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Notes of Pacific Gas and Electric Company
2015 IEPR Demand Forms for the California Energy Commission
April 13th, 2015
Docket 15-IEPR-03
FORM 4

Demand and Price Forms

1. Historic and Forecast Electricity Demand

Form 1.1a-b Retail Sales of Electricity by Class or Sector (GWh)

PG&E is providing the requested market sector data in the historic period through 2014. PG&E is presenting its sales data from the “elecfix database”, which is an analytic dataset that is continuously revised to account for rebates, rebills, and other types of billing irregularities. As such, the totals in this data set may not synch up identically with data provided in other forums (e.g., QFERs, Annual Power Report, etc.). Total retail sales are shown on Form 1.1a by customer class. Electric vehicles (EV) are shown as a separate column item although EV usage is actually embedded in customer class sales. Only residential and non-residential totals are available for recorded bundled sales data shown in 1.1b; however, PG&E does forecast bundled load by class.

In the forecast period 2015-2026, PG&E has included the effects of energy efficiency as described in Section 3.1 below. PG&E has also included the impacts of electric vehicles and distributed generation (DG), including rooftop solar (photovoltaic or PV). PG&E assumes there will be no reopening of direct access (DA). New this year, PG&E has developed a probabilistic departure forecast for community choice aggregation (CCA). Details on PG&E’s approach to CCA forecasting are outlined in detail in Form 4.

PG&E is requesting confidential treatment for various portions of Form 1.1 as discussed in the confidentiality applications submitted with these forms.

Form 1.2 Distribution Area Net Electricity for Generation Load

DA and CCA are replicated in Form 1.2 from 1.1b. PG&E has no reason, at this time, to expect a material change in departing municipal load. Losses are distribution, transmission, and unaccounted for energy for bundled, DA, and CCA customers (losses associated with BART loads are not included.) Column L, uncommitted energy efficiency impacts are described below. Column M does not include the effects of uncommitted energy efficiency (unmitigated for EE) but does include load reductions for customer self-generation.

PG&E is requesting confidential treatment for various portions of Form 1.2 as discussed in the confidentiality applications submitted with these forms.

Form 1.3 LSE Coincident Peak Demand by Sector (Bundled Customers)

PG&E's peak demand forecast is not produced via an end-use model and, therefore, is not built up from sector-level data. For this reason, in Form 1.3, we are only able to provide aggregate forecast data for bundled customer peaks. PG&E's bundled system peak is a July peak (PG&E system peaks for July and August are equivalent, but associated DA will be slightly different for each month). Bundled customer distribution losses are developed consistent with the distribution loss factor algorithms used in the Settlements process. Transmission losses and unaccounted for energy are assumed to be 2.5 percent and 0.5 percent, respectively consistent with resource adequacy counting rules. As in Form 1.1 and 1.2, the effects of customer energy efficiency programs and incremental customer self-generation programs in the period 2015 through 2026 are included in the forecast data.

PG&E is requesting confidential treatment for various portions of Form 1.3 as discussed in the confidentiality applications submitted with these forms.

Form 1.4 Distribution Area Coincident Peak Demand

DA / CCA losses are assumed to be 3.6 percent for distribution and 3 percent for transmission and unaccounted for energy. All assumptions are the same as described in Form 1.3, above.

PG&E is requesting confidential treatment for various portions of Form 1.4 as discussed in the confidentiality applications submitted with these forms.

Form 1.5 Peak Demand Weather Scenarios

Forecast data are provided for each of the temperature scenarios requested, except for the 1 in 40 scenario for which we currently do not have a multiplier. Scenario forecasts are produced by simulating the peak demand forecast model over varying assumptions of peak temperature conditions. All assumptions are the same as described in Form 1.3, above.

PG&E is requesting confidential treatment for various portions of Form 1.5 as discussed in the confidentiality applications submitted with these forms.

Form 1.6a Distribution Area Hourly Load

Certain load may be served by both wholesale and retail purchases. The wholesale portion of this load is shown in the column entitled "Other Load (Wholesale)." The retail load portion of this load is reflected in the bundled load column.

Total system load includes bundled and unbundled load, bundled and unbundled losses, and other load (wholesale).

