PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

DISTRIBUTION EXPANSION PLANNING PROCESS AND PROJECT COSTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6
DISTRIBUTION EXPANSION PLANNING PROCESS AND PROJECT COSTS

TABLE OF CONTENTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6
DISTRIBUTION EXPANSION PLANNING PROCESS AND PROJECT COSTS

A. Introduction

This chapter describes the planning process that Pacific Gas and Electric Company (PG&E) uses to develop circuit and bank load forecasts and distribution expansion plans, both of which are used to develop area distribution marginal costs.

PG&E's distribution system is defined as facilities operated at voltages less than 50 kilovolts (kV). This system is further divided into two parts: (1) the primary distribution system; and (2) the secondary distribution system. Any equipment operating at or above 4 kV is considered part of the primary system and is covered under this chapter. This chapter addresses the planning process for the primary distribution system.[1]

The purpose of the planning process is to provide sufficient substation and circuit capacity so that equipment is not overloaded and so that service-operating parameters (e.g., voltage limits and adequate reliability levels) are maintained under both normal and emergency operating conditions.

The basic distribution planning approach described in this chapter is generally similar to those described in PG&E's previous General Rate Cases (GRC) beginning with the 1993 GRC. As with those previous rate cases, the location and time-specific distribution plans resulting from PG&E's planning process continue to support a marginal cost methodology that is forward-looking, captures the timing and magnitude of planned investments, and reflects cost differences by geographic area (18 divisions).[2]

---

1 Secondary systems operate at less than 600 volts. In contrast to primary distribution, most secondary distribution investments are made for the purpose of connecting new customers to the distribution grid or as small projects to correct secondary voltage issues. Since most secondary distribution system investments come about because of customer notifications to PG&E, no formal planning process for secondary distribution investments is needed.

2 For purposes of distribution planning, Humboldt and Sonoma are evaluated as one Division. For evaluation of marginal costs in the subsequent chapters, these operating divisions are shown separately.

However, while the basic distribution planning approach has remained generally consistent over time, in 2016 PG&E revised the load forecasting process to include a Distributed Energy Resource (DER) growth scenario as a layer in the forecasting process. This change is discussed in Section C, below.

The remainder of this chapter is organized as follows:

- Section B – Selection of Distribution Study Areas
- Section C – Load Forecasting
- Section D – Capability of Facilities
- Section E – Distribution Expansion Plans and Costs
- Section F – Emergency Capacity 2020 GRC Phase I Testimony
- Section G – Non-Marginality of Distribution Operations and Maintenance (O&M) and Replacement Costs
- Section H – Distribution Capacity Planning – DER Alternative Analysis
- Section I – Results and Conclusion

The basic elements listed above are the same as those presented during Phase II of PG&E's 2017 GRC. The workpapers supporting this chapter include a copy of Electric Distribution Engineering and Planning Drawing 050864, Guide for Planning Area Distribution Facilities.

B. Selection of Distribution Study Areas

PG&E divides its distribution system into specific geographic areas or Distribution Planning Areas (DPA). Prior to 2012, PG&E had forecasted distribution expansion based on DPAs and analyzed load and capacity at the DPA level. However, since the adoption of the LoadSEER forecasting software in 2012, forecasts have been performed at a more granular level (the distribution substation transformer bank (Bank) and circuit level) so the DPA no longer had significance in PG&E's planning or forecasting process.

Ideally, a DPA has uniform load distribution, uniform load growth rate, a single primary distribution voltage, strong distribution ties among substations inside the area, and limited ties to substations outside the area. Although perfectly ideal DPAs are not encountered in practice, DPAs are defined as nearly as practicable to that ideal. Currently, there are 243 DPAs in PG&E's service territory. Although not used for planning or forecasting, DPA designation and boundaries have been retained as a way to identify the location of a group of substations and is generally used to assign work to PG&E's Distribution Planning engineering offices.

C. Load Forecasting

PG&E's current process forecasts load growth at the bank and circuit level, aggregated to the DPA level. PG&E's forecasting process and additional information about the forecasting program are described below.

