0.16018
AG-4A	TOU	$0.24063	-$0.08045	$0.16018
AG-5A	TOU	$0.17480	-$0.01462	$0.16018
AG-1B	NON-TOU	$0.20034		$0.20034
AG-RB	TOU	$0.18112	-$0.02094	$0.16018
AG-VB	TOU	$0.18411	-$0.02393	$0.16018
AG-4B	TOU	$0.18813	-$0.02795	$0.16018
AG-4C	TOU	$0.18910	-$0.02892	$0.16018
AG-5B	TOU	$0.14291		$0.14291
AG-5C	TOU	$0.12961		$0.12961
System Avg.		$0.16018		

3.3. Agricultural Customers Should Have a Balancing Account to Smooth Large Annual Bill Fluctuations Due to Variations in Hydrological Conditions

Agricultural electricity demand varies tremendously with water conditions. Dry conditions both reduce surface water supplies and increase irrigation requirements. Farmers turn to increased groundwater pumping to replace decreased surface water supplies and meet heightened crop water needs. As a result, year-to-year agricultural electricity sales revenues likewise vary substantially with changes in groundwater pumping. Yet in the world of utility ratemaking, agriculture's assigned revenue responsibility is based on the assumption that average

water conditions will always prevail in the future, with no accounting for how expected variations will affect revenues collected over a number of years.

In other words, the counterfactual scenario that hydrologic variation does not exist has been and continues to be the basis for PG&E's GRC agricultural class revenue forecast. This premise adversely impacts growers' ability to budget and plan, year-to-year cash flow, and results in overcollection of revenues from the class on average.

Agricultural loads used for GRC revenue allocation in average water conditions can be calculated using PG&E's load forecasting model. The loads are weather-normalized by replacing the actual rainfall values in PG&E's model with the average rainfall values for forecasted years. Compliance with local, state and federal environmental laws and regulations (*e.g.*, Bay Delta water pumping restrictions, air quality regulations) prompted a one-time step increase in agricultural energy use. Regression analysis on agricultural loads from 2000 to 2012 shows a distinct step-up of aggregate loads of 15% in 2006 due to the combination of these factors. Once these items are factored in, agricultural loads are again declining on a normalized basis. The correction for normalized loads, which raises 2011 loads due to unusually wet conditions in that year, shows that agricultural loads are projected to decrease at 1.4% per year.

Based on these normalized years, two cases for revenues in the counterfactual scenario were calculated under the assumptions that 1) the average rate would remain unchanged; and 2) the average rate is influenced by the amount of usage. Negative correlation is readily apparent between the Water Index and the difference in what the revenues would have been in an average year. Notably, high payments to PG&E are associated with years in which growers are most financially stressed by poor water conditions.

Table AECA-4 shows the total revenues for the years 2001-2012 for actual sales and for the two cases of the counterfactual scenario. On average, PG&E has collected $7 to $9 million per year more than the class' projected GRC revenue responsibility. In 2012 alone, the excess revenues amounted to between $116 and $199 million. This is more than 20% of the agricultural class' revenue requirements in the GRC. Over the ten-year period from 2003 to 2012, the net present value of the excess revenues is $81 to $274 million. The bottom line is that on net, agricultural customers have been paying more than their fair share of revenues due to PG&E's failure to appropriately account for the variations predictably associated with the class.

Table AECA-4

	REVENUE SCENARIOS			Annual Difference	
Year	Actual	Actual Rate x Normalized Sales	Computed Rate x Normalized Sales	Actual – (Actual Rate x Normalized Sales)	Actual – (Computed Rate x Normalized Sales)
2001	$484.9	$493.9	$422.9	$(9.0)	$ 62.0
2002	$550.8	$567.8	$508.9	$(16.9)	$ 41.9
2003	$507.0	$555.9	$523.7	$(48.9)	$(16.8)
2004	$490.6	$466.4	$521.5	$24.1	$(30.9)
2005	$444.5	$518.9	$578.5	$(74.4)	$(134.0)
2006	$483.8	$495.2	$528.8	$(11.5)	$(45.0)
2007	$665.2	$533.2	$508.9	$132.0	$156.3
2008	$729.1	$669.8	$731.7	$59.4	$(2.6)
2009	$770.1	$719.0	$777.4	$51.2	$(7.3)
2010	$735.8	$813.5	$791.7	$(77.7)	$(55.9)
2011	$692.1	$724.0	$774.7	$(31.9)	$(82.6)
2012	$901.2	$785.2	$702.3	$116.1	$199.0
Average Difference (2001-2012)				**$9.4**	**$7.0**
NPV (2003-2012)				**$273.8**	**$80.6**

The solution to this problem is to create a balancing account that credits or debits agricultural customers as part of the Annual Electricity True-up on a going forward basis. The beneficiaries of past overcollections are not clear without auditing PG&E's various balancing accounts over the years. In the most likely scenario, PG&E accrued additional revenues towards distribution investments beyond the Commission's allowed rate of return because those revenues

often do not have a balancing account. The generation related revenues are more likely to have been redistributed back to other ratepayers through the Energy Resource Recovery Account (ERRA) and Annual Energy True-up (AET) mechanisms. Until a full accounting can be provided, AECA proposes that an initial year's balancing account adjustment be made for 2014 equal to the annual average overcollection for the last 12 years, equaling $9.4 million.

4. AECA Proposes a Theoretically-Consistent Way of Identifying Marginal Costs for Revenue Allocation

Different proposals have been submitted to the Commission that purport to calculate marginal costs that reflect the differences in cost causality created by differences in customer class growth rates (some of which are discussed below). A customer class that is growing rapidly intuitively adds more cost burdens than one that is shrinking and whose needs can be met easily with the existing system. To date, the methods that have been proposed are either unsatisfactory or do not properly capture the effects of growth.

AECA has developed a set of innovative proposals that measure the cost impact of growth in a consistent and intuitive manner. At the core of each calculation is the principle that faster growth accelerates the need for new resources. The value of that acceleration can be measured using the time value of money (or the discount rate) to calculate how the resource cost increases when it is needed sooner. Assuming a 10% discount rate, if a resource is acquired one year earlier, its cost increases by 10%. If that resource acquisition is deferred by one year, its cost decreases by 10%.

AECA's calculations assign to each class its responsibility for accelerating or deferring the need for new generation, distribution and customer access services based on the differences in growth rates. For example, if the system load is increasing at 1% a year, and the residential class represents 50% of the load and is increasing at 2% a year, then the residential class is

ATTACHMENT K – PG&E ELECTRIC RULE NO. 17.1

ELECTRIC RULE NO. 17.1 Sheet 1
ADJUSTMENT OF BILLS FOR BILLING ERROR

A. BILLING ERROR DEFINED

Billing error is the incorrect billing of an account due to an error by PG&E, the energy service provider (ESP), or its agents, or the Customer which results in incorrect charges to the Customer. Billing error includes, but is not limited to, incorrect meter reads or clerical errors, wrong daily billing factor, incorrect voltage discount, wrong connected load information, crossed meters, an incorrect billing calculation, an incorrect meter multiplier, an inapplicable rate, or PG&E's and/or the ESP's failure to provide the Customer with notice of rate options in accordance with Rule 12. Billing error shall also include errors or failures of PG&E, an Energy Service Provider (ESP), or its agent, to properly edit and validate meter data into bill quality data pursuant to meter data processing standards and protocols adopted by the Commission.

Field error, including, but not limited to, installing the meter incorrectly and failure to close the meter potential or test switches, is also considered billing error.

Billing error which does not entitle the Customer to a credit adjustment includes failure of the Customer to notify PG&E of changes in the Customer's connected load, equipment or operation or failure of the Customer to take advantage of any noticed rate option or condition of service for which the Customer becomes eligible subsequent to the date of application for service.

Billing error shall also include failure to deliver a gas, electric or combined commodity bill, actual or estimate, in a timely manner in accordance with Rule 9.A. Failure to issue a bill due to a natural or man-made disaster such as a fire, earthquake, flood, or severe storms shall not be considered billing error for purposes of this Rule. (T)

B. ADJUSTMENT OF BILLS FOR BILLING ERROR

Where PG&E overcharges or undercharges a Customer as the result of a billing error, PG&E may render an adjusted bill to the Customer for the amount of any undercharge, without interest, and shall issue a refund or credit to the Customer for the amount of any overcharge, without interest, in accordance with the procedures and limitations set forth below. Such adjusted bill shall be computed as follows:

(Continued)

ELECTRIC RULE NO. 17.1 Sheet 2
ADJUSTMENT OF BILLS FOR BILLING ERROR

B. ADJUSTMENT OF BILLS FOR BILLING ERRORS (Cont'd.)

1. BILLING ERROR RESULTING IN OVERCHARGES TO THE CUSTOMER

a. RESIDENTIAL AND NONRESIDENTIAL SERVICE

If either a residential or nonresidential service is found to have been overcharged due to billing error, PG&E will calculate the amount of the overcharge, for refund to the Customer, for a period of three years. However, if it is known that the period of billing error was less than three years, the overcharge will be calculated for only those months during which the billing error occurred.

2. BILLING ERRORS RESULTING IN UNDERCHARGES TO THE CUSTOMER

a. RESIDENTIAL SERVICE

If a residential service is found to have been undercharged due to a billing error, PG&E may bill the Customer for the amount of the undercharge for a period of three months. However, if it is known that the period of billing error was less than three months, the undercharge will be calculated for only those months during which the billing error occurred.

b. NONRESIDENTIAL SERVICE

If a nonresidential service is found to have been undercharged due to a billing error, PG&E may:

i. bill the Customer for the amount of the undercharge for a period of three months if the Customer is a Small Business Customer, as defined in Rule 1; or (T)

ii. bill the Customer for the amount of the undercharge for a period of three years if the Customer is not a Small Business Customer, as defined in Rule 1. (T)

A Customer who qualified as a Small Business Customer based upon annual usage under Rule 1 during the period of the billing error, but exceeds the annual maximum usage as a result of applying the three-month back-billing to calculate annual usage shall be treated as a Small Business Customer under the Section B.2.b.i, above, for any undercharges.