Historical distribution losses for 2013 and 2014 are consistent with the distribution loss factor algorithms used in the Settlements process. Forecasted distribution losses for 2015 are based upon historical estimates of these losses.

Transmission losses and unaccounted for energy for historical and forecasted load are assumed to be 2.5 percent and 0.5 percent, respectively consistent with resource adequacy counting rules.

PG&E is requesting confidential treatment for various portions of Form 1.6a as discussed in the confidentiality applications submitted with these forms.

Form 1.6b Hourly Loads by Transmission Planning Subareas or Climate Zone (IOUs Only)

The breakdown shows the hourly load for various local areas; the sum of these local area hourly loads does not equal the Total System Load provided, as there is load within PG&E's total system area not represented in any one local area.

Total system load includes bundled and unbundled load, bundled and unbundled losses, and other load (wholesale).

PG&E is requesting confidential treatment for various portions of Form 1.6b as discussed in the confidentiality applications submitted with these forms.

Forms 1.7a, b, & c Local Private Supply by Sector or Class

PG&E does not examine this area in detail in developing its demand forecast. Currently, there are no reliable historical or forecast data that may be used to complete these tables.

2. Forecast Input Assumptions

Form 2.1 PG&E Planning Area Economic and Demographic Inputs

Inputs are drawn from Moody's Analytics December 2014 baseline projections for PG&E's service area economy.

Form 2.2 Electricity Rate Forecast

Electric rates shown here are not a PG&E rate forecast per se. Rather, PG&E uses a simplified methodology based on historical average class rates to drive each respective equation. The 2015 average rates are derived from the 2015 Annual Electric True-Up. Beyond 2015, rates are escalated by the annual change in the CPI from Moody's previously mentioned forecast, plus an additional one percent.

PG&E is requesting confidential treatment for various portions of Form 2.2 as discussed in the confidentiality applications submitted with these forms.

Form 2.3 Customer Count & Other Forecasting Inputs

Form 2.3 provides recorded and projected customer counts by customer class. The data reported is billing data (number of bills), which is used to represent number of customers. The annual numbers reported are averages of 12 months of customer data.

3. Other Notes

Form 8.2 Monthly Residential Sales by Percentage of Baseline

The completed submission (provided as 10 forms) is supplied in the excel workbook, one tab per baseline territory.

Note that the customer count represents the number of customer bills that contributed to the kWh shown in the corresponding tier. An individual customer bill may be counted multiple times in any month depending on the total kWh for that bill. For example, if a customer bill reached kWh equal to 30 percent of baseline usage during a month, then that bill would be counted three times—once in the 0 to 10 percent of baseline tier, once in the 10 percent to 20 percent of baseline tier and once again in the 20 percent to 30 percent of baseline tier.

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4. Demand Forecast Methods

PG&E uses an econometric approach with time series data to develop both its electricity consumption (energy) and peak demand (peak) forecasts. Post-regression adjustments are then made to capture the future effects of distributed generation, energy efficiency, electric vehicles, and community choice aggregation. PG&E's process for developing forecasts of energy sales and peak demand are shown in Figures 1 and 2.