1. Overview

PG&E's Distribution Engineers (Distribution Engineers) annually forecast the magnitude and location of load and DER growth projections to ensure that sufficient distribution capacity is available in time to meet demand growth in each area. Forecasting future loads and DER growth and assigning those adjustments to specific facilities allows adequate time to address capacity deficiencies to prevent overloading of facilities. While PG&E's planning process is designed to forecast and minimize equipment overloads, transformer bank, circuit, or component overloads can occur due to: (1) differences between actual growth and forecasted growth; (2) metering device inaccuracies; or (3) weather conditions that exceed PG&E's design one-in-ten weather event.

There are several steps that must be considered when completing load forecasts. Engineers must review available capacity, historical loading, load transfers, and adjustments to future forecasts[3] before forecasting future loads. PG&E uses a commercially-available load forecasting program called LoadSEER for this effort. This program consists of two separate forecasting applications: (1) LoadSEER Forecast Integration Tool (FIT) and (2) LoadSEER Geographic Information System (GIS). Each application uses different methodologies to develop a ten-year forecast.

Load impacts from existing interconnected small Distribution Generation (DG), Demand Response (DR), solar photovoltaic (PV), and Energy Efficiency (EE) measures are embedded in the annual historic observed peak loads. This historic data, which includes the impacts of existing DERs, is used to determine the level of temperature-normalized historic peak

---

3 Adjustments to future forecasts are based on known-loads and generation or firm capacity agreements.

demand in the LoadSEER geospatial forecasts. Incorporating the growth of DERs into the underlying load growth projections ensures they are considered when assessing distribution grid needs and scoping capacity projects.

Beginning with the 2017 forecasting cycle, which used the 2016 recorded peak update, PG&E disaggregated California Energy Commission (CEC) system-level DER growth forecasts to circuits. The inclusion of these forecasts serves to better model the interaction of customer load growth and DER growth on the distribution system in an era of increasing distributed electric resources.

2. Load Forecasting Tool – LoadSEER

a. Load Forecast

The LoadSEER Program is designed to allow PG&E's distribution planning engineers (Planning Engineers) to forecast ten years of future non-simultaneous load at the circuit, bank and DPA level, by using two different forecasting methodologies—LoadSEER FIT and LoadSEER GIS.

The LoadSEER FIT methodology uses a traditional regression forecast based on historical load peaks for the past 12 years and normalizes the data for both weather and economy. The historical peak loads are also weather-normalized during the regression analysis and the final forecast shows the load normalized to a one-in-two year (50th percentile) and one-in-ten year (90th percentile)[4] weather event. Each bank and associated circuit are assigned to a weather station to be used for the weather normalization.

The LoadSEER GIS methodology involves a spatial forecasting program that uses proprietary algorithms and satellite imagery to score each acre of PG&E's service territory for the likelihood of increased load. LoadSEER-GIS replicates urban development processes based on historical land use change, zoning information from government, customer rate class from utilities, and the energy model of consumption patterns. The LoadSEER GIS model also includes 20 years of historical

4 Guide for Planning Area Distribution Facilities 050864, p. 4.

aerial imagery of land use to determine the historical type of expansion that has occurred in an area and facilitate the scoring of each acre. The algorithm used by LoadSEER GIS evaluates and scores each acre based on the likelihood of increased load by customer class (i.e., domestic, commercial, industrial, or agricultural). The program then allocates the CEC's annual simultaneous distribution system peak load growth projections for each customer class to each parcel and circuit by identifying which circuit is in the closest proximity to the acre.

The LoadSEER FIT Program can take the simultaneous peak forecast allocations produced by customer class using the LoadSEER GIS methodology and convert it to a non-simultaneous customer class peak value by utilizing circuit hourly load profiles in LoadSEER FIT. This process has been completed for all circuits within PG&E's service territory for each of the next ten years.

1) Input Data

In preparation for the annual forecasting process, PG&E uses three years of customer Advance Metering Infrastructure meter data to develop and update the circuit hourly base load profiles. PG&E then gathers customer class counts, using the current year's July data point for each circuit and populates them into the program. In addition, the previous 12 months of hourly temperature data and the current year's summer peak load for each circuit and bank is imported. This data includes the actual peak time and date for meters that have Supervisory Control and Data Acquisition (SCADA) information. All specific data points are applied to the peak load information for each circuit and bank.

