# Notes of Pacific Gas and Electric Company
# 2013 IEPR Demand Forms for the California Energy Commission
# April 15, 2013
# Docket 13-IEP-1C

## 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 2012. Importantly, PG&E is presenting its "analytic" sales totals (adjusted totals used for modeling purposes), which may not be identical to data provided in other forms (e.g., QFERs, Annual Power Report, etc.). Total retail sales are shown on Form 1.1a by customer class. Electric vehicles are shown as a separate column item; however, usage associated with electric vehicles is also embedded in customer class sales.

For recorded data, direct access amounts are not provided by customer class; only residential and non-residential totals are available. These totals are presented in Form 1.1b, along with the bundled sales calculation for each sector.

In the forecast period 2013-2024, PG&E has included the effects of customer energy efficiency programs as described in Section 3.1A below. These targets are supplemented by the views of the Energy Efficiency Departments as reasonably expected to occur; these targets are regarded as uncommitted. PG&E has also included the impacts the California Solar Initiative as well as customer self-generation programs consistent with those developed for the 2012 Long Term Procurement Plan High Case Assumptions. For direct access (DA) and community choice aggregation (CCA), PG&E has incorporated the latest policy decisions consistent with current tariffs. Decision 10-03-022 reopening DA to new customers established a target cap and phase-in schedule, and this has been incorporated into the forecast. PG&E has also included customers who are currently being served by a CCA (at present, Marin Clean Energy is the only active CCA).

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 Form 1.1b. PG&E has no reason, at this time, to expect a material change in departing load relative to historic trends associated with municipal departing 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 the CPUC targets 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, PG&E is 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% and 0.5%, 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 2013 through 2024 are included in the forecast data.

Form 1.4 Distribution Area Coincident Peak Demand

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

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 PG&E currently does 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.

Form 1.6a Distribution Area Hourly Load

All assumptions described for Forms 1.3 and 1.4 are also applicable to the hourly loads in Form 1.6a.

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)

Two subarea breakdowns are provided in Form1.6b for PG&E. The first breakdown shows the hourly load for NP15 and ZP26, which together sum to the Total System Load provided in Form 1.6a. The second 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 in Form 1.6a, as there is load within PG&E's total system area not represented in any one local area.

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

Form 1.7 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. Electricity Forecast Input Assumptions

Form 2.1 PG&E Planning Area Economic and Demographic Inputs

Inputs are drawn from Moody's Analytics December 2012 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 simplified residential, commercial, and industrial price assumptions to effectively create "seed" rates that drive each respective equation. The rates developed for this purpose of forecasting sales are escalated by changes specified in the 2013 Annual Electric True-Up. Beyond 2013, rates are escalated by the annual change in the CPI from Moody's previously mentioned forecast, plus an additional 1%.

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. Demand Side Management (DSM) Program Impacts

### Energy Efficiency Program Costs and Impacts (Forms 3.1a, 3.1b, 3.1c, and 3.2)

Energy Efficiency ("EE") costs and energy savings impacts in Forms 3.1a, 3.1b, 3.1c, and 3.2 for the indicated years are provided in the required tables, with data source and assumption explanations included below for each form.

Energy Efficiency Calculations and Assumptions (Forms 3.1a, 3.1b, 3.1c, and 3.2)

Form 3.1A: Efficiency Program First Year Gross Impacts

2000-2009

Historical savings figures are from PG&E filed savings reports with the CPUC, as found on the CPUC's Energy Efficiency Groupware Application ("EEGA").

2010-2012

Figures for 2010-2012 are from the December 2012 EEGA monthly report; EEGA is the database the CPUC uses for IOU energy efficiency reports.

2013-2014

For 2013-2014, savings figures were taken from PG&E's compliance advice letter filed January 14, 2013 for the 2013-2014 Energy Efficiency portfolio cycle.

2015-2022

For 2015-2022, savings were from the CEC document "Managed Forecast Energy Efficiency Adjustments: Estimates of Incremental Uncommitted Energy Savings Relative to the California Energy Demand Forecast 2012-2022" (incremental uncommitted); free ridership (naturally occurring savings) was also included and came from a spreadsheet delineation of the CEC naturally occurring savings in the incremental uncommitted document; note that gas data for free ridership was not included in this analysis.

2023-2024

For 2023-2024, estimates were based on the average of the uncommitted program savings in 2021-2022.