However, if it is known that the period of billing error was less than three months or three years, as applicable, the undercharge will be calculated for only those months during which the billing error occurred. (T) (T)

ATTACHMENT L – USDA “FARM INCOME AND WEALTH STATISTICS”

Farm Income and Wealth Statistics

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Charts and Maps of U.S. Farm Balance Sheet Data Charts and Maps of U.S. Farm Income Statement Data Update and Revision History General Documentation

Documentation for the Farm Sector Cash Receipts Estimation Documentation for the Farm Sector Balance Sheet Documentation for the Farm Sector Financial Ratios

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Value added to the U.S. economy by the agricultural sector, 2000-2009
Nominal (current dollars)

California	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000
Value of crop production	19,207,897	18,894,518	20,397,222	20,936,846	22,837,295	23,618,255	23,868,539	25,540,905	26,257,217	27,130,410
Crop cash receipts	18,932,209	18,849,651	20,273,424	21,232,829	22,380,525	23,859,613	23,843,465	25,566,746	26,763,863	27,304,554
Cotton	578,961	676,782	598,175	914,064	601,455	842,289	581,682	664,841	632,516	405,151
Feed crops	553,613	668,847	634,278	607,824	677,774	758,791	682,550	891,684	1,537,284	901,632
Food grains	232,790	352,569	356,918	420,190	481,815	449,669	485,381	616,398	1,171,927	1,362,592
Fruits and nuts	7,051,385	7,052,488	7,710,002	7,945,315	9,505,230	10,904,790	10,280,120	11,081,509	11,280,173	12,246,760
Oil crops	38,255	28,315	18,906	27,799	23,142	18,673	20,708	25,541	42,611	58,291
Vegetables and melons	6,580,599	6,146,223	6,783,647	7,061,143	6,662,124	6,420,042	7,087,497	7,412,068	6,612,521	7,248,735
All other crops	3,896,606	3,924,427	4,171,498	4,256,494	4,428,985	4,465,359	4,705,527	4,874,705	5,486,830	5,081,393
Home consumption	10,637	12,403	9,549	6,843	16,544	18,388	32,310	20,270	27,397	12,584
Inventory adjustment	265,051	32,464	114,249	-302,826	440,226	-259,746	-7,236	-46,111	-534,042	-186,728
Value of animals and products production	6,295,508	7,397,839	6,321,169	6,942,033	8,775,465	8,512,145	7,669,011	10,789,257	10,442,206	7,799,507
Animals and products cash receipts	6,252,697	7,356,831	6,270,214	6,998,674	8,558,660	8,438,062	7,582,836	10,818,833	10,609,009	7,850,050
Dairy products, Milk	3,704,035	4,625,431	3,832,501	4,027,837	5,365,992	5,223,062	4,492,229	7,336,603	6,924,121	4,537,171
Meat animals	1,315,788	1,433,448	1,302,336	1,653,535	1,729,308	1,836,636	1,751,489	1,851,206	1,906,059	1,677,381
Miscellaneous livestock	254,174	262,082	264,894	293,253	228,247	227,462	231,024	284,445	400,526	481,003
Poultry and eggs	978,700	1,035,870	870,483	1,024,049	1,235,113	1,150,902	1,108,094	1,346,579	1,378,303	1,154,495
Home consumption	4,057	1,736	2,192	2,146	10,637	15,735	32,142	23,625	4,715	2,967
Inventory adjustment	38,754	39,272	48,763	-58,787	206,168	58,348	54,033	-53,201	-171,518	-53,510
Farm-related income	1,681,708	1,867,636	1,697,371	1,932,945	2,417,854	2,431,626	2,819,157	2,583,378	3,887,366	2,872,308
Forest products sold	NA	NA	NA	NA	NA	NA	NA	NA	18,300	4,879
Gross imputed rental value of farm dwellings	876,737	889,728	932,000	953,942	1,217,746	1,260,658	1,325,398	1,370,766	1,639,214	1,372,226
Machine hire and customwork	391,794	296,129	314,588	338,896	584,518	465,008	631,292	329,810	787,856	797,272
Other farm income	408,439	673,978	442,620	632,256	608,152	697,948	853,087	872,552	1,441,997	697,930
Total commodity insurance indemnities	NA	NA	NA	NA	NA	87,500	111,000	291,182	94,196	167,125

New Hampshire
New Jersey
New Mexico
New York
North Carolina
North Dakota
Ohio
Oklahoma
Oregon
Pennsylvania
Rhode Island
South Carolina
South Dakota
Tennessee
Texas
Utah
Vermont
Virginia
Washington
West Virginia
Wisconsin
Wyoming

Total commodity insurance indemnities	NA	NA	NA	NA	NA	87,599	111,908	204,182	94,196	167,135
Federal commodity insurance indemnities	NA	NA	NA	NA	NA	NA	NA	NA	92,872	166,107
Net cash rent received by operator landlords 2/	NA	NA	NA	NA	NA	NA	NA	NA	51,631	87,831
Value of agricultural sector production	27,185,113	28,159,993	28,415,762	29,811,823	34,030,613	34,562,026	34,356,707	38,913,540	40,586,789	37,802,225
Intermediate product expenses 1/	12,727,866	13,670,261	13,257,754	12,619,956	13,024,711	14,507,234	16,239,398	16,565,896	19,570,042	16,847,606
Farm origin	4,013,758	4,024,553	3,956,304	3,730,417	4,342,717	4,559,721	4,828,840	5,617,593	6,972,328	5,544,785
Feed purchases	2,666,250	2,528,561	2,562,445	2,239,998	2,780,001	2,860,001	3,049,998	3,870,000	5,080,000	4,000,000
Livestock and poultry purchases	601,613	619,786	533,549	620,417	712,716	709,720	708,845	677,596	512,328	574,785
Seed purchases	745,895	876,206	860,310	870,002	850,000	990,000	1,069,997	1,069,997	1,380,000	970,000
Manufactured inputs	2,918,804	3,260,958	3,028,028	2,912,689	2,973,004	3,656,090	4,068,462	4,099,864	4,892,109	4,181,585
Electricity	589,973	851,563	779,016	589,348	553,494	542,923	641,209	670,517	680,030	747,319
Fertilizer, lime, and soil conditioners	791,313	826,769	760,680	800,000	829,998	1,029,999	1,170,000	1,110,001	1,500,000	1,240,000
Pesticides	957,188	1,031,682	944,037	979,998	950,001	1,160,000	1,240,001	1,160,001	1,340,000	1,300,000
Fuel and oils	580,330	550,944	544,295	543,343	639,511	923,168	1,017,252	1,159,345	1,372,079	894,266
Other intermediate expenses 1/	5,795,304	6,384,750	6,273,422	5,976,850	5,708,990	6,291,423	7,342,096	6,848,439	7,705,605	7,121,236
Machine hire and custom work	738,304	707,713	926,876	848,335	692,464	700,320	663,925	637,761	821,714	699,997
Marketing, storage, and transportation	1,903,131	2,132,059	1,925,726	1,497,499	1,441,351	2,264,789	2,308,707	2,111,338	1,599,203	1,681,944
Repair and maintenance 1/	894,336	795,617	754,478	861,891	1,032,385	966,918	1,034,308	1,177,821	1,328,092	987,720
Miscellaneous expenses 1/	2,259,533	2,749,361	2,666,342	2,769,125	2,542,790	2,359,396	3,335,156	2,921,519	3,956,597	3,751,575
Total insurance premiums 4/	418,041	416,713	418,516	506,199	478,558	469,304	462,961	389,990	445,437	464,988
Federal commodity insurance premiums	NA	NA	NA	NA	NA	NA	NA	NA	59,110	81,847
Irrigation	NA	NA	NA	NA	NA	NA	NA	NA	458,674	389,500
Contract labor	1,143,570	1,635,114	1,425,365	1,630,663	1,495,039	1,564,550	1,407,974	2,043,677	2,350,979	1,732,992
Net government transactions	48,187	223,392	76,114	112,924	-176,415	-32,515	-295,811	-438,089	-523,301	-378,372
Direct government payments	688,967	882,216	645,973	735,305	478,375	703,629	530,177	478,229	435,144	568,080
Property taxes and fees 1/	640,780	658,824	569,859	622,381	654,790	736,144	825,988	916,318	958,445	946,452
Motor vehicle registration and licensing fees	39,547	43,505	29,296	62,380	64,789	56,094	65,989	56,317	58,445	66,452
Gross value added	13,361,864	13,078,010	13,808,757	15,674,128	19,334,448	18,457,728	16,413,524	19,865,878	18,142,467	18,843,256
Capital consumption 1/	1,048,263	1,077,008	1,099,705	1,105,663	1,198,581	1,299,990	1,347,022	1,393,891	918,586	787,935
Net value added	12,313,601	12,001,002	12,709,052	14,568,465	18,135,867	17,157,738	15,066,502	18,471,987	17,223,880	18,055,321
Factor payments to stakeholders 3/	6,746,702	6,754,116	6,505,993	6,664,276	6,776,491	7,305,180	7,330,394	6,960,593	7,791,412	8,722,327
Hired labor and non-cash employee compensation	4,930,681	4,927,743	4,692,653	4,703,545	5,098,377	5,530,307	5,461,928	5,158,263	5,529,021	6,097,008
Net rent paid to operator landlords	NA	NA	NA	NA	NA	NA	NA	NA	83,623	123,906
Net rent paid to nonoperator landlords	422,035	527,025	515,642	833,954	588,542	498,995	419,490	282,467	481,924	714,084
Total interest expenses 1/	1,393,986	1,299,348	1,297,698	1,126,777	1,089,572	1,275,878	1,448,976	1,519,863	1,696,844	1,787,329
Net farm income	5,566,899	5,246,886	6,203,059	7,904,189	11,359,376	9,852,558	7,736,108	11,511,394	9,432,469	9,332,994