Other adjustments are entered into the appropriate sections of the LoadSEER Program, including all completed and planned transfers, any new customer load adjustments, and any planned projects that will change the normal- or emergency-capacity of the existing equipment.

2) Load Adjustments

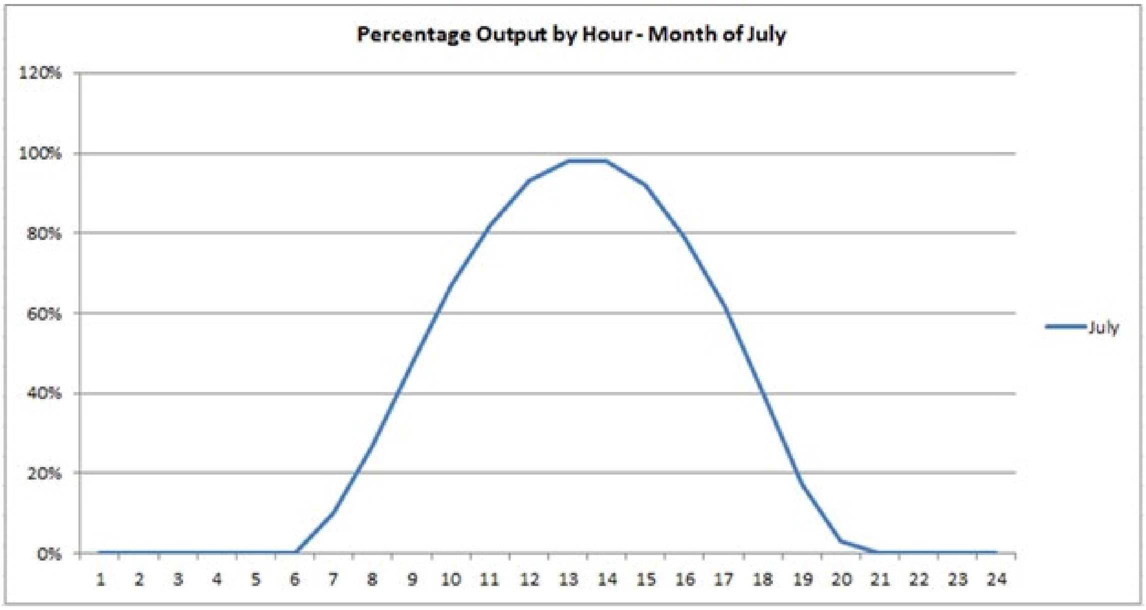
Load adjustments are added to the annual bank and circuit peaks to account for the output of the single largest DG connected to the circuit or bank during the time of the circuit or bank's peak hour. This adjustment is done to ensure that the distribution facilities are adequately sized to serve all customer load, should the largest DG system be unavailable during the time of peak loading.

The loss of the largest single DG system is considered to be the only N-1 scenario on the distribution system. The exception to this scenario is if there are multiple hydro-generation units that use the same common water source to generate; the failure of this source could result in all generators being offline. In this situation, the total output of all hydro-generation units connected to the single water source should be used to determine the amount of load adjustment added to the annual peak demand.

For photovoltaic (PV) DG systems, only the largest location with a single interconnection point capable of producing an output of 500 kilowatts or greater should be considered for an adjustment to the historical peak load. When adding a load adjustment for PV systems of this size, the hour of the circuit peaks and bank peaks[5] must be compared with the PV output at the time of facility peak to determine the approprate adjustment factor. If SCADA data is not available to determine the hour peak, then the calculated hourly load profile in LoadSEER can be used. If billing or metering data is not available for the generation output, then the nameplate rating should be used to calculate maximum system output using a typical hourly PV output chart. Figure 5-1 below shows the average hourly output for a typical PV system for July in PG&E's service territory.