Figure 1: Electricity Sales Forecast Process Map

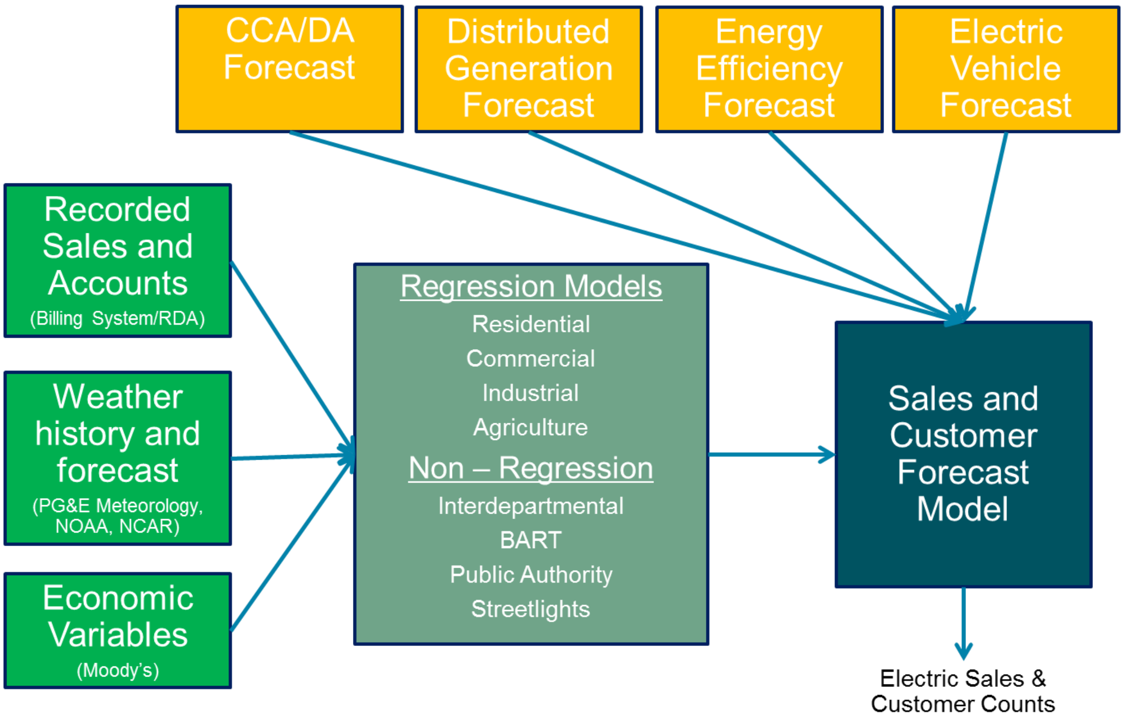
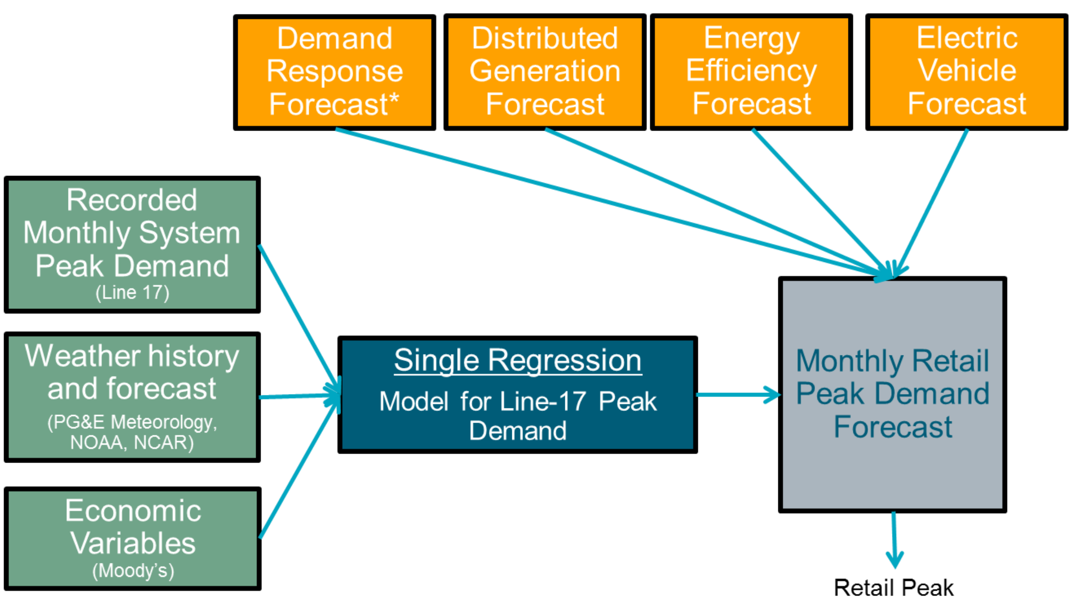


Figure 2: Electric Peak Forecast Process Map



*Non-Event-Based Demand Response Programs (e.g., TOU, Permanent Load Shifting)

PG&E develops its energy forecast by major customer class for the retail system, which includes sales to both bundled customers and non-utility procurement customers (e.g., Community Choice Aggregation (CCA), Direct Access (DA), and BART). Resale (wholesale) customer service, which at one time constituted a material level of demand, now amounts to just a very small amount of imbalance power.