Form 3.1B: Efficiency Program First Year Net Impacts
2000-2009

Historical savings figures are from PG&E filed savings reports with the CPUC, as found on the CPUC's EEGA.

2010-2012

Figures for 2010-2012 are from the December 2012 EEGA monthly report; EEGA is the database the CPUC uses for IOU energy efficiency reports. Final net-to-gross figures have not been calculated yet for the 2010-12 cycle, therefore a proxy of 0.7 was used for these years.

2013-2014

For 2013-2014, savings figures were taken from PG&E's compliance advice letter filed January 14, 2013 for the 2013-2014 Energy Efficiency portfolio cycle. Net figures were not included in the compliance filing, however, the PG&E estimates for net are in the 0.7 range, so 0.7 was used to estimate net savings for 2013-2014 as well.

2015-2022

For 2015-2022, savings was from the CEC document "Managed Forecast Energy Efficiency Adjustments: Estimates of Incremental Uncommitted Energy Savings Relative to the California Energy Demand Forecast 2012-2022" (incremental uncommitted); free ridership (naturally occurring savings) was excluded from these estimates.

2023-2024

For 2023-2024, estimates were based on the average of the uncommitted program savings in 2021-2022.

Form 3.2: Efficiency Program Cumulative Gross Impacts

2000-2022

In 2011, the CEC asked us to revise the title of this form from net to gross. We believe this is more meaningful, so we have done this in this form as well. However, since data from form 3.1a were utilized due to ongoing discussions around how to quantify decay, net cumulative savings could be calculated from Form 3.1b, if desired.

Form 3.3: Renewable and Distributed Generation Program Costs and Impacts

PG&E notes that there is extensive uncertainty in the distributed generation market, including programs and effects that could either enhance or inhibit customer choice. PG&E's enormously popular California Solar Initiative Program (CSI) has led to installations of PV much faster than was anticipated by the legislature when the program was established. At this time, PG&E expects the residential program to be fully committed in Q2 2013 and the nonresidential program to be fully committed in Q2 2014.[1] However, PG&E expects demand for solar to remain high, and costs for solar to continue to decrease, but there is uncertainty as to the affect from incentive budget exhaustion. Aside from incentive programs, PG&E's retail rate structure, which includes relatively high volumetric rates for residential and small commercial customers, combined with net energy metering improves the economics for PV adoption. The forecast included here assumes a continuation of current rate structure along with the revised NEM cap definition adopted by the CPUC in D.12-05-036. Consequently, the forecast here matches the high adoption case provided in the CPUC's 2012 long-term

[1] For simplicity, PG&E attributes all 2012 residential installations and all 2013 non-residential installations to CSI.

procurement plan proceeding, R.12-03-014. Peak capacity factor of 33% of nameplate was based on ITRON's 2010 CSI impact evaluation report.[2]

There are two program changes likely to affect installations of combined heat and power (CHP). In response to AB 1613, the CPUC has implemented a feed-in-tariff (FIT) for efficient CHP up to 20 MW; and the Self Generation Incentive Program (SGIP) has been expanded to include efficient CHP, after a two year hiatus. Both of these programs can be expected to increase the installation of CHP above existing market behavior. However, the market barriers to CHP installation may not easily be overcome with a FIT or incentive program and there is still uncertainty in this forecast. The current forecast is based on historic customer behavior, with higher expectations of GWh, due to expected increased operating efficiency due to the fact both the AB 1613 and SGIP program have high efficiency requirements for participation.

Finally, California's commitment to greenhouse gas emissions reductions can be expected to have an effect on customers' choices about how to meet their energy needs – including installation of renewable generation such as solar or wind, or installation of efficient CHP. Again, however, there is no existing market information about future customer behavior.

Form 3.4: Demand Response Program Costs and Impacts

Pursuant with Ordering Paragraph 5 of the Load Impact Protocols adopted in Decision 08-04-050, PG&E files load impact reports for its Demand Response Portfolio with the CPUC on April 1 of each year. The DR program impacts included in Form 3.4 for years 2013 to 2024 are based on PG&E's load impact filings on April 2, 2013[3], whereas the reported program impacts for 2010 to 2012 are consistent with the 2011 IEPR filing. The load impact filings were also used to estimate the energy component of PG&E's DR programs. Based upon those filings, PG&E has forecasted that the net annual energy change from these programs will be immaterial, largely due to (1) no program is operated more than 15 times a year, and (2) a considerable amount of the load impacts are achieved through load shifting rather than conservation.