Footnotes

Data as of February 7, 2017
F = Forecast values.
NA = Data are not available/applicable.
Values are rounded to the nearest thousand.
1/ Includes expenses associated with operator dwellings
2/ Share rent income is included in cash receipts
3/ Prior to 2008 estimates, factor payments to stakeholders only includes net rent paid to nonoperator landlords.
4/ Includes federal and private crop and livestock insurance premiums as well as casualty, hail, motor vehicle and all other insurance premiums

USDA/ERS Farm Income and Wealth Statistics

Last updated: February 07, 2017

For more information contact: Farm Income Team

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Value added to the U.S. economy by the agricultural sector, 2010-2017F
Nominal (current dollars)

California	2010	2011	2012	2013	2014	2015
	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000
Value of crop production	28,393,148	31,034,347	34,230,775	38,157,805	39,902,672	34,564,862
Crop cash receipts	28,635,752	31,040,641	34,769,669	38,387,638	41,205,624	35,060,051
Cotton	511,644	838,518	825,381	827,368	853,134	445,071
Feed crops	952,109	1,535,503	1,488,170	1,366,737	1,491,948	1,023,964
Food grains	1,135,799	1,230,737	1,128,884	1,155,155	1,294,628	926,872
Fruits and nuts	13,913,684	15,214,393	18,755,871	21,087,026	23,074,348	17,938,929
Oil crops	31,326	33,972	39,089	42,171	43,167	41,657
Vegetables and melons	6,772,679	6,773,663	6,589,768	7,837,330	8,258,731	8,853,956
All other crops	5,318,509	5,413,853	5,942,505	6,071,853	6,189,669	5,829,602
Home consumption	16,696	13,773	9,921	18,250	17,468	54,478
Inventory adjustment	-259,300	-20,068	-548,814	-248,083	-1,320,420	-549,667

Indiana
Iowa
Kansas
Kentucky
Louisiana
Maine
Maryland
Massachusetts
Michigan
Minnesota
Mississippi
Missouri
Montana
Nebraska
Nevada
New Hampshire
New Jersey
New Mexico
New York
North Carolina
North Dakota
Ohio
Oklahoma
Oregon
Pennsylvania
Rhode Island
South Carolina
South Dakota
Tennessee
Texas
Utah
Vermont
Virginia
Washington
West Virginia
Wisconsin
Wyoming

Value of animals and products production	9,759,358	12,345,736	12,076,636	12,751,950	15,208,538	12,096,759
Animals and products cash receipts	9,752,467	12,176,360	12,184,781	12,814,019	15,404,781	11,954,093
Dairy products, Milk	5,928,150	7,680,751	6,899,743	7,617,641	9,358,087	6,293,210
Meat animals	2,050,584	2,669,221	3,227,126	3,086,974	3,770,789	3,424,444
Miscellaneous livestock	462,745	478,791	549,754	500,874	594,393	533,738
Poultry and eggs	1,310,988	1,347,597	1,508,158	1,608,530	1,681,512	1,702,701
Home consumption	7,211	8,256	8,857	7,110	7,696	7,062
Inventory adjustment	-320	161,119	-117,002	-69,179	-203,940	135,603
Farm-related income	2,531,836	3,068,486	3,908,133	3,363,588	3,550,948	3,582,793
Forest products sold	1,280	1,379	9,496	10,756	14,357	7,550
Gross imputed rental value of farm dwellings	1,087,380	1,099,825	1,110,930	1,017,332	1,012,787	1,051,398
Machine hire and customwork	856,208	739,800	837,477	832,656	524,735	913,959
Other farm income	586,968	1,227,482	1,950,230	1,502,844	1,999,070	1,609,885
Total commodity insurance indemnities	135,160	107,666	167,866	134,566	379,656	622,615
Federal commodity insurance indemnities	130,771	101,897	131,364	124,799	345,840	534,029
Net cash rent received by operator landlords 2/	105,062	115,845	162,862	172,005	167,739	167,260
Value of agricultural sector production	40,684,343	46,448,568	50,215,545	54,273,343	58,662,157	50,244,414
Intermediate product expenses 1/	17,425,153	18,659,011	20,142,871	22,235,066	23,876,848	20,368,490
Farm origin	6,189,012	6,994,360	7,651,938	8,435,920	6,888,747	6,547,219
Feed purchases	4,430,000	5,110,000	5,490,000	6,170,000	4,750,000	4,050,000
Livestock and poultry purchases	779,012	814,360	821,938	805,920	798,747	967,219
Seed purchases	980,000	1,070,000	1,340,000	1,460,000	1,340,000	1,530,000
Manufactured inputs	4,419,716	4,765,874	5,278,882	5,787,134	7,002,518	6,085,322
Electricity	747,729	670,358	854,983	1,036,989	1,193,366	1,152,776
Fertilizer, lime, and soil conditioners	1,350,000	1,620,000	1,610,000	1,850,000	2,350,000	2,060,000
Pesticides	1,210,000	1,290,000	1,450,000	1,600,000	2,080,000	1,650,000
Fuel and oils	1,111,987	1,185,517	1,363,899	1,300,145	1,379,152	1,222,545
Other intermediate expenses 1/	6,816,425	6,898,776	7,212,050	8,012,012	9,985,583	7,735,950
Machine hire and custom work	806,741	689,574	967,413	1,084,889	1,728,992	879,141
Marketing, storage, and transportation	2,101,993	2,019,305	1,722,660	1,748,214	2,147,628	1,594,384
Repair and maintenance 1/	1,179,903	1,054,594	1,140,493	1,185,780	1,497,986	1,414,721
Miscellaneous expenses 1/	2,727,788	3,135,302	3,381,484	3,993,129	4,610,977	3,847,703
Total insurance premiums 4/	445,339	463,768	528,587	546,530	701,111	645,732
Federal commodity insurance premiums	65,370	87,648	98,587	104,952	171,294	168,759
Irrigation	408,054	505,867	734,079	708,558	1,111,890	894,728
Contract labor	1,996,684	2,332,662	2,431,450	2,206,591	3,574,385	3,137,446
Net government transactions	-653,638	-843,530	-773,962	-849,064	-870,458	-912,269
Direct government payments	363,654	259,063	287,532	248,711	246,649	235,434

Direct government payments	363,054	259,063	287,532	248,711	246,649	235,434
Property taxes and fees 1/	1,017,292	1,102,593	1,061,494	1,097,774	1,117,107	1,147,703
Motor vehicle registration and licensing fees	87,292	62,593	61,494	67,774	67,107	67,703
Gross value added	20,608,868	24,613,365	26,867,262	28,982,623	30,340,466	25,826,208
Capital consumption 1/	1,094,519	1,134,109	1,882,989	2,128,923	2,864,952	2,048,527
Net value added	19,514,349	23,479,256	24,984,273	26,853,700	27,475,513	23,777,682
Factor payments to stakeholders 3/	8,631,231	7,822,206	8,890,398	9,570,642	9,289,605	9,147,018
Hired labor and non-cash employee compensation	6,023,316	5,147,338	5,848,550	6,643,409	6,145,615	6,102,554
Net rent paid to operator landlords	131,447	150,782	214,056	218,284	278,189	250,470
Net rent paid to nonoperator landlords	757,538	868,971	1,233,623	1,257,987	1,331,584	1,198,902
Total interest expenses 1/	1,718,931	1,655,115	1,594,168	1,450,963	1,534,218	1,595,093
Net farm income	10,883,118	15,657,050	16,093,876	17,283,057	18,185,908	14,630,664

Footnotes

Data as of February 7, 2017
F = Forecast values.
NA = Data are not available/applicable.
Values are rounded to the nearest thousand.
1/ Includes expenses associated with operator dwellings
2/ Share rent income is included in cash receipts
3/ Prior to 2008 estimates, factor payments to stakeholders only includes net rent paid to nonoperator landlords.
4/ Includes federal and private crop and livestock insurance premiums as well as casualty, hail, motor vehicle and all other insurance premiums

USDA/ERS Farm Income and Wealth Statistics

Last updated: February 07, 2017

For more information contact: Farm Income Team

Agricultural Account Aggregation Study

Report by Pacific Gas and Electric Company
March 7, 2014

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Executive Summary

In this report, Pacific Gas and Electric Company provides a summary of agricultural account aggregation from the utility perspective. Concurrently, in a separate report, the Agricultural Consultants provide the summary of account aggregation from the customer perspective. The Commission ordered PG&E and the Agricultural Consultants to conduct a joint agricultural account aggregation study as part of a settlement in PG&E's 2011 General Rate Case Phase II proceeding on marginal cost, revenue allocation, and rate design.

The Agricultural Consultants recruited a sample of 12 agricultural customers, each having multiple meter sites, into the study. The purpose of the study was to examine the extent to which the customers' bills in terms of dollars, and demand in kilowatts, would be reduced by billing each meter site based upon its demand only at the time of the combined peak demand of the aggregation group, as opposed to billing each meter at its individual maximum demand. The study clearly shows that billing demand is reduced for participating customers. Assuming that a consistent set of rates is utilized for this study, a reduction in billing demand also results in a bill reduction to the customer. This result was expected since the only cases where there would not have been a reduction in billing demand are those where customers operated their loads such as pumps simultaneously. Before account aggregation can be implemented as a tariff option, however, careful consideration should be given to the effect this program would have on non-participating and/or non-benefiting customers.

Chief among the considerations for non-participating or non-benefiting customers would be whether their rates would be increased if an agricultural account aggregation option were offered. This question hinges on PG&E's cost of service. If the lower revenue generated by an account aggregation program reflects a reduction in the cost to serve the agricultural class, then rates paid by other customers would not need to be increased to compensate for the revenue reduction. However, if it was determined that the cost of service for participants was not lower by the amount of the benefit those participants received, then rates for non-participating/non-benefiting customers would likely need to be increased.

PG&E does not conclude in this report whether or not account aggregation should be offered. Instead, PG&E sets forth a framework for the evaluation of an account aggregation program. PG&E reserves the right to provide additional policy considerations or analysis in rebuttal testimony.