5 Note that circuit peaks and bank peaks may occur at different hours.

FIGURE 5-1
PV OUTPUT – MONTH OF JULY



PV HOURLY OUTPUT CURVE

Month	Percentage Output by Hour																					
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
July	0%	0%	0%	0%	0%	10%	27%	47%	67%	82%	93%	98%	98%	92%	79%	62%	40%	17%	3%	0%	0%	0%	0%

b. Regression Models

LoadSEER FIT uses a standard multiple variable regression methodology comparing historical peak load data to historical economic factors and temperature. The coefficient of multiple determinations, commonly known as R-squared, is a statistic value that identifies how well the regression model explains the observed historical data relationship. Generally speaking, an R-squared value of 0 percent suggests that the independent variable(s) poorly support the regression forecast, whereas an R-squared value of 100 percent suggests that all of the variability in the historical data is explained by using the chosen independent variables (e.g., temperature, economic variable). LoadSEER produces an adjusted R-square statistical value to determine the accuracy of multiple variable regression analysis.

1) R-Squared

R-squared is equal to SSTO minus SSE, where the error in the response (SSTO) is the total sum, over all observations, of the squared differences of each observation from the overall mean or average of those values, and the error in the regression (SSE) is the sum of squared differences of each observation from the predicted value as expressed by the regression line. This formula is outlined as follows:

SSTO = error in the response, or the total sum of squares in the response about the mean

SSE = the error in the regression, or sum of squares in the response about the regression line.

R-squared = SSTO – SSE

Because the SSE is non-negative and cannot exceed the SSTO, R-squared varies between 0 and 1 (i.e., 0 to 100 percent).

2) Adjusted R-Squared

An adjusted R-squared value "penalizes" (decreases) as one adds more and more predictor variables, demonstrating that too many variables doesn't necessarily equate to a higher statistical regression model.

LoadSEER FIT also produces a "Model Error" score which intends to measure the degree of reliability for a particular model. By removing one of the data points for a given regression model, if there is a significant change in the Adjusted R-squared value, then the accuracy of that model when compared to the historic data is poor, and its "Model Error" score will be high, indicating it is a less-reliable forecast. Ultimately, the goal is to select the regression model with the highest adjusted R-squared and the lowest "Model Error" score.

c. Forecast Selection

As mentioned earlier, the LoadSEER FIT and LoadSEER GIS provide two types of forecasts. The two forecasts can be helpful to validate the accuracy of each. Basically, if both forecasts are trending in the same direction, this provides a higher degree of confidence in the accuracy of the forecast. If the two forecasts are trending in opposite directions, this can alert a possible error in forecasting data or significant change in future loading. Conflicting forecasts can reflect various changes in circumstance, such as downturns in economic indicators or an area reaching full buildout following a period of high growth. The LoadSEER FIT Program also has an option that allows a blend of the LoadSEER FIT and LoadSEER GIS forecasts to provide a forecast to evaluate system deficiencies.

All bank and circuit load forecasts are calculated and displayed as non-simultaneous peak load values. The LoadSEER Program automatically defaults the forecast to the LoadSEER GIS allocation of the CEC corporate forecast. This ensures that PG&E's overall distribution system forecast is closely settled to the CEC-level forecast, which has been extensively reviewed and supported by all the Investor-Owned Utilities.

Guidelines for blending the LoadSEER FIT regression forecast and LoadSEER GIS corporate forecasts are as follows:

1) If the GIS forecast for a given bank or circuit does not include future growth, but the regression forecasts have a reasonable (>.5) adjusted R-squared value and local knowledge of land or load development suggests there should be some amount of future growth, then the two forecasts can be blended, resulting in a small growth rate.
2) If the GIS forecast displays a higher growth rate for a given circuit or bank and the regression forecast has a no growth or low growth rate with a reasonable adjusted R-squared value, and local knowledge supports a lower growth rate than the corporate forecast, then the forecasts can be blended, resulting in a lower forecast.
3) In all other circumstances the forecast defaults to the CEC corporate forecast.

d. DER Forecast

LoadSEER also allocates the DER growth scenario forecast using a similar geo-spatial approach as described above for load growth allocation in Section 2.a. The starting point for each DER scenario is the adopted California Energy Commission's (CEC) California Energy Demand (CED) forecast. For each of the individual DERs,[6] a methodology has been developed to allocate projections consistent with the CED's PG&E system level projections to each of the approximately 3,200 circuits. Demographic variables used for DER allocation include various indicators such as consumption for each customer class, generation by circuit, historical PV adoption by Zip code, s-curve trending model, observed penetration levels, daily peak diversity factors, weather zones, and many other factors specific for each type of DER.

