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PACIFIC GAS AND ELECTRIC COMPANY

2017 GENERAL RATE CASE PHASE II

UPDATED AND AMENDED PREPARED TESTIMONY

EXHIBIT (PG&E-9)
VOLUME 1
MARGINAL COSTS

SUPERCEDES EXHIBITS (PG&E-1, 2, 4, 5, 6, AND 7)

PACIFIC GAS AND ELECTRIC COMPANY
2017 GENERAL RATE CASE PHASE II
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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
INTRODUCTION TO MARGINAL COST PROPOSALS

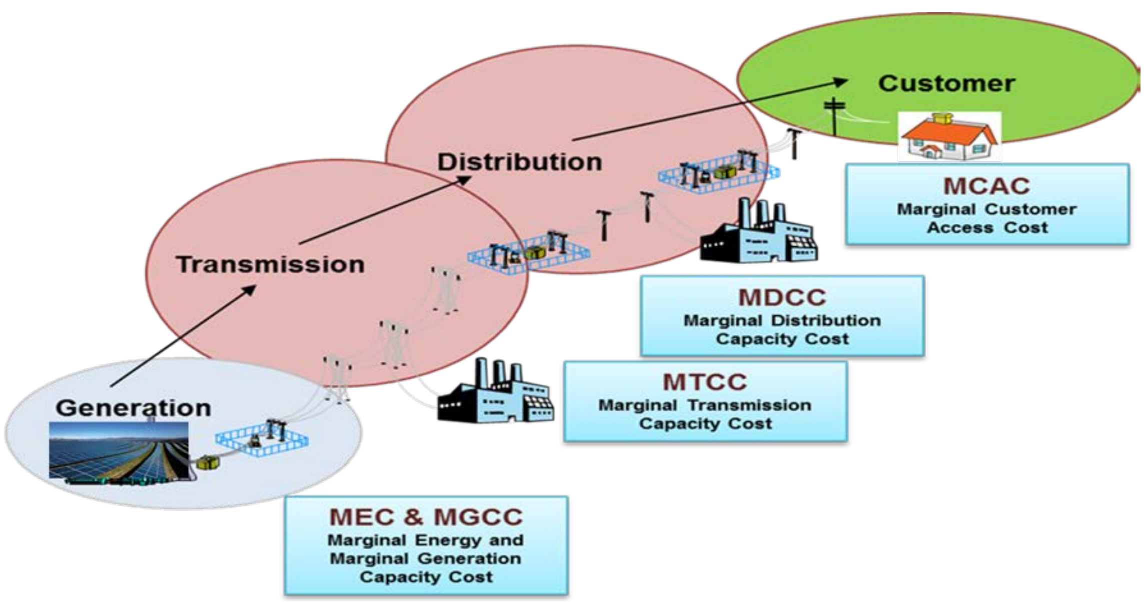
A. Introduction

This exhibit presents Pacific Gas and Electric Company's (PG&E) proposed marginal costs associated with electric generation, transmission, distribution and customer access, and describes how each is used in this General Rate Case (GRC) Phase II.

This Chapter provides an introductory overview of PG&E's marginal cost showing. Specific requests for the California Public Utilities Commission (CPUC or Commission) approval of the various methodologies and estimates obtained under those methodologies are included in the respective chapters.

To illustrate the marginal costs associated with different portions of PG&E's system, a schematic diagram of its electric generation, transmission and distribution systems is shown in the Figure 1-1 below.

FIGURE 1-1
PG&E'S ELECTRIC GENERATION, TRANSMISSION AND DISTRIBUTION SYSTEMS AND THE CORRESPONDING MARGINAL COSTS



As shown at the left of Figure 1-1, PG&E's electric system starts with generation. The two marginal cost components associated with generation are

Marginal Energy Costs (MEC) and Marginal Generation Capacity Costs (MGCC). Specifically, MEC and MGCC are associated with the energy price and the generation capacity price for an incremental unit of energy and generation capacity needed to serve customer loads. The sum of these two marginal costs produces the Marginal Generation Cost (MGC). MGC values are used to perform revenue allocation and rate design, including the design of Time-of-Use (TOU) Periods.

The next portion in the system shown in Figure 1-1 is the transmission grid. The Marginal Transmission Capacity Cost (MTCC) represents the marginal cost associated with projects deferrable in the event that there is lower incremental growth in transmission capacity requirements. MTCC is primarily needed to calculate the floor price for the rate discounts offered under Schedule E-31, PG&E's Distribution Bypass Deferral Rate, or for other analyses requiring MTCC.