I. Procedural Background

In Pacific Gas and Electric Company's (PG&E or the Company) 2011 General Rate Case (GRC) Phase II proceeding (A.10-03-014), the Agricultural Energy Consumers Association (AECA) submitted testimony which proposed that PG&E "develop and adopt virtual master metering programs and associated tariffs, to enable growers to aggregate the load used by multiple accounts on a single ranch or farm."[1] As part of a comprehensive agricultural rate design settlement in that proceeding, PG&E, AECA, the California Farm Bureau Federation (CFBF), the South San Joaquin Irrigation District (SSJID), and the Energy Producers and Users Coalition (EPUC) resolved not to adopt an agricultural account aggregation tariff, but to instead conduct a study. Decision 11-12-053 adopted the settlement, ordering PG&E to file the study in its 2014 GRC Phase II proceeding:

> "The Settlement does not adopt an agricultural aggregation tariff as proposed by AECA. Instead the Settling Parties agree to facilitate an Agricultural Settlement Account Aggregation Study (Study), to be completed by the second quarter of 2013. The Study will obtain data and other information on agricultural customers' electrical usage to allow evaluation of agricultural account aggregation. The scope, framework and methodology for the Study have been expressly agreed to by PG&E, AECA, CFBF and SSJID and are set forth in detail in Exhibit C and related Appendices 1 – 4 of the Settlement." (Decision 11-12-053, page 61.)

For this study, PG&E was required to do the following:

- Gather 15-minute interval data for the accounts of each participating customer for the period of the study.
- Calculate the billing determinants and bills for these customers under the status quo (i.e. current rates and tariffs).
- Calculate the billing determinants and bills for these customers if the metered accounts were aggregated.

In addition to the requirements above, the settlement gave PG&E the opportunity to "analyze the Study data from the utility perspective."

Section II of this report describes PG&E's methodology for calculating the billing determinants and bills described above.[2] Section III summarizes the study participants' bill savings that are

[1] Dr. Richard McCann prepared testimony on behalf of AECA *(Prepared Direct Testimony of Richard McCann, PhD, On Marginal Costs, Revenue Allocation, and Rate Design Issues, On Behalf of the Agricultural Energy Consumers Association)*, December 13, 2013, page 46.

[2] The bills, billing determinants, interval counts, and other underlying data used to calculate the results in this report are available to parties who provide executed non-disclosure agreements (NDA's) that are specifically for this study. The account aggregation NDA can be found in Appendix 3 to Exhibit C of the Agricultural Settlement.

attributable to account aggregation. Section IV discusses some considerations that PG&E believes that the Commission should take into account when evaluating an account aggregation policy.[3] Finally, the Appendix contains detailed technical descriptions of certain aspects of PG&E's analysis.

The results in Section III, along with the bills, billing determinants, and interval counts that are available upon signing an NDA, meet the compliance requirements set forth for PG&E in Paragraph 1C of the 2011 GRC Agricultural Settlement Agreement (Exhibit C).[4]

II. Methodology

In order to calculate billing determinants and bills for the study participants, PG&E performed the following steps (in consultation with the Agricultural Consultants):

1) gathered interval data for the study period,
2) defined "aggregation groups," where each group consists of 2 or more meter sites whose loads would be aggregated for the purpose of calculating bills; and
3) calculated bills and billing determinants for the meter sites in those groups.

These three steps are described in detail below.

1. Gather Interval Data

The Agricultural Consultants (M. Cubed, Economic Insights, and MRW), worked cooperatively with PG&E to perform or facilitate the following:

Customer Recruitment

- Identify a pool up to 50 possible study participants.

[3] PG&E's rebuttal testimony will respond to proposals for agricultural account aggregation that were presented in testimony served December 13, 2013. The purpose of this report on the agricultural account aggregation study is to explain what occurred in the study, present factual information, and satisfy compliance requirements in Exhibit C. Additional issues relevant to account aggregation may be addressed in rebuttal testimony.

[4] Paragraph 1C of Exhibit C was not altered through any subsequent modification. However, under the terms set forth in the original Settlement, the account aggregation study report was to be completed by the second quarter of 2013. CPUC Executive Director Paul Clanon, by letters dated April 10, 2013 and December 18, 2013, respectively granted delays in the report submittal date to December 31, 2013, and March 1, 2014. A first amendment to the agricultural settlement dated March 28, 2013 changed the study period from "up to 12 months commencing spring of 2012," to "up to 7 months commencing on or about April 1, 2013." The delay in the report submittal date to March 1, 2014 was also submitted in a joint Petition to Modify dated December 9, 2013 by PG&E, CFBF, and AECA, as corrected on December 13 and amended on February 6, 2014. The Petition to Modify is currently pending before the Commission. However, on February 27, PG&E and the Agricultural Parties requested a submittal delay from March 1 to March 7, which was granted by the Executive Director on March 3, 2014.

- Of that pool of possible participants, select a representative group of 15 customers.
- Obtain executed authorizations to release customer identity data and interval data.
- The above recruitment steps were performed by the Agricultural Consultants, with PG&E required to affirm that adequate interval data existed for the selected customers. After this process was completed, there were 14 customers. These customers were predominantly row crops or orchards, with 1 dairy.
- In response to suggestions by the Agricultural Consultants that as full a sample of participating meter sites from the selected customers be available for the study as possible, PG&E agreed to relax the settlement proscription that each customer be allowed only 5 to 15 meter sites, and that the total number of meter sites not exceed 150.[5]
- As a result, the 14 participating customers had a total of 482 meter sites requested for the study, ranging from a low of 3 to a high of 101 meter sites by customer.

Metering and Interval Data Collection

- PG&E determined that initially, approximately 268 of the requested 482 meter sites had the interval data capabilities needed for the study. PG&E undertook a focused field effort to install or enable interval meters where practicable, and worked with the Agricultural Consultants to determine the usefulness of all meter sites, resulting in a total of 358 meter sites with the interval capabilities needed for the study.
- PG&E collected 15-minute interval data on participating customers' electric usage.
- After secure data transfer protocols and platforms were established, a 13-month file covering March 2012 to March 2013 was sent in late April 2013. On the 10th of each month from May 2013 through November 2013, interval data for the prior calendar month was sent by PG&E to the Agricultural Consultants.
- PG&E worked with the Agricultural Consultants on how to concatenate the data and control for instances where the interval data provided was superseding, correcting, or replacing interval data previously sent.
- The entire recruitment and data collection process began in March 2012 and continued to October 2013, resulting in a possible 20 months of data for the study's 358 meter sites. Because this period coincided with ongoing large scale PG&E interval meter rollout deployment efforts, and because PG&E specifically installed approximately 102 new interval meters in January and February 2013 to accommodate study objectives, not all meter sites had complete data for the entire analysis period.

Customer Redefinition

- After consultation with the Agricultural Consultants, it was determined that, of the 14 customer entities mentioned in the 4th bullet point above, two of those entities should actually be considered a single customer entity for purposes of the study (because the two entities' operations were controlled by the same single entity), and a different pair should

[5] See *First Amendment to Supplemental Settlement Agreement on Agricultural Rate Design Issues in PG&E's Application 10-03-014*, dated March 28, 2013, and related documents.

also be considered a single customer entity (for the same reason). Both of these were merged into their respective "single entity."

- The result was a new total of 12 customer entities, with a total of 358 meter sites. These were the final data points used for PG&E's analysis.

2. Define Aggregation Groups

In order to perform its analysis of account aggregation and calculate bills and billing determinants, PG&E first needed to create a rule for determining which of the 358 individual meter sites fell into which "aggregation group" (i.e. the groups whose constituent meter sites' loads would be aggregated). After consultation with the Agricultural Consultants, PG&E developed the following rule: Meter sites would be considered part of an "aggregation group" if they both 1) belonged to the same customer entity, and 2) shared the same piece of distribution infrastructure. As described in detail in the appendix, PG&E performed this aggregation in two ways, at the substation and circuit level.

The tables below show how the 358 meter sites map to different aggregation groups (Table 1 corresponds to circuit-level aggregation, Table 2 to substation-level aggregation). The first column shows the group size (defined as the number of meter sites in an aggregation group), the second shows the number of aggregation groups of that size, and the third shows how many meter sites belong to groups of the size given in the first column. For example, when aggregation is performed at the circuit level, 24 meter sites are part of groups of size 3 (i.e. there are 24 / 3 = 8 such groups, of 3 meter sites each), and 35 meter sites are part of a group of size 35 (there is only 35/35 = 1 such group).

Table 1: Aggregation Groups at the Circuit Level

Size of group	Number of aggregation groups of that size	Number of meter sites belonging to groups of that size
1	19	19
2	10	20
3	8	24
4	7	28
5	3	15
6	5	30
7	6	42
8	2	16
9	1	9
10	3	30
12	3	36
13	2	26
14	2	28
35	1	35
Total	72	358

Table 2: Aggregation Groups at the Substation Level

Size of group	Number of aggregation groups of that size	Number of meter sites belonging to groups of that size
1	7	7
2	3	6
3	5	15
4	4	16
5	3	15
6	3	18
7	1	7
9	1	9
10	3	30
11	1	11
12	2	24
13	1	13
16	1	16
17	1	17
22	2	44
23	1	23
24	1	24
28	1	28
35	1	35
Total	42	358

As shown in Tables 1 and 2, there were 72 aggregation groups at the circuit level, and 42 aggregation groups at the substation level.

3. Calculate Billing Determinants and Bills

Next, PG&E (also in consultation with the Agricultural Consultants) formulated a method for aggregating the kW demands of each group's meter sites for purposes of calculating billing determinants and bills. The methodology was as follows: Each of the meter sites in an aggregation group would be billed on its existing applicable rate schedule[6], using all that schedule's applicable charges (i.e. for kW, kWh, and customer-months). However, under an account aggregation scenario, the *quantity* of kW used to calculate the demand bill for each meter site would change. Instead of each meter site receiving a demand charge based on the maximum load that individual meter site incurred (which is how demand bills are calculated

[6] All bill calculations were based on agricultural rates effective May 1, 2013.

under the status quo), the meter site would be billed based on its kW demand during the specific 15-minute interval at which the *combined* kW demand across *all* the meter sites (regardless of the sites' rate schedules) in the account aggregation group reached its maximum.