Pursuant with D.08-04-050, as modified by CPUC Decision 10-04-006, PG&E must also file an Executive Summary that provides a ten year overview of the company's DR Portfolio on April 1st of each year. This document contains a discussion of the methodologies, assumptions, statistical models and other information relevant to how PG&E calculates its load impacts and enrollment forecasts. Along with the Load Impact Reports, the Executive Summary can be downloaded here:

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[2] See Figure 6-3, page 6-13, http://www.cpuc.ca.gov/NR/rdonlyres/E2E189A8-5494-45A1-ACF2-5F48D36A9CA7/0/CSI_2010_Impact_Eval_RevisedFinal.pdf

[3] April 1, 2013 was a CPUC holiday.

https://www.pge.com/regulation/DemandResponseOIR/Other-Docs/PGE/2013/DemandResponseOIR_Other-Doc_PGE_20130402_269621.pdf

## 4. Demand Forecast Methods and Models

PG&E currently employs regression techniques to develop both its energy and peak forecasts. The techniques combine econometric and time-series approaches, meaning that standard economic and demographic drivers are used in the equations, but are augmented by various time-series terms to further reduce residual patterns. Ten years of monthly data is used for most of the equations, except in customer classes that are not temperature sensitive, in which case quarterly data is employed.

PG&E develops its energy forecast by major customer class. This is done because the sales forecast is an input into the development of rates. The peak forecast is developed at the system retail level. The major customer classes are:

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

The above customer classes account for about 98% of PG&E's annual electric usage. The remaining customers, BART, public authority, street lighting, and interdepartmental, account for the remainder.

PG&E's general approach to constructing its regression models is to build them around factors that underlie the demand for electricity: economic/demographic, price, and weather. The specific inputs vary from model to model, and are shown in greater detail below. Moody's Analytics provides economic and demographic inputs, weather inputs are drawn from PG&E's meteorological services, the Department of Water Resources, and the Weather.com website, and price terms (historical) are compiled by PG&E's rates groups.

PG&E uses adjusted billing data by customer class as the dependent variable in its models. This data is the ultimate measure of electricity usage within PG&E's service area. Nevertheless, within this service area are embedded entities that also provide electric services to their customer bases. These entities include municipal utility districts (e.g., Palo Alto, Alameda) and irrigation districts (e.g., Modesto, Merced). Although the embedded districts, along with PG&E's retail service area comprise PG&E's transmission planning area, the electric forecast that is described above is based only on PG&E's retail customer usage. 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. With the onset of electric industry restructuring, former resale customers are now responsible for their own power procurement.

Model Components

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

## *Residential Usage*

Dependent Variable: LOG(RES_KWH/HH_PGE)
Method: Least Squares
Date: 01/05/13 Time: 15:44
Sample: 2000M01 2012M09
Included observations: 153
Convergence achieved after 12 iterations

| Variable | Coefficient | Std. Error | t-Statistic | Prob. |
|---|---|---|---|---|
| C | 12.9901 | 0.6837 | 18.9988 | 0 |
| LOG(PERSINC_PGE$B2005C/HH_PGE) | 0.2461 | 0.1681 | 1.4639 | 0.1454 |
| LOG(E1_CPI_P1/CPI_PGE) | -0.0632 | 0.0723 | -0.8732 | 0.384 |
| CDD75MPT | 0.0019 | 0.0001 | 17.1116 | 0 |
| HDD60MPT | 0.0005 | 0.0000 | 10.7523 | 0 |
| AR(1) | 0.7367 | 0.0612 | 12.0341 | 0 |
| SAR(12) | 0.8764 | 0.0413 | 21.1978 | 0 |

| | | | |
|---|---|---|---|
| R-squared | 0.9472 | Mean dependent var | 13.0868 |
| Adjusted R-squared | 0.9450 | S.D. dependent var | 0.1002 |
| S.E. of regression | 0.0235 | Akaike info criterion | -4.6182 |
| Sum squared resid | 0.0807 | Schwarz criterion | -4.4795 |
| Log likelihood | 360.2890 | Hannan-Quinn criter. | -4.5618 |
| F-statistic | 436.2059 | Durbin-Watson stat | 2.0596 |
| Prob(F-statistic) | 0.0000 | | |