An adjustment for each type of DER, including the appropriate hourly profile, is applied at the circuit level. When an adjustment is applied, the DER forecast for PV, DR, EV, and EE are included in the final corporate forecast as an adjustment to the final load growth projection.

Currently energy storage (ES) is not disaggregated directly to the circuit level due to the limited amount of ES demographic data available. Instead, the CEC's Energy Storage discharge forecast at the time of system peak reduces the overall system level load growth forecast. This reduced system-level growth forecast is then disaggregated to circuits based on the GIS load allocation methodology.

D. Capability of Facilities

As well as creating a load forecast for each distribution transformer bank and circuit in the PG&E distribution system, LoadSEER also includes the normal and emergency capability ratings of these distribution substation assets. The substation asset capabilities are validated as part of the annual load forecasting process. Once the load forecast is complete, Distribution Engineers review the load-carrying capability of the components of the existing distribution system.

The most significant type of load growth-related electric distribution capacity expenditures are substation projects (e.g., adding new substations, new

---

6 The individual DERs are residential PV, non-residential PV, energy efficiency, electric vehicles (EV), and Demand Response (DR).

substation banks, replacing smaller substation banks with higher capacity units, and adding new circuits, etc.).

Distribution substation capability limits are generally defined by the capability of the substation's transformer banks, the transmission lines supplying the substation, or the distribution lines emanating from the substation. Each substation transformer bank and distribution circuit has a capability rating for both normal and emergency operating conditions. PG&E assigns capability ratings for distribution substation transformers using the equipment manufacturer developed nameplate rating in megavolt-ampere, while assuming a 99 percent power factor to determine the megawatt (MW) rating.

E. Distribution Expansion Plans and Costs

After the load-carrying capability for a bank or circuit has been determined (as described in Section D) the next task is to determine when forecast annual peak demands (as described in Section C) will exceed the capability of the transformer banks and circuits.

PG&E considers both the normal and emergency operating conditions of its distribution system. The following paragraphs briefly summarize the criteria used by distribution planners when preparing and reviewing distribution expansion plans.

1. Normal Criteria

Area distribution systems must include sufficient substation and circuit capability to supply forecasted peak loads without overloading any PG&E facilities or deviating from normal operating conditions.

2. Emergency Criteria

Area distribution systems are also planned so that, in the event of the loss of a single distribution facility, the remaining equipment should not be loaded beyond their emergency capabilities and should be returned to the normal capability ratings in 24 hours or less.

In this evaluation, PG&E compares the forecasted peak load of a bank or circuit to the amount of emergency capacity at adjacent circuits or substations to determine if sufficient capacity is available to serve the peak load if the bank or circuit is out of service.

Whether considering normal or emergency operating conditions, it is essential to have a working knowledge of facilities to determine what feasible alternatives can be considered to correct projected deficiencies. Before moving ahead with any major change or addition to PG&E's distribution system, Distribution Engineers perform detailed economic analyses of various feasible alternatives to identify least-cost alternatives that are operationally viable.

The distribution expansion plans used for this proceeding were developed as part of PG&E's annual five-year planning process. For each bank and circuit, Distribution Engineers provided current information on existing capacity, forecasted load growth, and the expected distribution facility installations related to load growth for each year in the five-year planning timeframe. Because construction lead time for some facilities is several years, the five-year planning horizon ensures that facilities are completed on time to meet peak demand. The information developed about expected facility installation and timing provides complete and current expansion costs for major upgrades to PG&E's distribution system. This information is included in the 2020 GRC Phase I, Exhibit (PG&E-4), Chapter 13 workpapers. This expansion plan and cost information, the load forecast data described in Section C, and division-level accounting data on small projects provide the basis for the calculation of area-specific distribution marginal costs as described in Exhibit (PG&E-2), Chapter 8, "Marginal Distribution Capacity Costs." The cost information provided is based on the information PG&E included in the 2020 GRC Phase I testimony.[7]

F. Distribution Capacity Planning DER Alternative Analysis

PG&E supports the continued and expanded integration of DERs onto PG&E's distribution grid, while maintaining grid resiliency, safety, reliability, and affordability and honoring customers' choices for access to clean energy at reasonable rates.