The next portion of the system shown in Figure 1-1 is the distribution system. Similar to MTCC, Marginal Distribution Capacity Costs (MDCC) represents the marginal costs associated with the projects that provide incremental distribution capacity to serve load growth on the distribution system. MDCC values are used for revenue allocation and rate design.

The end-point of the electric system depicted in Figure 1-1 is the customer. Marginal Customer Access Costs (MCAC) represent the costs associated with a customer's transformer (as applicable), secondary conductor (as applicable), service conductors, meter, and revenue cycle services (for example, billing, payment processing, metering, meter maintenance, credit and collections).

For PG&E's bundled customers, PG&E supplies electric energy as well as transmits and distributes that electricity to serve their needs. The Direct Access (DA) and Community Choice Aggregation (CCA) customers obtain electric energy from third party providers. However, PG&E still transmits and distributes the electricity from their third party provider. Thus, all of PG&E's retail customers pay electric transmission and distribution (T&D) rate components, and the bundled service customers pay a generation rate component for the cost to PG&E to procure electric energy in addition to the T&D rate components. The marginal costs adopted in this proceeding will be used to determine distribution and generation rate components for PG&E's retail rates, including fixed, demand and volumetric charges as applicable for the rate schedules. Transmission rates are adopted by the Federal Energy Regulatory Commission (FERC), and are not set by the CPUC.[1]

The CPUC has a long-standing policy of using marginal costs as the basis for cost allocation and setting electric rates. The development of marginal cost methods has evolved from marginal cost framework adopted almost 35 years ago.[2] Marginal cost-based rates reflect cost causation, thereby enabling customers to make better consumption decisions. In addition to ratemaking, the Commission has used marginal costs for a variety of other applications such as evaluating the cost effectiveness of Energy Efficiency (EE) and Demand-Side Management (DSM) programs and setting price floors for discounted rates in competitive situations. Accurate marginal costs are important for all these applications.

PG&E's proposals build on the framework that has evolved under Commission regulation since 1981 and are summarized below and described in detail in subsequent chapters.

B. Organization of Exhibit

This exhibit is organized as follows:

- Chapter 1 – Introduction to Marginal Cost Proposals. Chapter 1 summarizes the economic theory of marginal costs, describes the Commission's adopted marginal cost methods, presents PG&E's marginal cost recommendations, and discusses the reasons the Commission should adopt them.
- Chapter 2 – Marginal Generation Costs. Chapter 2 describes the two components of marginal generation costs—(1) Marginal Energy Costs (MEC), expressed in cents per kilowatt-hour (kWh), and (2) Marginal Generation Capacity Costs (MGCC), expressed in dollars per kilowatt (kW)-year—and presents PG&E's proposed Marginal Generation Costs

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[1] Since transmission rates are set by the FERC, PG&E does not anticipate a ratemaking use for transmission marginal costs in this proceeding. The transmission marginal cost is an input to PG&E's contribution-to-margin model that PG&E uses to set price floors for discounted rates under Schedule E-31 (Distribution Bypass Deferral Rate).

[2] *See* D.93887, adopted by the CPUC in December 1981, discussed in Section D below.

(MGC). PG&E uses MGCs to allocate generation costs to its bundled electric service customers.

- Chapter 3 – Deferrable Transmission Capacity Projects. Chapter 3 describes the process PG&E uses to identify which transmission capacity projects, contained in PG&E's 2016 Electric Transmission Grid Expansion Plan, could be deferred if electric demand growth did not materialize as projected over the study period. These Deferrable Transmission Capacity Projects provide the basis for PG&E's marginal transmission capacity costs.
- Chapter 4 – Marginal Transmission Capacity Costs. Chapter 4 presents PG&E's estimates of demand-related marginal transmission capacity cost using the deferrable project costs identified in Chapter 3 and applying the Discounted Total Investment Method (DTIM), which is further explained in Appendix A.
- Chapter 5 – Distribution Expansion Planning Process and Projected Costs. Chapter 5 describes PG&E's planning process for developing the area-specific load forecasts and distribution expansion plans that PG&E uses to develop its area marginal costs.
- Chapter 6 – Marginal Distribution Capacity Costs. Chapter 6 presents PG&E's estimation of demand-related marginal new business primary, primary and secondary distribution capacity costs that use the area expansion plans presented in Chapter 5. PG&E continues to use the DTIM method[3] for estimating Marginal Distribution Capacity Costs (MDCC). Because area expansion plan costs are driven by changes in demand, these changes in demand represent marginal distribution system costs (excluding customer access-related costs).
- Chapter 7 – Marginal Customer Access Costs. Chapter 7 describes PG&E's methodology for calculating Marginal Customer Access Costs (MCAC) and presents PG&E's results. MCAC costs have two major components: (1) Transformer, Service and Meter (TSM)[4]; and (2) Revenue Cycle Services (RCS) costs. In this GRC filing, PG&E proposes to use Rental Method to estimate TSM costs, which is a change from its use of New

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[3] DTIM method was first proposed in 1999 by PG&E, and has been used in all GRC filings since then, and is proposed in this GRC filing.