## *Commercial Usage*

Dependent Variable: LOG(COM_KWH)
Method: Least Squares
Date: 03/21/13 Time: 16:46
Sample: 2000M01 2012M09
Included observations: 153
Convergence achieved after 9 iterations

| Variable | Coefficient | Std. Error | t-Statistic | Prob. |
|---|---|---|---|---|
| C | 17.3653 | 1.1438 | 15.1826 | 0.0000 |
| LOG(GMP_SVCPGE$2005C) | 0.4451 | 0.1277 | 3.4844 | 0.0007 |
| LOG(GMP_SVCPGE$2005C/ESV_PGE) | -0.6427 | 0.2252 | -2.8540 | 0.0050 |
| LOG(A10_CPI_P1/CPI_PGE) | -0.0442 | 0.0243 | -1.8174 | 0.0713 |
| CDD75MPT | 0.0007 | 0.0001 | 7.5572 | 0.0000 |
| ENERGYCRISIS | -0.0506 | 0.0099 | -5.0982 | 0.0000 |
| DUM2004_0103 | 0.0214 | 0.0105 | 2.0433 | 0.0429 |
| @SEAS(3) | -0.0209 | 0.0039 | -5.4089 | 0.0000 |
| @SEAS(5) | 0.0521 | 0.0088 | 5.9336 | 0.0000 |
| @SEAS(6) | 0.0663 | 0.0118 | 5.6277 | 0.0000 |
| @SEAS(7) | 0.0612 | 0.0151 | 4.0491 | 0.0001 |
| @SEAS(8) | 0.0675 | 0.0144 | 4.6857 | 0.0000 |
| @SEAS(9) | 0.0800 | 0.0128 | 6.2584 | 0.0000 |
| @SEAS(10) | 0.0353 | 0.0098 | 3.5885 | 0.0005 |
| @SEAS(11) | 0.0259 | 0.0048 | 5.3683 | 0.0000 |
| AR(1) | 0.5495 | 0.0744 | 7.3863 | 0.0000 |

| | | | |
|---|---|---|---|
| R-squared | 0.9533 | Mean dependent var | 21.7132 |
| Adjusted R-squared | 0.9481 | S.D. dependent var | 0.0686 |
| S.E. of regression | 0.0156 | Akaike info criterion | -5.3811 |
| Sum squared resid | 0.0335 | Schwarz criterion | -5.0642 |
| Log likelihood | 427.6559 | Hannan-Quinn criter. | -5.2524 |
| F-statistic | 186.3002 | Durbin-Watson stat | 2.2501 |
| Prob(F-statistic) | 0 | | |

## *Industrial Usage*

Dependent Variable: LOG(LARGE_KWH)
Method: Least Squares
Date: 01/05/13 Time: 16:03
Sample: 2000Q1 2012Q3
Included observations: 51
Convergence achieved after 10 iterations
MA Backcast: 1999Q4

| Variable | Coefficient | Std. Error | t-Statistic | Prob. |
|---|---|---|---|---|
| C | 17.3812 | 0.5185 | 33.5249 | 0 |
| LOG(GMP_MANUFPGE$2005C/EM_PGE) | -0.5049 | 0.0960 | -5.2615 | 0 |
| LOG(GMP_MANUFPGE$2005C) | 0.6458 | 0.1433 | 4.5079 | 0 |
| LOG(E20_CPI_P1/CPI_PGE) | -0.1114 | 0.0531 | -2.0965 | 0.042 |
| @SEAS(1) | -0.0330 | 0.0064 | -5.1412 | 0 |
| @SEAS(2) | 0.0292 | 0.0080 | 3.6701 | 0.0007 |
| @SEAS(3) | 0.1033 | 0.0064 | 16.1170 | 0 |
| MA(1) | 0.4305 | 0.1385 | 3.1084 | 0.0033 |

| | | | |
|---|---|---|---|
| R-squared | 0.9429 | Mean dependent var | 22.0557 |
| Adjusted R-squared | 0.9336 | S.D. dependent var | 0.0712 |
| S.E. of regression | 0.0183 | Akaike info criterion | -5.0156 |
| Sum squared resid | 0.0145 | Schwarz criterion | -4.7125 |
| Log likelihood | 135.8966 | Hannan-Quinn criter. | -4.8998 |
| F-statistic | 101.4856 | Durbin-Watson stat | 1.8751 |
| Prob(F-statistic) | 0 | | |