The major customer classes for which PG&E uses an energy forecast to set rates are:

- Residential: Single family residences and separately billed units in multi-family structures.
- Small Commercial: Commercial business < 200 kW
- Medium Commercial: Commercial business < 500 kW
- Large Commercial & Industrial: Commercial business > 499 kW; Commercial / Industrial customer > 999 kW
- Agricultural: End use agricultural products + a few agricultural processing customers

The above customer classes account for about 98 percent of PG&E's annual electric usage. The remaining customers, BART, public authority, street lighting, and interdepartmental, account for the remainder. Municipal utility districts (e.g., Palo Alto, Alameda) and irrigation districts (e.g., Modesto, Merced) are excluded from PG&E's forecast of sales and peak, which is concerned solely with retail customer usage. Note also that PG&E forecasts peak demand at the retail area, not the Transmission Access Charge or TAC area. PG&E's retail area does not include Department of Water Resources, BART, Western Area Power Authority, or any municipally served territories.

PG&E constructs regression models with variables that drive the demand for electricity: economic/demographic, price, and weather, plus time series terms to assure no auto-correlation in the residuals. PG&E favors variables that are statistically significant predictors of energy demand; however, PG&E does not make that an absolute requirement so long as a variable is conceptually sound. The specific inputs vary from model to model, and are shown in greater detail below. Moody's Analytics provides economic and demographic history and forecasts. Weather inputs are drawn from PG&E's meteorological services and a National Center on Atmospheric Research (NCAR) study on future normal weather in PG&E service territory with climate change impacts.

Model Components

Equations for the four major customer classes (energy) and the system peak forecast are shown below:

Residential Accounts

Dependent Variable: D(RES_ACCTS)
Method: Least Squares
Date: 03/08/15 Time: 17:09
Sample: 2005M01 2014M11
Included observations: 119
Convergence achieved after 7 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
HH_PGE	0.963259	0.230003	4.188034	0.0001
AFFORD	-31.75486	10.17739	-3.120138	0.0023
JUN	6481.417	1725.037	3.757263	0.0003
AUG	5702.801	1722.038	3.311657	0.0012
OCT	-6535.445	1718.689	-3.802575	0.0002
SEP2014	-6534.674	2212.911	-2.952976	0.0038
AR(12)	0.573760	0.069919	8.206029	0.0000

R-squared	0.757821	Mean dependent var	2581.555
Adjusted R-squared	0.744847	S.D. dependent var	4344.602
S.E. of regression	2194.574	Akaike info criterion	18.28239
Sum squared resid	5.39E+08	Schwarz criterion	18.44586
Log likelihood	-1080.802	Hannan-Quinn criter.	18.34877
Durbin-Watson stat	2.049219		

HH_PGE = Households

AFFORD = Affordability metric

JUN, AUG, OCT = Monthly Dummies

SEP 2014 = Month dummy to clean regression results for outlier data point.

Residential Usage per Account
Residential Use Per Account

Dependent Variable: LOG(RES_SALES/RES_ACCTS_FORE)
Method: Least Squares
Date: 03/08/15 Time: 17:19
Sample (adjusted): 2001M02 2014M11
Included observations: 166 after adjustments
Convergence achieved after 8 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	5.776093	0.812504	7.108999	0.0000
LOG((RES_RATE/CPI_PGE)/ (REAL_PERS_INC_PGE/HH_PGE))	-0.026605	0.065902	-0.403700	0.6870
HDD_PGE	0.000500	4.17E-05	11.98675	0.0000
CDD_PGE	0.001886	0.000107	17.54594	0.0000
DEC2008	0.114504	0.015522	7.376902	0.0000
AR(1)	0.744909	0.058881	12.65098	0.0000
SAR(12)	0.923226	0.035329	26.13224	0.0000

R-squared	0.955081	Mean dependent var	6.319111
Adjusted R-squared	0.953386	S.D. dependent var	0.102742
S.E. of regression	0.022182	Akaike info criterion	-4.737792
Sum squared resid	0.078237	Schwarz criterion	-4.606564
Log likelihood	400.2367	Hannan-Quinn criter.	-4.684526
F-statistic	563.4479	Durbin-Watson stat	2.094849
Prob(F-statistic)	0.000000		

RES_RATE = Average residential class rate
CPI_PGE = Consumer Price Index (PG&E Territory)
REAL_PERS_INC_PGE = Real personal income (PG&E Territory)
HH_PGE = Number of households (PG&E Territory)
HDD_PGE = Heating Degree Days (PG&E Territory)
CDD_PGE = Cooling Degree Days (PG&E Territory)
DEC2008 = Month dummy to clean regression results for outlier data point.