[4] More properly, Transformer, Secondary (as applicable), Service and Meter.

Customer Only (NCO) methodology used in prior GRC Phase II filings. RCS methodology and results are discussed in a separate chapter, Chapter 8.

- Chapter 8 – Marginal Revenue Cycle Services Costs. Chapter 8 describes PG&E's methodology for calculating Revenue Cycle Services (RCS) costs. RCS costs data and methodology is being presented in a separate chapter because PG&E has made significant improvements in RCS data and methodology, compared with PG&E's showings in prior GRC Phase II filings. It is an activity based methodology whereby costs are allocated by the level of activity to various customers classes. For example, the total cost of printing bills is allocated to the customer classes by the number of printed bills.
- Chapter 9 – Generation Peak Cost Allocation Factor Analysis. Chapter 9 describes PG&E's methodology for calculating generation Peak Cost Allocation Factor (PCAF), which is used in distribution revenue allocation across PG&E's electric customer classes.
- Chapter 10 – Distribution Peak Cost Allocation Factor Analysis. Chapter 10 describes PG&E's methodology for calculating distribution PCAF, which is used to allocate distribution revenues across PG&E's electric customer classes.
- Chapter 11 – Final Line Transformer Load Analysis. Chapter 11 describes PG&E's methodology for calculating non-coincident loads. Specifically, PG&E calculates the non-coincident peak demand at the Final Line Transformer (FTL) level, which is also used to allocate distribution revenues across PG&E's electric customer classes.
- Chapter 12 – Optimal Non-Residential Time-of-Use Period Analysis. Chapter 12 describes PG&E's methodology for determining optimal Time-of-Use (TOU) periods for summer and winter seasons, and discusses PG&E's resulting recommendations for new TOU periods.[5] TOU periods for residential rate design have been kept the same as the TOU periods approved by the Commission as a settlement for the 2015 RDW filing.

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[5] PG&E's residential TOU Periods have already been updated by the CPUC in PG&E's 2015 Rate Design Window (RDW) proceeding (D.15-11-013), which adopted a settlement that established a multi-year proposal for residential TOU Periods.

- Chapter 13 – Marginal Costs Loaders and Financial Factors. Chapter 13 presents PG&E's methodologies for T&D marginal cost loaders and financial factors necessary for marginal cost estimates.

In addition to the above chapters, this exhibit includes the following appendices:

Appendix A, "Mathematical Formulation of the Discounted Total Investment Method and Alternative Methods to Compute Marginal Distribution Capacity Cost" of this exhibit, presents the mathematical formulation of PG&E's proposed DTIM and alternative methods for estimating MDCCs.

Appendix B, "Schedule E-CREDIT Update" of this exhibit, presents PG&E's proposed credits for Electric Schedule E-CREDIT applicable to DA and CCA providers.

Appendix C, "DA and CCA Service Fees" of this exhibit, presents PG&E's proposed service fees for the DA and CCA.

Appendix D, "Marginal Cost Workshop Report", describes the materials presented and comments received from workshops held by PG&E, in compliance with D.15-08-005 for all interested parties.

Appendix E, "Distribution Standby Load Diversity Study", describes the study performed by PG&E on the distribution load diversity of the standby customers required by D.15-08-005.

Appendix F, "Joint Investor-Owned Utility Fixed Charge Methodology" of this exhibit, presents the methodology PG&E proposes for the calculation of any residential fixed costs the CPUC might adopt in the future, and discusses the benefits of incorporating a fixed monthly charge for residential customers as is done with all other customer classes.