## *Agricultural Usage*

Dependent Variable: AG_KWH
Method: Least Squares
Date: 12/24/12 Time: 10:33
Sample: 2000Q1 2012Q3
Included observations: 51
Convergence achieved after 17 iterations

| Variable | Coefficient | Std. Error | t-Statistic | Prob. |
|---|---|---|---|---|
| C | 944,251,487 | 1.63E+08 | 5.7872 | 0 |
| RAIN1 | -8,264,044 | 2,217,358 | -3.7270 | 0.0006 |
| RAIN2 | -17,952,062 | 2,587,880 | -6.9370 | 0 |
| RAIN3 | -9,923,549 | 2,508,738 | -3.9556 | 0.0003 |
| @SEAS(2) | 1,164,652,957 | 1.18E+08 | 9.8780 | 0 |
| @SEAS(3) | 1,265,910,034 | 1.33E+08 | 9.5131 | 0 |
| AR(1) | 0.6673 | 0.1337 | 4.9919 | 0 |
| SAR(4) | 0.7243 | 0.1273 | 5.6884 | 0 |

| | | | |
|---|---|---|---|
| R-squared | 0.9707 | Mean dependent var | 1.16E+09 |
| Adjusted R-squared | 0.9660 | S.D. dependent var | 5.10E+08 |
| S.E. of regression | 94,121,966 | Akaike info criterion | 39.7012 |
| Sum squared resid | 3.81E+17 | Schwarz criterion | 40.0042 |
| Log likelihood | -1004.38 | Hannan-Quinn criter. | 39.8170 |
| F-statistic | 203.6925 | Durbin-Watson stat | 1.9055 |
| Prob(F-statistic) | 0 | | |

## *Peak Demand*

| | | | | |
|---|---|---|---|---|
| Dependent Variable: LOG(LINE17MW) | | | | |
| Method: Least Squares | | | | |
| Date: 01/29/13 Time: 13:53 | | | | |
| Sample: 2000M01 2012M09 | | | | |
| Included observations: 153 | | | | |
| Convergence achieved after 6 iterations | | | | |
| | | | | |
| Variable | Coefficient | Std. Error | t-Statistic | Prob. |
| | | | | |
| WINTER*HDD60 | 0.0032 | 0.0009 | 3.3628 | 0.001 |
| SHOULDER*CDD75 | 0.0432 | 0.0027 | 15.9086 | 0 |
| SUMMER*CDD75 | 0.0239 | 0.0025 | 9.4638 | 0 |
| LOG(GMP_PEAK) | 0.1481 | 0.0665 | 2.2277 | 0.0276 |
| SUMMER*LOG(HH_PGE) | 0.3111 | 0.1693 | 1.8378 | 0.0683 |
| ENERGYCRISIS | -0.0788 | 0.0141 | -5.5774 | 0 |
| JAN | 7.5878 | 0.8310 | 9.1311 | 0 |
| FEB | 7.5588 | 0.8315 | 9.0909 | 0 |
| MAR | 7.5577 | 0.8321 | 9.0824 | 0 |
| APR | 7.5285 | 0.8338 | 9.0292 | 0 |
| MAY | 7.5660 | 0.8344 | 9.0675 | 0 |
| JUN | 5.0714 | 1.3223 | 3.8353 | 0.0002 |
| JUL | 5.1018 | 1.3226 | 3.8573 | 0.0002 |
| AUG | 5.0964 | 1.3224 | 3.8540 | 0.0002 |
| SEP | 5.0707 | 1.3220 | 3.8357 | 0.0002 |
| OCT | 7.5623 | 0.8338 | 9.0702 | 0 |
| NOV | 7.5899 | 0.8315 | 9.1276 | 0 |
| DEC | 7.6230 | 0.8309 | 9.1740 | 0 |
| AR(1) | 0.2441 | 0.0864 | 2.8264 | 0.0054 |
| | | | | |
| R-squared | 0.9666 | Mean dependent var | | 9.5875 |
| Adjusted R-squared | 0.9622 | S.D. dependent var | | 0.1595 |
| S.E. of regression | 0.0310 | Akaike info criterion | | -3.9923 |
| Sum squared resid | 0.1290 | Schwarz criterion | | -3.6160 |
| Log likelihood | 324.4113 | Hannan-Quinn criter. | | -3.8394 |
| Durbin-Watson stat | 2.0598 | | | |