Commercial Accounts

Dependent Variable: D(COM_ACCTS)
Method: Least Squares
Date: 03/08/15 Time: 17:49
Sample: 2001M01 2014M11
Included observations: 167

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	184.1312	44.53705	4.134338	0.0001
D(RES_ACCTS_FORE)	0.034486	0.007357	4.687461	0.0000
JAN2003	-3181.447	495.2551	-6.423855	0.0000
JAN2004	4319.046	464.1699	9.304883	0.0000

R-squared	0.522212	Mean dependent var	308.4311
Adjusted R-squared	0.513419	S.D. dependent var	661.1512
S.E. of regression	461.1885	Akaike info criterion	15.12915
Sum squared resid	34669254	Schwarz criterion	15.20383
Log likelihood	-1259.284	Hannan-Quinn criter.	15.15946
F-statistic	59.38528	Durbin-Watson stat	2.098655
Prob(F-statistic)	0.000000		

C = Constant

RES_ACCTS_FORE = residential accounts forecast

Jan2003 = Month dummy to clean regression results for outlier data point.

Jan2004 = Month dummy to clean regression results for outlier data point.

Commercial Usage per Account

Dependent Variable: LOG(COM_SALES/COM_ACCTS_FORE)
Method: Least Squares
Date: 03/08/15 Time: 18:03
Sample (adjusted): 2001M02 2014M11
Included observations: 166 after adjustments
Convergence achieved after 10 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	7.351585	0.263933	27.85393	0.0000
LOG((EMP_INFO+EMP_FIN+ EMP_TOT_SVC)/EMP_TOT_PGE)	-0.459566	0.260121	-1.766736	0.0792
LOG(COM_RATE/CPI_PGE)	-0.114819	0.020039	-5.729638	0.0000
CDD_PGE	0.000722	8.60E-05	8.400274	0.0000
AR(1)	0.473392	0.071403	6.629834	0.0000
SAR(12)	0.832585	0.041876	19.88197	0.0000

R-squared	0.922691	Mean dependent var	8.553559
Adjusted R-squared	0.920275	S.D. dependent var	0.061432
S.E. of regression	0.017346	Akaike info criterion	-5.235479
Sum squared resid	0.048139	Schwarz criterion	-5.122998
Log likelihood	440.5448	Hannan-Quinn criter.	-5.189822
F-statistic	381.9251	Durbin-Watson stat	2.152297
Prob(F-statistic)	0.000000		

C = Constant

EMP_INFO = Employment in information services (PG&E Territory)

EMP_FIN = Employment in financial services (PG&E Territory)

EMP_TOT_SVC = Total services employment (PG&E Territory)

EMP_TOT_PGE = Total employment (PG&E Territory)

Com_Rate = Average Commercial Class Rate

CDD_PGE = Cooling Degree Days (PG&E Territory)

Industrial Sales

Dependent Variable: IND_SALES
Method: Least Squares
Date: 03/08/15 Time: 18:45
Sample (adjusted): 2001M02 2014M11
Included observations: 166 after adjustments
Convergence achieved after 17 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	9.13E+08	1.10E+08	8.298538	0.0000
GDP_MANUF	10634.35	3659.742	2.905764	0.0042
CDD_PGE	861881.8	121702.6	7.081869	0.0000
DEC	-40667622	13297455	-3.058301	0.0026
OCCI_DUMMY	36898907	17658764	2.089552	0.0383
RECESSION	-49930936	22768713	-2.192963	0.0298
AR(1)	0.739757	0.055590	13.30739	0.0000
SAR(12)	0.455726	0.068599	6.643328	0.0000