The 358 meter sites generally spanned all 13 agricultural rate schedules, including AG-1A, AG-1B, AG-ICE, AG-4A, AG-4B, AG-4C, AG-5A, AG-5B, and AG-5C. Only 1 site took service on AG-VA, 2 on AG-RA, and none on AG-RB or AG-VB. A description of these 13 rate schedules can be found in the Appendix, Section 3. Interval data for all meter sites in an account aggregation group was reframed to the same billing month, then evaluated based on the timing of the combined peak demands for the group as a whole, requiring relatively complex data processing methods.

For example, consider an illustrative aggregation group with 3 meter sites in it, with each of the meter sites on the AG-1B rate schedule (which has only a maximum demand charge). The graphs below show those 3 sites' loads in the month of January, and how the kW billing determinants would differ between the status quo (depicted in Figure 1) and an aggregation scenario (depicted in Figure 2). Please note that, although the example depicted in Figures 1 and 2 below uses 3 meter sites on the same rate schedule for purposes of explanation, meter sites in an aggregation group do not need to be on the same rate schedule in order to have their loads aggregated.

Figure 1: Status Quo Billing Scenario

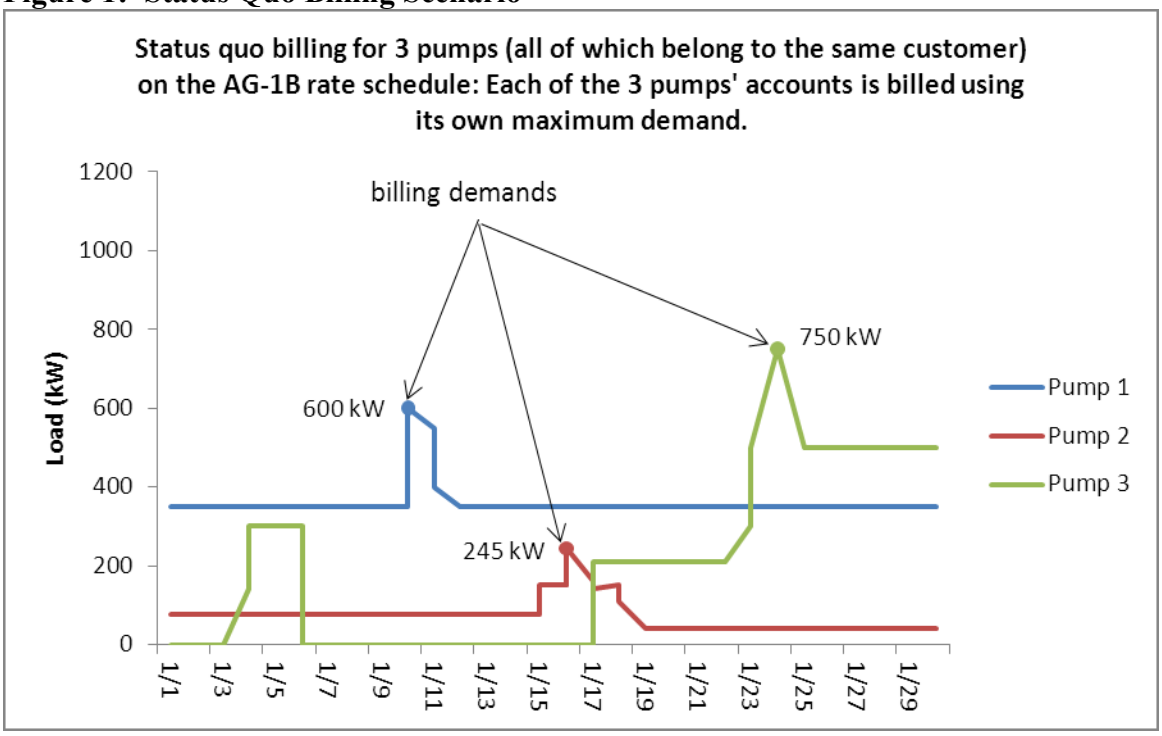
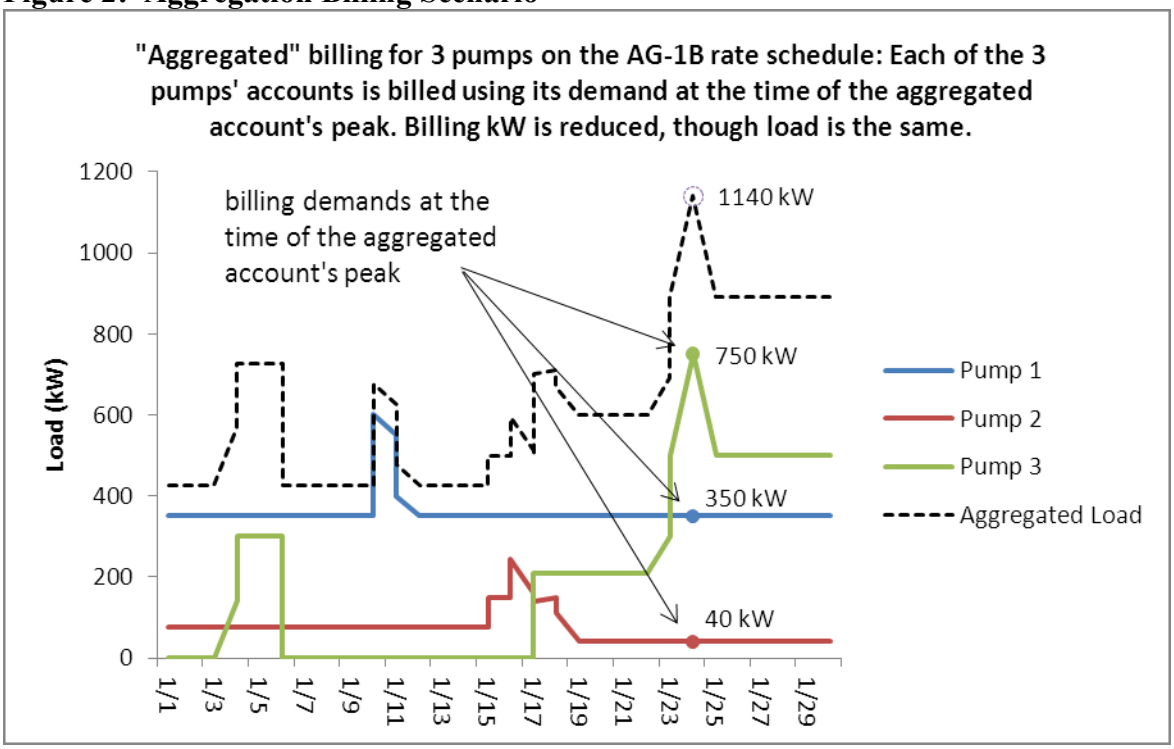


Figure 2: Aggregation Billing Scenario



Under the status quo, total billing kW is approximately 600 + 245 + 750 = 1,595 kW, whereas under an account aggregation scenario, total billing kW is approximately 750 + 350 + 40 = 1,140 kW.

The above example is illustrative; a more formal mathematical/technical description for how aggregation groups were defined and their bills calculated can be found in the appendix.

III. Results of Analysis

Table 3 below is a summary table showing the results of PG&E's analysis covering March 2012 through October 2013. The table shows each of the 12 customer entities' status quo average monthly bills (i.e. without aggregation), along with bill savings from account aggregation at the circuit level and the substation level.[7] As explained above, these bill savings are a result of reductions in each customer's billing demand; the table also provides percentage reductions in billing demand by customer entity.[8] All bill amounts and bill savings were calculated as if the

[7] The dollar amounts in columns 3, 4, and 5 are average monthly dollar amounts. In calculating these averages, PG&E excluded the data of months for which sufficient interval data was not available (less than 90% of possible intervals in a month).

[8] Please note that meter sites on the AG-A rate schedules have zero bill savings, as these sites are billed on connected load, not their actual kW maximum demand. For example, all of Customer 11's meter sites are on AG-A

agricultural rates effective May 1, 2013 were in effect during the entire March 2012 through October 2013 subject period.

Table 3: Aggregation Bill and kW Savings Summary

Customer Entity	Total meter sites owned by that customer	Status Quo Bills ($/month)	Savings under circuit-level aggregation ($/month)	Savings under substation-level aggregation ($/month)	% savings (circuit-level)	% savings (substation level)	% reduction in billing demand (circuit-level)	% reduction in billing demand (substation level)
Cust1	76	$ 154,788	$ (10,960)	$ (14,544)	-7.08%	-9.40%	-23%	-27%
Cust2	46	$ 134,221	$ (2,861)	$ (3,741)	-2.13%	-2.79%	-8%	-12%
Cust3	129	$ 388,156	$ (23,722)	$ (37,473)	-6.11%	-9.65%	-16%	-26%
Cust4	11	$ 11,601	$ (272)	$ (287)	-2.35%	-2.47%	-12%	-13%
Cust5	21	$ 79,588	$ (1,552)	$ (1,757)	-1.95%	-2.21%	-7%	-8%
Cust6	14	$ 11,639	$ (234)	$ (440)	-2.01%	-3.78%	-10%	-17%
Cust7	14	$ 5,136	$ (24)	$ (102)	-0.47%	-1.98%	-19%	-31%
Cust8	12	$ 26,989	$ (620)	$ (689)	-2.30%	-2.55%	-6%	-10%
Cust9	12	$ 36,145	$ (3,082)	$ (3,082)	-8.53%	-8.53%	-21%	-21%
Cust10	5	$ 3,862	$ (21)	$ (35)	-0.54%	-0.91%	-1%	-2%
Cust11	6	$ 2,247	$ -	$ -	0.00%	0.00%	-12%	-26%
Cust12	12	$ 749	$ (1)	$ (1)	-0.11%	-0.11%	-9%	-9%
TOTAL	**358**	**$ 855,121**	**$ (43,349)**	**$ (62,151)**	**-5.07%**	**-7.27%**	**-14.92%**	**-22.14%**

The results show that, in general, circuit level savings are less than substation savings because a larger number of meter sites can be aggregated at the substation level than at the circuit level (the greater the number of meter sites in an aggregation group, the greater the chance that some meter sites will be off or not operating at full capacity when the "aggregated account" peaks).