The above equations, run with Moody's Analytics December 2012 economic and demographic projections for PG&E's service area economy, form the basis for the energy and peak forecasts. To the extent, however, those assumptions on various public policies and regulations will differ in the future compared to those in effect during the equation estimation periods; these assumptions need to be incorporated into the forecast. These assumptions include policy decisions on energy efficiency, distributed generation, electrification, direct access, and community choice aggregation. 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. For the most part, PG&E relies on existing documents, projections, or regulatory decisions on which to base these assumptions:

- Conservation and Energy Efficiency: Energy Division Goals
- Distributed Generation & California Solar Initiative: PG&E internal analysis
- Electrification (Electric Vehicles): PG&E internal analysis
- Direct Access: Increased Limits for DA (D.10-03-022)
- Community Choice Aggregation: CCA Service Commencement

The impacts of conservation, energy efficiency, and distributed generation are significant, meeting about 75% (over 25,000 GWh) of expected growth in energy demand over the period. On peak, the aforementioned programs also meet about 75% (about 6,000 MW) of the expected growth in load.

As described above, direct access and community choice aggregation inputs are derived directly from publically available documents. For direct access, PG&E relied upon D.10-03-022, which describes the 4-year phase-in of an additional 4,000 GWh of allowed direct access. PG&E's assumptions on community choice aggregation are relegated to Marin Clean Energy, which began providing service to customers in mid-2010. MCE is now serving most customers outlined in its Implementation Plan. An additional phase, based on a solicitation of customers in the city of Richmond, has not been included in this forecast. Likewise, PG&E has not included any assumptions regarding the CCA associated with the city of San Francisco.

Weather adjustment of historical sales and peak data is accomplished automatically by the inclusion of temperature variables within the regression equations. Daily temperatures are converted to degree days (cooling and heating) to better frame behavioral response to increasing temperatures (cooling degree days) and decreasing temperatures (heating degree days). Cooling degree days use 75$^{o}$ F as a base, while heating degree days are calculated with a base of 60$^{o}$F. The residential sector includes both HDDs and CDDs in its regression equation; while the commercial equation includes only CDDs (PG&E has never been able find 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.) The industrial sector is temperature insensitive, and neither CDDs nor HDDs are included in the industrial sales equation. PG&E uses CDDs and HDDs calculated on a system-wide basis. Eleven reporting stations are employed, weighted by sales. The table below shows the reporting stations along with their respective weights for cooling and heating degree day calculations

| Station | Weight (cooling) | Weight (heating) |
|---|---|---|
| Redding | .048 | .044 |
| Fresno | .209 | .146 |
| Sacramento | .209 | .191 |
| Santa Rosa | .066 | .077 |
| Eureka | .013 | .018 |
| Oakland | .107 | .136 |

| | | |
|---|---|---|
| San Jose | .156 | .180 |
| San Rafael | .020 | .025 |
| Salinas | .052 | .064 |
| Livermore | .106 | .105 |
| Paso Robles | .015 | .016 |

Historical losses are, of course, unknown, but can be estimated by calculating the difference between metered sales and retail generation. PG&E has included this calculation for years 2000 through 2012 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% of load, per Resource Adequacy instructions.

Economic and Demographic Inputs

As mentioned above, PG&E draws its inputs from Moody's Analytics, which has developed a customized economic and demographic forecast for PG&E's service area. PG&E has employed Moody's Analytics December 2012 projections to develop its load forecast presented here. The input drivers should be thought of as expected value projections, i.e., there is an equal chance that observed values will be either above or below the forecast values. The narrative below from Moody's Analytics describes the economic and demographic outlook for PG&E's service area economy.

"Recent Performance. The PG&E service territory's recovery is strengthening, outpacing U.S. growth for more than six months. Broad-based service gains, along with a robust uptick in the Bay Area's tech industries, are leading payroll expansion. The jobless rate slipped below 10%, its lowest in almost four years. However, the unemployment rate is still well above the national rate of 7.7%, buoyed by the Central Valley's still-weak labor market. Foreclosure rates remain above the national average across the service territory but are falling. House prices in the Bay Area are showing signs of life, and residential permits are slowly edging higher, even in the hard-hit inland areas.