The remainder of this chapter is organized as follows:

- Section C – The Economic Theory of Marginal Costs
- Section D – The Commission's Adopted Marginal Cost Methods
- Section E – PG&E's Proposed Marginal Cost Approach
- Section F – Conclusion

C. The Economic Theory of Marginal Costs

As commonly defined by economists, the marginal cost of a particular service measures the *change in the total cost of providing that service caused by a small quantity change in output*. Long-established economic theory holds that an additional unit of consumption should occur if, and only if, the value of that consumption to the customer exceeds the marginal cost. The importance of marginal costs in economic theory is that, as a general principle, economic efficiency is maximized when prices are set at marginal cost. Thus, an important principle in developing marginal costs is that they should be forward-looking and causally linked to a change in demand.

Given the regulated utility's obligation to serve, an electric utility's marginal cost is the *change in total cost to provide the designated service resulting from a small change in demand*. The demand for electric generation is measured in kWs for capacity or kWhs for energy; the demand for T&D is measured in kW; and the demand for customer access is measured in numbers of customers (new and existing).

In most modern utility systems, including PG&E's, the additional cost incurred to serve another small increment of demand varies substantially, and often depends on the specific location and particular time that this demand is consumed. Broad aggregations across time intervals and geographic areas sacrifice important costing detail. The consequence is less accurate results for current and future utility marginal cost applications. The marginal costs and methodological enhancements proposed in this exhibit are designed to minimize these types of estimation inaccuracies.

While an accurate estimation of strictly defined marginal costs is difficult to develop, the principle that marginal cost estimates should be forward-looking, especially for load growth-related costs should be consistently applied. There should be a causal link between a change in demand and any given expenditure that goes into the calculation of marginal cost. To strengthen this link, it follows that these forward-looking costs should be developed based on future resource and investment plans, to the extent practicable. In addition, the length of time over which these costs are estimated should be sufficiently long to encompass the planning process for adding capital investments to address changes in demand.

Marginal costs are different from both embedded costs and replacement costs. Embedded costs are commonly used by electric utilities like PG&E to derive the revenue requirement for the recovery of past investment costs (including a return on that investment). However, embedded costs are historical, backward-looking costs that are unaffected by changes in current or future consumption, and, therefore, they offer little guidance for setting efficient prices or determining least-cost investment plans. Replacement costs, while forward-looking, may or may not be valid components of the marginal cost depending on whether the timing and magnitude of replacement costs are affected by changes in demand.

D. The Commission's Adopted Marginal Cost Methods

The Commission's use of marginal costs for the purpose of electric revenue allocation and rate design dates back to 1981 when the CPUC transitioned from the use of embedded costs to a marginal-cost-based approach:

> We have chosen marginal costs as our foundation for [electric cost] allocation and rate design. *We have used marginal costs to promote economic efficiency* and to provide the greatest good for the greatest number. (D.93887, 7 CPUC 2d 349, 492 (1981), emphasis added.)

The CPUC later reiterated that:

> The theory behind adoption of marginal costs was that they would provide a better price signal to customers of the impact of their consumption decisions on the utility cost of providing service on a prospective basis and hopefully would induce them to be more efficient. (D.92-12-057, 47 CPUC 2d 143, 276 (1992).)

Throughout the approximately 35-year history of Commission-adopted marginal cost-based ratemaking, there has been a continual evolution in marginal cost methodologies, with a general trend toward greater detail and greater accuracy. Over time, Commission-adopted marginal cost methodologies have become more sensitive to the underlying factors, such as the timing and location of growth-related investments, which affect the cost of service, resulting in more accurate marginal cost estimates. Significant developments regarding marginal cost methodology during the mid- to late-1990s are as follows.

In Decision (D.) 92-12-057, deciding PG&E's 1993 GRC Phase II proceeding, the Commission adopted, with limited modifications, certain PG&E proposals that the CPUC hailed as "advancements," that make a "thorough alteration to our current methodology of marginal costs." (*Id.,* mimeo, at p. 276.) The CPUC called this a "trial run" for PG&E electric proceedings only, with the goal being "to continue to improve our methodology of sending the most accurate marginal cost price signals to PG&E's customers." (*Id*.) The CPUC concluded:

> [W]e agree with PG&E's policy principle that marginal cost components should be based on the design and operation of PG&E's system, *accurately* signal the cost of providing electrical service, be *forward-looking*, *capture the timing and magnitude of future investments*, *reflect geographic differences* where significant, reflect the value that PG&E's customers place on electric service, only include those costs actually incurred by PG&E for revenue allocation purposes, and, finally, provide consistent signals *in the evaluation of supply and demand resources for planning purposes. Our goal is to more fairly and equitably allocate responsibility to the several customer classes for recovery of PG&E's. . . revenue requirement*. . . . We are committed that marginal cost pricing, when refined sufficiently, will send price signals to consumers which will guide resource planning for the future. In fact, a major attraction of PG&E's recommended changes is the *forward-looking* aspect of its proposals. (*Id.,* at 276-277, emphasis added.)