R-squared	0.871866	Mean dependent var	1.26E+09
Adjusted R-squared	0.866189	S.D. dependent var	88094974
S.E. of regression	32225324	Akaike info criterion	37.46140
Sum squared resid	1.64E+17	Schwarz criterion	37.61137
Log likelihood	-3101.296	Hannan-Quinn criter.	37.52227
F-statistic	153.5830	Durbin-Watson stat	1.926619
Prob(F-statistic)	0.000000		

C = Constant

GDP_MANUF = Gross product of manufacturing (PG&E Territory)

CDD_PGE = Cooling Degree Days (PG&E Territory)

DEC = Monthly dummy for December

OCCI_DUMMY = dummy variable denoting the presence of Occidental Petroleum

RECESSION = Constructed variable to account for sales loss during the recession

Agricultural Sales

Dependent Variable: AG_SALES
Method: Least Squares
Date: 03/09/15 Time: 15:24
Sample: 2001Q1 2014Q4
Included observations: 56
Convergence achieved after 22 iterations
MA Backcast: 1999Q3 2000Q4

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	3.54E+08	32640681	10.83524	0.0000
RAIN1	-8738952.	1426476.	-6.126251	0.0000
RAIN2	-23987904	2330132.	-10.29465	0.0000
RAIN3	-16449012	2389872.	-6.882802	0.0000
@SEAS(2)	1.34E+09	83763155	16.02843	0.0000
@SEAS(3)	1.46E+09	78211806	18.72628	0.0000
@TREND	16229190	476478.8	34.06068	0.0000
MA(6)	-0.927730	0.021229	-43.70148	0.0000

R-squared	0.983591	Mean dependent var	1.27E+09
Adjusted R-squared	0.981198	S.D. dependent var	5.84E+08
S.E. of regression	80086417	Akaike info criterion	39.36667
Sum squared resid	3.08E+17	Schwarz criterion	39.65601
Log likelihood	-1094.267	Hannan-Quinn criter.	39.47885
F-statistic	411.0365	Durbin-Watson stat	1.605368
Prob(F-statistic)	0.000000		

C = Constant
RAIN1 = Constructed variable of rainfall in the 4th quarter
RAIN2 = Constructed variable of rainfall in the 4th + 1st quarters
RAIN3 = Constructed variable of rainfall in the 4th + 1st + 2nd quarters
@SEAS(2) = Dummy variable for quarter 2
@SEAS(3) = Dummy variable for quarter 3
@TREND = time trend variable

Post-Regression Adjustments

Expectations of future increases in sales loss to energy efficiency and distributed generation as well as sales gain due to electric vehicles is also incorporated into the forecast. For most of these policies, PG&E's approach is to compare the level of the program in the existing data with the program levels that are anticipated in the future, and to adjust the forecast accordingly. The assumptions are derived as follows:

- Conservation and Energy Efficiency: Navigant's 2013 DSM study that underlies the Mid-Case Additional Achievable Energy Efficiency (AAEE) forecast used by the IEPR 2013 and 2014 CED (See Form 6 for details)

- Distributed Generation & California Solar Initiative: PG&E internal analysis (see Form 6 for details).
- Electric Vehicles: PG&E internal analysis.
- Demand Response (Peak only): PG&E internal analysis (see notes for Form 6)

Incorporating Energy Efficiency and Distributed Generation in the Forecast

PG&E incorporates energy efficiency and distributed generation impacts in demand forecasting by performing a series of steps:

1. EE/DG savings data is gathered to find the average impacts during the regression period.

2. The average EE/DG impact is compared to future EE/DG savings projections in the forecast period.

3. If the future EE/DG impact is projected to be greater than past EE/DG impact, the forecast is decremented by the difference.

Incorporating Electric Vehicles in the Forecast

Since electric vehicles are a relatively new factor in the sales forecast, PG&E simply adds all expected EV sales and peak impact to the overall sales forecast. PG&E assumes 80 percent of EV sales register in the residential sector and 20 percent in the commercial sector.

Calculating Bundled Sales

Once the system level forecast is completed, PG&E updates its forecast for direct access and community choice aggregation departures to derive the bundled sales forecast. The assumptions are as follows:

- Direct Access: Assumes no re-opening of DA
- Community Choice Aggregation: A “bright line” regulatory forecast for 2015 and 2016, and a probabilistic forecast of CCA departure for 2017 – 2026.