Tech. The tech industry will slow over the next few quarters but remain a primary source of employment and wage growth. European economic woes, along with other emerging headwinds, are forcing less profitable firms and those facing structural changes in consumer and business preferences such as semiconductor makers AMD and Intel to shed workers both globally and locally. The euro zone recession will weigh on San Jose in particular, as Europe represents 20% of exports and accounted for 3.9% of gross metro product in 2011.

The expansion of ROHM Semiconductor, however, will partially offset this drag. The tech manufacturer is expanding its engineering and R&D divisions, doubling the size of its headquarters in Santa Clara, as part of an effort to breach new markets such as mobile chips. What is more, fledgling venture-funded tech firms will benefit from the

replacement of San Francisco's local payroll tax with a gross receipts tax since they have expanding payrolls but slow revenue growth.

Fiscal woes. Government budget issues will drag on the service territory over the coming year, but bright spots are forming. Voter approval of temporary tax increases on the statewide sales tax and personal income tax rate paid by high-income residents will minimize California's budget deficit and spare K-12 and higher education from further cuts. Accounting for this, the Legislative Analyst's Office is projecting a combined budget shortfall of $1.9 billion in 2013-2014, the smallest in recent years. This will be followed by growing budget surpluses through 2017-2018, allowing policymakers to stem spending cuts and fund new investments throughout the service territory.

Still, downside risks persist. Local government budgets are fragile, especially throughout the inland areas, as the housing market and thus property taxes remain weak. If the U.S. goes over the full fiscal cliff, defense contracts in Vallejo could be affected. What is more, the U.S. would slide into a new recession; reduced consumer spending would weigh on the Bay Area's tech industry and the Central Valley's agricultural sector.

High-speed rail. Central Valley construction payrolls will be lifted in the summer of 2013 when work on the first phase of the state's high-speed rail system begins. This will provide immediate economic relief to the hard-hit inland areas that have been slow to recover from the housing crash. However, a pending lawsuit alleging that the potential environmental impact of the project was inadequately considered will be heard in the spring and could delay construction.

The PG&E service territory's economy will decelerate over the first half of 2013. However, it will gain traction toward the end of the year when consumer spending accelerates and the housing market improves. High-tech industries will remain a bright spot, but the expansion of those industries will primarily benefit the Bay Area and will not contribute significantly to the Central Valley's recovery. Longer term, the service territory will grow in line with the nation.

Sean F. Ellis
December 2012"

Efficiency Forecast Methods

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

1. Ten years of EE savings data is gathered to find the average EE impact in the committed period.
2. The average EE impact is compared to future EE savings projections in the uncommitted period.

3. If the future EE impact is projected to be greater than past EE impact, the forecast is decremented by the difference. Note the demand forecast is not increased if uncommitted incremental EE savings are forecasted to be less than the historical average.

## 5. Committed Demand-Side Program Methodology

Efficiency Program Costs and Impacts

See discussion under Form 3.1a, 3.1b, 3.1c, and 3.2.

Assumptions used to calculate net energy savings impacts, such as the effective useful lives of energy efficiency measures, net-to-gross ratios, per-unit energy savings, and incremental measure costs are derived as described in the CPUC Energy Efficiency Policy Manual. PG&E uses the Database for Energy Efficiency Resources (DEER) and developed workpapers for the per-unit energy savings assumptions and incremental measure costs.

Demand Response

See the discussion under Form 3.4 above.

## 6. Uncommitted Demand-Side Program Methodology

Energy Efficiency

See discussion under Form 3.1a, 3.1b, 3.1c, and 3.2.

Assumptions used to calculate net energy savings impacts, such as the effective useful lives of energy efficiency measures, net-to-gross ratios, per-unit energy savings, and incremental measure costs are derived as described in the CPUC Energy Efficiency Policy Manual. PG&E uses the DEER and developed work papers for the per-unit energy savings assumptions and incremental measure costs.

Demand Response

All PG&E DR programs included in this IEPR forecast are considered "committed" according to the definition in the Forms and Instructions for Electricity Demand Forecast for the 2013 Integrated Energy Policy Report: "Committed programs are defined as programs that have been implemented or for which funding has been approved" (page 5).