Included among the 1993 GRC's advancements was, for the first time, estimating marginal costs based on PG&E's 13 operating divisions.[6] The CPUC agreed that "this substantially increases accuracy, thus sending price signals which better reflect the differing costs customers cause PG&E to incur, and furthermore provides the area-specific data necessary for future targeting of customer energy efficiency (CEE) programs." (*Id.,* at p. 303; Finding of Fact (FOF) 158.) The CPUC went a step further and directed PG&E:

> . . . to refine its original proposal of breaking down its area study to the TPA [Transmission Planning Area] and DPA [Distribution Planning Area] levels in its next General Rate Case because we endorse the concept that *more disaggregated data* yields better and more equitable marginal costs for different customer classes. (*Id.,* at 303, emphasis added; FOF 159.)

In addition, the CPUC adopted PG&E's proposed Present Worth Method (PWM) for marginal cost estimation, because "it is the only method which estimates the opportunity cost of deferring transmission and distribution investments due to a change in load growth, taking into account both the timing and magnitude of such changes." (*Id*., FOF 160, p. 303.)[7] Also in the

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6 As a compromise between accuracy and manageability of data, in PG&E's 1993 GRC, the Commission adopted location-specific MDCCs based on PG&E's then-existing 13 operating divisions. Division-level MDCC values are determined by aggregating the investments and loads of the Distribution Planning Areas that make up the operating divisions.

7 At the time the CPUC issued its 1993 PG&E GRC Phase II decision, it recognized solely the PWM as a means for incorporating opportunity costs or time value of money with regard to the timing and size of T&D investments. Subsequently, the Commission has also recognized the DTIM as another method that, likewise, recognizes the time value of money with respect to the timing and magnitude of investments. (*See* D.92-12-058)

1993 GRC, the CPUC for the first time adopted the NCO method for determining marginal customer access costs.

In PG&E's 1996 GRC, PG&E proposed marginal cost methodologies that continued and extended the advances[8] the Commission adopted in its 1993 GRC. In PG&E's 1996 GRC (D.97-03-017, 71 CPUC 2d 212 (1997)), the Commission adopted PG&E's proposed location-specific marginal costs and NCO methodology, with modifications, but this time the CPUC rejected PG&E's PWM based on location-specific T&D costs,[9] ordering PG&E to return to the system-wide regression approach in use prior to 1993, but using location-specific costs aggregated to the system level. In ordering a return to the earlier methodology, the Commission stated:

> . . . if PG&E is to get reliable [transmission and distribution (T&D)] marginal cost estimates, it must improve the breadth, accuracy, and texture of its [T&D planning] data. (*Id.*, at p. 217.)

In contrast, in Southern California Edison Company's (SCE) 1995 GRC Phase II decision (D.96-04-050), the Commission found that SCE *should* compute T&D marginal costs by planning area consistent with the methodology adopted for PG&E in D.92-12-057.[10] PG&E has since addressed these Commission concerns about its distribution planning process, as discussed below.[11]

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8 The Commission explicitly characterized PG&E's marginal cost proposals in A.91-11-036 as "advancements." (D.92-12-057, 47 CPUC 2d at p. 236.)

9 As the 1996 GRC was being litigated, the Commission was also involved in the early stages of electric industry restructuring, with Assembly Bill 1890 being signed in September 1996, during the pendency of that GRC proceeding. PG&E's rates had also been frozen for several years. Rather than suspend the proceeding, the Commission chose to adopt new marginal costs ". . . for the limited purposes of payments to qualifying facilities. . . , evaluation of demand-side management (DSM) cost effectiveness, and price floors for discounted special contracts." (D.97-03-017, 71 CPUC 2d 212, 217 (1997).) The Commission left the door open to further reconsideration once PG&E addressed and resolved the CPUC's planning process concerns.

10 *See* D.96-04-050, 65 CPUC 2d 362, 400-402 (1996).

11 PG&E's testimony submitted in its 1999 GRC Phase II proceeding (A.99-03-014, Exhibit (PG&E-2), Chapter 3B) and in its 2003 GRC Phase II proceeding (A.04-06-024, Exhibit (PG&E-2), Appendix C) addressed the issues the CPUC raised in D.97-03-017. (See also Chapter 5, of this exhibit, for a description of PG&E's distribution expansion planning process.)