---

[7] See Application (A.) 18-12-009, 2020 GRC Phase I, Exhibit (PG&E-4), Ch. 13, "Electric Distribution Capacity," and associated workpapers.

The load growth forecasting process identifies capacity deficiencies and required system expansion projects needed to ensure PG&E's distribution system is adequate to serve the forecast load. Planning Engineers evaluate potential alternatives for addressing capacity issues, including DER options. As part of its normal analysis of alternatives, PG&E has also used the methodologies outlined in PG&E's Distribution Resources Plan, Distribution Investment Deferral Planning process to evaluate the cost effectiveness and feasibility of using DERs to reduce peak demand and to allow deferral of the planned capacity investment.

Based on the results of the annual load and DER forecast, grid needs identified by the forecast, and the projects identified to meet the grid needs, PG&E issued the Grid Needs Assessment report on June 1, 2018.[8] Subsequently, PG&E issued the Distribution Deferral Opportunity Report (DDOR) on September 4, 2018. The DDOR includes the list of potential Candidate Deferral Projects that was presented to the Distribution Planning Advisory Group on September 14, 2018. Projects on this list will be considered for Request for Offer (RFO) of DER deferral opportunities, subject to Commission approval. PG&E issued a subsequent DDOR in August 2019. Projects with DER RFOs will remain on the list of PG&E's planned investments until a contract that results from the RFO has been submitted and approved.[9]

G. Emergency Capacity 2020 GRC Phase I Testimony

PG&E believes it is appropriate to have adequate levels of emergency capacity in urban and suburban areas. In Phase I of its 2020 GRC (A.18-12-009), PG&E identified emergency deficiency projects in urban and suburban areas for emergency deficiencies at 10 MW or greater. Using these criteria, PG&E included four transformer emergency deficiency replacement projects in the years between 2020 and 2022.[10]

---

8 See Decision 18-02-004, Decision on Track 3 Policy Issues, Sub-Track 1 (Growth Scenarios) and Sub-track 3 (Distribution Investment and Deferral Process), issued on 2/15/18.

9 See Exhibit (PG&E-4), Ch. 13, "Electric Distribution Capacity," p. 13-9, lines 10-22 and p. 13-10, lines 1-24.

10 See Exhibit (PG&E-4), WP 13-65 to WP 13-66.

H. Non-Marginality of Distribution O&M and Replacement Costs

Generally, the costs of operating, maintaining and replacing distribution equipment, once installed, are independent of usage. Such costs associated with existing distribution equipment are considered fixed costs and excluded from marginal cost calculations.

With respect to O&M costs, Commission General Order (GO) 165[11] does not permit utilities to reduce the number or frequency of inspections as a function of declining demand. Thus, distribution maintenance costs coming under the purview of GO 165 do not vary as a function of usage.

With respect to replacement costs, for example, the life of a distribution pole is generally considered to be approximately 40 years. If a pole is 20 years old, it will require replacement in about 20 years on average. The timing and cost of replacement may be affected by environmental factors specific locations, but are largely unaffected by changes in consumer demand for electricity. Therefore, these costs are properly excluded from marginal cost calculations. The same is true for most other distribution equipment, as long as it is operated within normal operating limits.

I. Results and Conclusion

This chapter described the planning process for the primary distribution system. The purpose of the planning process is to compare load forecasts to asset capabilities in order to provide sufficient substation and circuit capacity. This ensures that equipment is not overloaded and that service-operating parameters (e.g., voltage limits and adequate reliability levels) are maintained under both normal and emergency operating conditions.

---

11 GO 165 regulates utility inspection and maintenance of certain distribution facilities.