CCA departures for 2015 and 2016 only include communities that pass a “bright line” test, whereas they either (1) have filed a binding notice of intent (BNI) to take responsibility for the load; (2) demonstrated a significant financial commitment to assuming responsibility for the load; or (3) are already serving customers. This test is consistent with the approach taken in the Energy Resource and Recovery Account (ERRA) proceeding. Communities meeting that test include Marin Clean Energy (including Marin County, city of Richmond, El Cerrito, San Pablo, unincorporated Napa County, and Benicia) and Sonoma Clean Power (all three phases by summer 2015).

For 2017, PG&E uses a probabilistic approach to CCA departure. PG&E assigns probabilities to the municipalities that have demonstrated significant interest and exploratory moves towards joining or forming a CCA. Those probabilities are multiplied by the load for that city to derive an “expected value” of load departure by the year 2020. Since the timing of departure is unknown, PG&E assumes a simple straight line to the expected value of CCA load in 2020. This approach is consistent with that taken in PG&E’s Bundled Procurement Plan filing in October of 2014.

Weather Adjustments

Weather adjustment of historical sales and peak data is accomplished by the inclusion of temperature variables within the regression equations. Daily temperatures are converted to degree days. Cooling degree days use 75º F as a base, while heating degree days are calculated with a base of 60º F. The residential sector includes both HDDs and CDDs in its regression equation, while the commercial equation includes only CDDs. PG&E has not found a statistically significant relationship between commercial usage and heating degree days, suggesting that commercial HVAC systems consume no more energy to heat a building than they do to provide basic ventilation. PG&E has also found that the industrial sector is temperature sensitive to CDDs, and as such, includes CDD in the large commercial and industrial regression equation.

PG&E uses CDDs and HDDs calculated on a system-wide basis. Eleven reporting stations are employed, weighted by sales. The weights are shown in the table below:

	Heating Weights	Cooling Weights
Redding	4%	5%
Fresno	15%	21%
Sacramento	19%	21%
Santa Rosa	8%	7%
Eureka	2%	1%
Oakland	13%	11%
San Jose	18%	15%
San Rafael	2%	2%
Salinas	6%	5%
Livermore	10%	10%
Paso Robles	2%	2%

Calculating Losses

Historical losses can be estimated by calculating the difference between metered sales and retail generation. PG&E has included this calculation for years 2000 through

2014 on Form 1.2. For the forecast period, PG&E uses a formulaic approach. Distribution losses are calculated as a non-linear function of the level of load; transmission losses and unaccounted for energy (UFE) are calculated as 3 percent of load, per Resource Adequacy instructions.

Calculating Hourly Loads

PG&E uses the NELF-LT model developed by Pattern Recognition Technologies, Inc. (PRT) to forecast the 1 in 2 (expected) hourly loads for 2015. The PRT model uses a neural network load forecast engine that was developed with PG&E's historical hourly loads and temperatures. Given an hourly temperature series as input, the model will generate an hourly load forecast that reflects the role of temperatures, previous day's forecast load and the calendar effects (weekday or weekend effect) on the load.

Form 1.6b contains data for various subareas, also referred to as local areas. The local areas shown on the form are defined in the publically available CAISO's "Local Capacity Technical Report," which is published annually on the following website: https://www.caiso.com/informed/Pages/StakeholderProcesses/LocalCapacityRequirementsProcess.aspx.

The subarea load data is derived from PG&E's electric transmission SCADA (Supervisory Control & Data Acquisition) system. The data is a proxy of load data in that it measures transmission line flows and generation output within the given subarea.

Reasonableness of Forecast and Accuracy

PG&E believes these forecasts which show generally flat sales, declining bundled sales, and declining peaks are reasonable given the rapid growth of distributed generation and expected impacts of energy efficiency. Electric vehicles are important, but only in the latter years of the forecast do they start to push sales up again. PG&E is already losing considerable bundled load to CCAs, and we expect this trend to continue as other municipalities actively pursue CCA programs.

PG&E's forecasting approach is typically accurate to within 1 percent in the short run (1 – 2 years) and less accurate in the long run. For example, a forecast from 2005 was approximately 6 percent too high for the year 2014. This is likely because the future effects of the recession, energy efficiency and distributed generation were not foreseen at the time.