The results above in Table 3 reflect 20 months of data. However, as mentioned in Footnote 4 above, in March 2013 an amendment to the agricultural settlement was issued. This amendment changed the study period to "up to 7 months commencing on or about April 1, 2013." PG&E therefore also provides Table 4 below, which shows bill savings and demand reduction data for this "study period" of 7 months (on line 1), at both the circuit and substation level. For comparative purposes, PG&E also includes bill savings and demand reduction data for the other 13 "lead-in" months (from March 2012 to March 2013, on line 2), the entire 20-month period for which data was collected (line 3; this matches Table 3 above) as well as for summer and winter months (on line 4 and 5).

The data corresponds to the bill savings across all 358 meter sites, at both the circuit and substation level.

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rate schedules. This is why this customer has a non-zero reduction in demand due to aggregation, but zero bill savings.

Table 4: Aggregation Bill and kW Savings Summary for Alternate Study Periods

			Circuit-level Aggregation		Substation-level Aggregation	
	Period	Total Meter Sites	Monthly bill savings (%)	Demand Reduction (%)	Monthly bill savings (%)	Demand Reduction (%)
Line 1	Study period, April 2013 to October 2013	358	-4.37%	-14.44%	-5.40%	-20.89%
Line 2	"Lead-in" period, March 2012 to March 2013	358	-4.50%	-15.38%	-6.73%	-23.33%
Line 3	All 20 months (March 2012 to October 2013)	358	-5.07%	-14.92%	-7.27%	-22.14%
Line 4	Summer months within full 20-month period	358	-5.38%	-13.58%	-7.61%	-20.08%
Line 5	Winter months within full 20-month period	358	-3.49%	-19.20%	-5.40%	-28.73%

While the Line 5 winter kW demand reductions are generally the largest among all 5 lines in Table 4, the associated winter monthly bill dollar savings percentages are the lowest among all 5 lines. This is because winter demand charges are generally significantly below summer demand charge levels or unit prices per kW. Conversely, the Line 4 summer monthly bill dollar savings percentages are generally the highest among all 5 lines in Table 4, because summer demand charge levels or unit prices per kW are comparatively high.

IV. Considerations

PG&E has traditionally based demand charges on demands for individual meters. If implemented as a tariff option, aggregation would have the effect of billing multiple accounts owned by a single customer served by the same *defined* piece of distribution infrastructure by revising the kW demands of the individual meter sites used for billing purposes. As shown in the prior section, this could lower demand charges for customers who could or already have staggered (that is, diversified) the times at which load was incurred on the system. For example, if a customer has two accounts of the same size that run at the same time during the on-peak period, that customer could lessen their aggregated on-peak billing demand by one half by simply running those accounts during different hours of the on-peak period. This same demand aggregation concept could apply to any demand charge regardless of whether it is a time-of-use charge (or a non-time-of-use charge such as a maximum demand), or whether the charge was for transmission, distribution or generation.

In this section, PG&E identifies factors to consider in evaluating an aggregation proposal.[9]

[9] PG&E's positions on these factors and other considerations will be presented in rebuttal testimony.

A. Participant Perspective

In the agricultural class, charges are assessed for demand (per kW) for distribution and generation.[10] Distribution demand charges are established on a time-of-use basis (on-peak and part-peak), as well as "anytime" maximum demand charges, as applicable. Generation demand charges are generally assessed on a time-of-use basis (on-peak and partial-peak), as well as "anytime" maximum demand charges, as applicable. A customer with multiple accounts would achieve maximum aggregation savings by assuring accounts do not operate at the same time. When compared to the manner in which demand charges are assessed today (based on individual metered loads), aggregation would reduce the individual customer's revenue requirement responsibility. That is, a customer's billing demand would always be lowered through aggregation if a customer operates its accounts such that they are not running in the same hour. Only customers that either have only one account or customers with multiple accounts that must run at the same time would fail to have a lower billing demand.

To calculate the results in Part III, metered loads were aggregated for purposes of billing. This aggregation assumed no load shifting; therefore one could expect that these quoted savings would be achieved with minimal or no effort by the customer. Conversely, the customer might further reduce *its* billing demand and demand charges if its operations currently occurring simultaneously were separated into different hours under an account aggregation program.

Table 5 below splits the bill savings reported in Columns 4 and 5 of Table 3 in Part III, "Results of Analysis," into distribution and generation components. For example, Customer 1 would have saved a total of $10,960 per month (shown in Column 1 below) when aggregating his accounts at the circuit level. These total savings are then broken down into savings in terms of distribution and generation demand charges, in Columns 2 through 7. Similarly, Customer 1 would have saved a total of $14,544 per month when aggregating his accounts at the substation level, which is also broken down into distribution and generation demand charges in Columns 2 through 7. The rates used to obtain the generation revenue breakouts and the distribution level breakouts were the agricultural rates effective May 1, 2013. If, as discussed in the sections below, rates must be increased to fund the cost of these bill reductions, the savings below would need to be revised to reflect the updated rates.

[10] In the commercial and industrial sector, demand charges are also assessed for transmission service, and are subject to Federal Energy Regulatory Commission (FERC) jurisdiction and ratemaking. Transmission service for agricultural customers is assessed on a per kWh basis, and generally consists of transmission, transmission rate adjustments, and reliability service charges.

Table 5: Component Distribution and Generation Aggregation Bill Savings Dollars

		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7
			Distribution revenue reduction			Generation revenue		
		Total Savings	on-peak demand charge revenues	part-peak demand charge revenues	maximum demand charge revenues	on-peak demand charge revenues	part-peak demand charge revenues	maximum demand charge revenues
CIRCUIT	Cust1	$ (10,960)	$(1,371)	$ (90)	$ (5,778)	$(1,901)	$ (87)	$(1,733)
	Cust2	$ (2,861)	$ (396)	$ (50)	$ (1,389)	$ (591)	$ (48)	$ (386)
	Cust3	$ (23,722)	$(3,502)	$ (814)	$(10,325)	$(5,245)	$ (722)	$(2,178)
	Cust4	$ (272)	$ (34)	$ -	$ (146)	$ (44)	$ -	$ (48)
	Cust5	$ (1,552)	$ (237)	$ (53)	$ (679)	$ (385)	$ (51)	$ (147)
	Cust6	$ (234)	$ (29)	$ -	$ (128)	$ (35)	$ -	$ (42)
	Cust7	$ (24)	$ (3)	$ -	$ (13)	$ (4)	$ -	$ (4)
	Cust8	$ (620)	$ (76)	$ -	$ (326)	$ (111)	$ -	$ (107)
	Cust9	$ (3,082)	$ (459)	$ (95)	$ (1,475)	$ (652)	$ (74)	$ (328)
	Cust10	$ (21)	$ (3)	$ -	$ (11)	$ (3)	$ -	$ (4)
	Cust11	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Cust12	$ (1)	$ -	$ -	$ (1)	$ -	$ -	$ (0)
SUBSTATION	Cust1	$ (14,544)	$(1,808)	$ (99)	$ (7,672)	$(2,540)	$ (95)	$(2,331)
	Cust2	$ (3,741)	$ (512)	$ (59)	$ (1,840)	$ (751)	$ (57)	$ (522)
	Cust3	$ (37,473)	$(5,339)	$(1,148)	$(16,239)	$(7,974)	$(1,031)	$(3,643)
	Cust4	$ (287)	$ (35)	$ -	$ (154)	$ (47)	$ -	$ (51)
	Cust5	$ (1,757)	$ (264)	$ (57)	$ (779)	$ (427)	$ (54)	$ (175)
	Cust6	$ (440)	$ (54)	$ -	$ (242)	$ (64)	$ -	$ (80)
	Cust7	$ (102)	$ (13)	$ -	$ (55)	$ (15)	$ -	$ (18)
	Cust8	$ (689)	$ (85)	$ -	$ (363)	$ (122)	$ -	$ (119)
	Cust9	$ (3,082)	$ (459)	$ (95)	$ (1,475)	$ (652)	$ (74)	$ (328)
	Cust10	$ (35)	$ (4)	$ -	$ (19)	$ (5)	$ -	$ (6)
	Cust11	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Cust12	$ (1)	$ -	$ -	$ (1)	$ -	$ -	$ (0)

Table 6 provides the bill savings in percentage terms. Each row will sum to 100 percent, ignoring rounding differences.

Table 6: Component Distribution and Generation Aggregation Bill Savings as a Percentage Of Overall Demand Charges

		Distribution revenue reduction			Generation revenue		
		on-peak demand charge revenues	part-peak demand charge revenues	maximum demand charge revenues	on-peak demand charge revenues	part-peak demand charge revenues	maximum demand charge revenues
CIRCUIT	Cust1	13%	1%	53%	17%	1%	16%
	Cust2	14%	2%	49%	21%	2%	13%
	Cust3	15%	4%	45%	23%	3%	10%
	Cust4	12%	0%	54%	16%	0%	18%
	Cust5	15%	3%	44%	25%	3%	9%
	Cust6	12%	0%	55%	15%	0%	18%
	Cust7	12%	0%	54%	16%	0%	18%
	Cust8	12%	0%	53%	18%	0%	17%
	Cust9	15%	3%	48%	21%	2%	11%
	Cust10	12%	0%	55%	14%	0%	18%
	Cust11	-	-	-	-	-	-
	Cust12	0%	0%	82%	0%	0%	18%
SUBSTATION	Cust1	12%	1%	53%	17%	1%	16%
	Cust2	14%	2%	49%	20%	2%	14%
	Cust3	15%	3%	46%	23%	3%	10%
	Cust4	12%	0%	54%	16%	0%	18%
	Cust5	15%	3%	44%	24%	3%	10%
	Cust6	12%	0%	55%	15%	0%	18%
	Cust7	12%	0%	55%	15%	0%	18%
	Cust8	12%	0%	53%	18%	0%	17%
	Cust9	15%	3%	48%	21%	2%	11%
	Cust10	12%	0%	55%	14%	0%	18%
	Cust11	-	-	-	-	-	-
	Cust12	0%	0%	82%	0%	0%	18%

B. Non-Participant Perspective

As discussed above and shown in Section III, aggregation would result in lower billing demand – even in the case where customers with multiple meter sites whose loads are already staggered take no further action. Before pursuing aggregation, the effect of this change in billing demand on rates for the class and for customers that cannot participate in or benefit from aggregation should be understood. There are three different possibilities described in the three scenarios below. PG&E believes that in order to properly set rates while offering an account aggregation program, the Commission would need to determine which of the scenarios below would apply, or if conditions exist where there are other possibilities that should be considered.

Scenario 1: Revised billing demands and revenues represent a better allocation of costs between customers within the class, but do not change the cost to serve the class. That is, demand rates would be increased for all customers in the class to compensate for the bill reductions to the participants.[11]

Scenario 2: Revised billing demands and revenues are consistent with a lower allocation of cost to the agricultural class. If it could be demonstrated that an aggregation-related reduction in billing demand more accurately reflected a lower cost of service for the class, the rates set for demand charges would not be increased as a result of the program and non-participating (or non-benefiting) customer rates would not be affected. An example of such a relationship can be postulated in time-differentiated energy rates for generation. Assuming time-of-use generation energy rates are set properly relative to cost, a shift of one kWh from on-peak to off-peak would create a bill reduction that would be consistent with a utility cost reduction. Assuming the bill reduction and cost reduction are commensurate, no increase in rates to make up the revenue difference would be required under this hypothetical in the following year.[12] However, such a potential cost reduction is not used to set rates in the initial year.

Scenario 3: As another possibility, aggregation could provide an incentive to reduce costs to the class in the future. For example, if customers are encouraged to stagger demands through an aggregation program, no immediate cost savings may be created, but there is a potential that the cost to the class could be reduced in future cost studies. Unlike the generation energy example provided above in Scenario 2, the resulting cost reduction would not be provided with a commensurate billing reduction but could be reflected in future cost studies that quantify the classes' contribution to peak loads. For example, if aggregation caused loads to be further

[11] According to PG&E's preliminary calculation, allowing agricultural customers to aggregate their accounts at the circuit level would cause a revenue shortfall of approximately $39 million, which is approximately 4.5% of all Ag revenues at May 1, 2013 rates. Such a shortfall would have to be recovered through balancing accounts (and therefore, spread to all classes), or by raising the $/kW demand charges of the agricultural class. This revenue shortfall must be taken into consideration when evaluating account aggregation.

[12] The following issues (without limitation as to issues yet to be identified) are beyond this paper, but would need to be explored and resolved: i) how to determine if cost savings would occur due to account aggregation, ii) the methodologies for identifying and quantifying them and determining their duration, and iii) potential dual participation or dual benefit possibilities. Further discussion may be presented in rebuttal testimony.

staggered such that the agricultural peak load contribution was reduced relative to other classes, a lower cost allocation to the agricultural class would result, all other things being equal, as discussed in the next sections below. However, in the near term (before this cost reduction would be confirmed), revenues to the class would be lower than cost-based levels absent an increase to demand rates to make up the shortfall. The resulting increase to rates to make up the shortfall would have the effect of increasing bills for non-participating customers.

C. Utility Cost

As discussed above, the impact on non-participating or non-benefiting customers will depend substantively on the utility's costs and how those costs would change if an aggregation program were implemented.

1. Peak Related Cost

In GRC Phase II proceedings, PG&E estimates the cost of service for each customer class. Peak related costs include generation and a portion of distribution capacity costs. Estimated unit marginal costs are multiplied by each customer classes' contribution to the peak on each system.

For generation, loads are measured relative to system peak load hours. The method employed by PG&E utilizes hourly load research data to determine the relative contributions by class to peak hourly loads. This approach is intended to capture efforts by customers to diversify or stagger the times that they operate their loads because they are based on individual metered loads at the time of or coincident with system peak hours.

Like generation, the methods employed by PG&E for primary distribution costs utilize hourly load research data to determine the relative contributions by class to peak hourly loads. This methodology is also intended to capture class diversity in the peak hours. In the case of primary distribution, however, peak load hours are those relative to local distribution system peaks. The peak load hours for primary distribution can vary significantly from generation system peak hours.

As stated above, PG&E's current costing methodology captures the diversity of the agricultural class (as it does for other customer classes) in terms of peak related generation and distribution loads.[13] However, a pricing program that causes further diversification of load could further reduce the cost responsibility of the agricultural class, all other things being equal, as described in Scenario 3 above. For distribution costs, meter sites were combined into aggregation groups by distribution circuit, and by substation as well, as only meter sites sharing the same distribution system infrastructure facilities have the potential to offer local distribution benefits. As a result, potential cost reductions for peak related distribution costs are likely to be customer and location

[13] PG&E currently estimates class contributions to system and local peaks by taking a stratified sample of customers from all customer classes, and then extrapolating from that sample to PG&E's population of customers. In order to more accurately capture and quantify class load diversity, PG&E is continuing to improve the quality of its load research sample and increase utilization of SmartMeter data for revenue allocation purposes.

specific. PG&E notes that care would need to be taken to ensure that further diversification of loads does not actually move these loads into peak load hours such that the cost to the class is increased. In addition, the impact of offering an aggregation program to all customer classes may alter the relative share of each customer class' contribution to generation and distribution peak loads.

2. Non-Peak Related Cost

Non-peak related distribution capacity costs include secondary distribution capacity costs and new business primary distribution capacity costs. These non-peak related distribution costs are, by definition, not diversified[14]. That is, PG&E employs the non-coincident demand of each customer class to assess the non-peak related cost responsibility for each customer class. The non-coincident demand is the sum of the estimated maximum demands for each customer meter, regardless of when that maximum occurs. While class level cost responsibility can be reduced by the overall reduction in demand (where the customer's single highest metered demand, as measured once during the year, is lower), an aggregation program cannot reduce this measure of cost responsibility because an aggregation program only incentivizes changing the timing of the individual demands (not the actual maximum demand of each metered site).

As mentioned previously meter sites were combined into aggregation groups by distribution circuit, and by substation as well, as only meter sites sharing the same distribution system infrastructure facilities have the potential to offer local distribution benefits To the extent that an aggregation program would allow PG&E to safely design its system for a permanent lower level of non-coincident load, a different measure of non-coincident loads may be appropriate. However, such benefits may be highly location and customer specific. For example, a customer with several meter sites on a single distribution circuit may be able to alter the need for additional capacity on that circuit by staggering load on that circuit, provided that load diversity was provided with certainty and permanence for planning purposes. However, a similar customer with just as many meter sites located on different distribution circuits would not be able to affect the need for additional capacity on any single circuit to the same extent.

[14] All generation capacity costs are considered peak-related.

Appendix

Appendix Section 1: Methodology for Calculating Aggregated Bills

PG&E calculated agricultural bills and billing determinants twice, using two different methods, one at the substation level, and one at the circuit level, for the 358 agricultural meter sites participating in the account aggregation study. These methods are described below.

Method 1

- Each of the 358 meter sites is connected to a substation, and belongs to one of the 12 agricultural customer entities that participated in the study (note: the variable denoting the customer entity in the dataset is CUST_CODE, which is the terminology that will be used below).

- Define an "aggregation group" as all of the meter sites that fulfill **both** of the following criteria: 1) they are on a given substation and 2) they share a given customer code. For each unique combination of [CUST_CODE] and [substation name], there is exactly 1 aggregation group.

  Note: If a given combination of [CUST_CODE] and [substation name] has only one meter site belonging to it, then this site is ineligible for demand aggregation, as there are no other sites with which to combine that meter site's load. Hence, the site's billing kW would not change.

  For example, suppose that there are 10 meter sites, distributed across 3 CUST_CODEs (A, B, and C) and 3 substations (X, Y, and Z), as shown in the table below.

Meter Site	CUST_CODE	Substation
1	A	X
2	A	X
3	A	Z
4	B	Y
5	B	Y
6	B	Y
7	B	X
8	B	Z
9	C	Z
10	C	Z

  There would be 3 aggregation groups, as shown in the table below. Note that meter sites

3, 7, and 8 are not included in this table. This is because these sites would be ineligible for demand aggregation, as they do not share their substation with any other meter sites having the same customer code. Their kW demand bills do not change in an account aggregation scenario.

Aggregation Group	CUST_CODE and Substation	Meter Sites in that Group
Group 1	AX	1,2
Group 2	BY	4,5,6
Group 3	CZ	9,10

- For each aggregation group, add the interval loads of all meter sites in that group to create an aggregated load profile. Mathematically, the operation can be described by the equation below:

$$X_{a,t} = \sum_{n=1}^{N_a} x_{n,a,t}$$

Where:

$x_{n,a,t}$ is the load on meter site n in aggregation group a at time t. Note that the value of n determines a, as each of the 358 meter sites are "mapped" to 1 of the 12 aggregation customer entities' respective aggregation groups.

N_a is the total number of meter sites in aggregation group a.

$X_{a,t}$ is the aggregated load for aggregation group a at time t.

- The summation over n is performed for all possible combinations of aggregation group a and time t. The result is an aggregated load profile $X_{a,t}$ for each aggregation group.

- Find the 15-minute interval t at which that aggregated load $X_{a,t}$ reaches its maximum during the following five TOU periods.[15]
    - Summer "anytime"
    - Summer on-peak
    - Summer part-peak
    - Winter part-peak

[15] In this step, PG&E made two simplifying assumptions. First, PG&E used the times of day listed in the E-20 tariff in order to define these five TOU periods. Second, where multiple maxes were found, PG&E used the first occurrence of that maximum.

- Winter "anytime"

- Use the load of each meter site belonging to the aggregation group *a* at the time of this 15-minute interval *t* (i.e. at the time *t* corresponding to max($X_{a,t}$)) to calculate demand bills.[16] As under normal billing, use only those TOU demands which apply to the rate schedule applicable to the individual meter site.

  For example, suppose that meter site n_1 takes service on the AG-5B schedule (which has a maximum "anytime" demand charge and an on-peak demand charge for the summer months), and belongs to aggregation group a_1. To calculate the demand bill of n_1 in the summer month of June, the following steps were performed:

  1) To calculate the "anytime" maximum demand charge:
     - Find the time *t* at which the maximum load of a_1 occurs in the month of June.
     - At this time *t*, find the kW load of n_1.
     - Use this kW load to bill n_1 for its maximum "anytime" demand charge in the month of June.

  2) To calculate the summer on-peak demand charge:
     - Find the time *t* at which the maximum load of a_1 occurs in the month of June, but only include those hours in June between 12 PM and 6 PM, Monday through Friday (the on-peak period).
     - At this time *t*, find the kW load of n_1 .
     - Use this kW load to bill n_1 for its summer on-peak demand charge in the month of June.

Method 2

PG&E performed a second analysis whose steps were identical to the Method 1 above, save for one difference: The meter sites were aggregated at the circuit, not substation, level.

[16] To determine "anytime" maximum kW's and TOU maximum kW's for billing purposes, PG&E used calendar months (rather than billing periods). This was necessary because the multiple meter sites in a given aggregation group would generally be on different meter reading or billing cycles, making the determination of combined maximum kW demands unworkable for billing purposes. Therefore, the billing determinants used here may differ from the true customer behavior or usage patterns.

Appendix Section 2: Generation Demand Revenues and Distribution Demand Revenues for the Agricultural Class

The agricultural class' share of demand charge revenues from each distribution and generation component demand charge for each agricultural rate schedule (based on current January 1, 2014 agricultural rates) is shown below in Tables 7a and 7b to provide a sense of the revenues potentially affected by agricultural account aggregation. Table 7a shows revenues collected through demand charges in dollar terms; Table 7b shows revenues collected through demand charges in terms of percentages of total schedule-level revenues. For example, as can be seen in Table 7a, bundled revenues for the AG-1A schedule at 1/1/2014 rates are $17,679,578. Of these revenues, $3,595,165 are collected through demand (or connected load, where appropriate) charges, representing approximately 20% of bundled revenues for the schedule. This $3,595,165 can be further broken out into revenues collected through distribution maximum demand charges ($2,944,589) and generation maximum demand charges ($650,576), which (as shown in Table 7b) represent about 17% and 4%, respectively, of bundled revenues for the schedule. Note that cells that are blacked out mean that revenues are not collected through a certain type of demand charge; for example, AG-1A has only maximum demand charges (really a connected load charge), so the "on-peak" and "part-peak" demand charge revenue cells are blacked out.

Tables 7a and 7b: Agricultural Class Distribution and Generation Demand Charge Revenue

Table 7a

				Revenues ($) collected through demand charges					
				Distribution			Generation		
Schedule	Bundled revenues for schedule at 1/1/14 rates	demand revenues for schedule at 1/1/14 rates	% of schedule-level revenues recovered through demand (or connected load) charges	on-peak demand charge revenues	part-peak demand charge revenues	maximum demand charge revenues	on-peak demand charge revenues	part-peak demand charge revenues	maximum demand charge revenues
AG-1A	$ 17,679,578	$ 3,595,165	20%			2,944,589			650,576
AG-RA	$ 4,519,915	$ 947,184	21%			759,629			187,555
AG-VA	$ 3,138,562	$ 630,697	20%			502,257			128,441
AG-4A	$ 73,899,258	$ 17,182,796	23%			13,917,111			3,265,685
AG-5A	$ 18,713,108	$ 3,393,342	18%			2,322,626			1,070,716
AG-1B	$ 48,195,924	$ 9,751,807	20%			7,892,236			1,859,571
AG-RB	$ 5,881,810	$ 1,577,344	27%	62,047		1,091,165	111,623		312,510
AG-VB	$ 2,903,888	$ 780,896	27%	44,240		515,763	90,964		129,928
AG-4B	$ 95,471,781	$ 25,944,683	27%	3,132,458		13,905,852	3,924,659		4,981,715
AG-4C	$ 11,863,027	$ 3,637,177	31%	658,213	303,678	1,655,316	799,363	220,607	
AG-5B	$ 517,018,376	$ 162,261,220	31%	18,983,874		82,980,460	30,739,355		29,557,532
AG-5C	$ 168,863,383	$ 50,816,604	30%	9,125,103	3,673,076	15,693,058	18,374,244	3,951,124	
TOTAL	$ 968,148,610	$ 280,518,917	29%	$ 32,005,934	$ 3,976,754	$ 144,180,060	$ 54,040,208	$ 4,171,731	$ 42,144,230

Table 7b

	Revenues collected through demand charges, as a % of schedule-level revenues					
	Distribution			Generation		
	on-peak demand charge revenues	part-peak demand charge revenues	maximum demand charge revenues	on-peak demand charge revenues	part-peak demand charge revenues	maximum demand charge revenues
AG-1A			17%			4%
AG-RA			17%			4%
AG-VA			16%			4%
AG-4A			19%			4%
AG-5A			12%			6%
AG-1B			16%			4%
AG-RB	1%		19%	2%		5%
AG-VB	2%		18%	3%		4%
AG-4B	3%		15%	4%		5%
AG-4C	6%	3%	14%	7%	2%	
AG-5B	4%		16%	6%		6%
AG-5C	5%	2%	9%	11%	2%	

Appendix Section 3: Description of Agricultural Rate Schedules

(From PG&E's 2014 GRC Phase II testimony, Chapter 8, Agricultural Rate Design)

TABLE 8-1
PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AGRICULTURAL ELECTRIC RATES

Line No.	Current PG&E	Average 2012 Number of Accounts	Description	Average 2012 Annual kWh Per Customer
1	AG-1A	29,296	Small Non-TOU	7,693
2	AG-1B	7,102	Medium Non-TOU	40,690
3	AG-4A	12,459	Small 2-Period TOU < 35 hp	14,181
4	AG-4B	8,631	Medium 2-Period TOU > 35 hp	61,375
5	AG-4C	1,395	Medium 3-Period TOU > 35 hp	56,350
6	AG-5A	3,821	Small 2-Period TOU < 35 hp	30,595
7	AG-5B	13,650	Large 2-Period TOU > 35 hp	185,379
8	AG-5C	1,857	Large 3-Period TOU > 35 hp	941,458
9	AG-RA	2,307	Small Split-Week 2-Period TOU < 35 hp	14,027
10	AG-RB	848	Medium Split-Week 2-Period TOU > 35 hp	46,824
11	AG-VA	1,667	Small Short-Peak 2-Period TOU < 35 hp	13,741
12	AB-VB	422	Medium Short-Peak 2-Period TOU > 35 hp	48,683
13	AG-ICE	1,933	Diesel Pumping Conversion Rate	190,400
14	Total	85,388		72,358

PACIFIC GAS & ELECTRIC COMPANY
2020 ERRA Forecast
PGE-Forecast_DR_CCA_002-Q23Atch01
ERRA Forecasts and Actuals: 2005-2018

		Energy Sales Forecasts (GWh) [a]		Peak Demand Forecasts (MW) [b]	
Line	Test Year	System	Bundled	System	Bundled
1	2005	81,562	72,896	17,837	16,174
2	2006	83,432	74,194	18,889	17,529
3	2007	84,836	77,481	19,314	18,206
4	2008	85,529	78,748	19,821	18,803
5	2009	87,759	81,680	20,674	19,734
6	2010	85,652	80,142	20,420	18,796
7	2011	85,853	76,881	20,012	17,624
8	2012	86,019	76,656	20,252	18,095
9	2013	85,303	74,795	20,282	18,013
10	2014	86,570	75,974	20,157	17,805
11	2015	86,482	74,544	20,023	17,556
12	2016	84,460	70,870	19,558	17,018
13	2017	81,679	65,404	18,559	14,758
14	2018	80,774	47,986	17,029	10,489

Notes:
[a] Energy sales forecasts are at the customer meter--does not include Transmission & Distribution losses and UFE
[b] Peak demand forecasts are at the generation meter--includes Transmission & Distribution losses and UFE

		Energy Sales Actuals (GWh) [a]		Peak Demand Actuals (MW) [b]	
	Test Year	System	Bundled	System	Bundled
15	2005	81,556	72,728	18,755	Data Not Available
16	2006	84,037	76,572	21,459	
17	2007	85,704	79,104	20,167	
18	2008	86,824	80,747	20,627	
19	2009	85,347	79,792	18,410	17,281
20	2010	84,078	77,900	19,286	18,364
21	2011	83,982	75,412	18,024	16,672
22	2012	86,286	76,718	18,707	16,843
23	2013	86,288	75,856	19,382	17,747
24	2014	86,383	74,886	17,638	16,327
25	2015	85,475	72,030	18,631	16,351
26	2016	83,115	68,792	18,236	15,957
27	2017	81,536	60,959	19,293	15,022
28	2018	79,959	48,629	17,370	11,301

Notes:
[a] Actuals from Rate Data Analytic's Normalized Billing datasets. Reflects updates to recorded billing information due to rebills, rebates and other billing irregularities. Not adjusted for the effects of weather.

[b] System peak demand from Line 17 operational data at the generation meter--includes Transmission & Distribution losses and UFE. Bundled peak demand from CAISO settlement data, grossed up 3% to account for Transmission losses and UFE to be consistent with forecast presentaiton. This data is not available for 2005 through 2008. Not adjusted for the effects of weather.

ATTACHMENT B

CONFIDENTIAL DATA RESPONSES
OMITTED FROM PUBLIC VERSION