For PG&E's 1999 GRC Phase II, PG&E continued to maintain that location-specific[12] marginal distribution costs are very important to a number of marginal cost applications, specifically including the two applications mentioned in D.97-03-017 (DSM cost-effectiveness evaluation and price floors for flexible pricing schedules). Therefore, in A.99-03-014, PG&E submitted a "Report of Findings Relating to Commission Directive from D.97-03-017 (Report of Findings)" in which it detailed the improvements made to PG&E's distribution planning process in response to the 1996 GRC decision. In the belief that its improved distribution planning process satisfied the Commission's concerns, PG&E again proposed distribution marginal cost methodology with similar location-specific, timing-sensitive characteristics as the methodologies adopted in D.92-12-057. Before hearings could be held in the 1999 GRC, however, that proceeding was suspended in December 2000 due to the California Energy Crisis.[13]

Although PG&E fully addressed the Commission's 1996 GRC distribution planning concerns, those prior concerns were not expressly discussed in the decision in PG&E's 2003, 2007, 2011 and 2014 GRC Phase II proceedings, which were all settled. Because no parties raised issues in any of the proceedings after PG&E improved its distribution planning process, PG&E believes those issues have been effectively resolved.

Regarding the estimation of marginal customer access costs, the RCS decision (D.98-09-070) required PG&E to develop a detailed study of the costs it can avoid when others perform RCS activities on behalf of PG&E distribution customers. The RCS models developed for these studies were updated in preparation for the 2003, 2007, 2011 and 2014 GRC Phase II marginal cost exhibits, and were used to estimate marginal costs for certain customer services such as meter reading and billing. In this filing, PG&E has submitted and

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12 That is, specific to either PG&E's then current 18 operating divisions or PG&E's 240-plus Distribution Planning Areas (DPA). For the purposes of revenue allocation and rate design, PG&E proposes division-level marginal distribution capacity costs as adopted in D.92-12-057. The more detailed DPA-specific marginal distribution capacity costs developed in PG&E's workpapers are not used directly in PG&E's revenue allocation but may be useful for local integrated resource planning applications as well as flexible pricing schedules and price floor calculations for Schedule E-31.

13 The Commission subsequently dismissed A.99-03-014 in D.03-01-012.

significantly improved RCS cost estimation methodology that takes advantage of detailed cost and activity data available now, but were not available earlier (*See* Chapter 8).

E. PG&E's Proposed Marginal Cost Approach

PG&E's proposed marginal cost approach is based on the economic theory of marginal cost and the Commission's adopted methods, described above, with refinements. PG&E assessed the usefulness of marginal cost results in their relevant applications and introduced refinements to marginal cost approaches mostly based on improved data availability.

By way of overview, the starting point for calculating marginal costs is to identify cost drivers, that is, those fundamental aspects of customer electricity requirements that directly cause PG&E to incur costs. The next step is to calculate marginal costs for small changes in each cost driver by dividing the change in total cost by the change in the cost driver. The final step is to attribute these marginal costs to measurable aspects of customer requirements such as energy consumption, peak demand, and customer type. This allows the rate components most associated with these measurable customer requirements, specifically energy charges, demand charges, and monthly basic service fees (also known as customer charges) to be set based on the corresponding marginal cost components.

PG&E's marginal costs are based upon three cost drivers: (1) electricity usage; (2) demand; and (3) number of customers:

First, the cost of procuring electricity to meet changes in customer electricity usage varies hourly. PG&E and other load-serving entities are required to procure dependable generation resources with sufficient capacity to meet 115 percent of forecast demand. Marginal generation costs (energy and capacity) are associated with the electricity usage cost driver and are aggregated in TOU periods which group together hours with similar loads and costs.

Second, PG&E's electricity delivery system consists of a network of high-voltage (transmission) and low-voltage (distribution) facilities which connect generation resources to customer facilities. The delivery system is designed and constructed to meet the expected peak demand placed on it, so demand (capacity) is the associated cost driver. Demand is a localized cost driver, since portions of PG&E’s delivery system peak at different times depending on the area and the mix of customers by area.

Finally, the number of customers is a cost driver, reflecting the marginal costs of customer access to the distribution system and various customer services. Since the marginal costs of customer access and customer services vary by type of customer, these marginal costs are disaggregated by customer class. PG&E’s marginal customer access costs are calculated based on PG&E’s proposed return to the RM; however, PG&E also calculates these costs based on the last-adopted NCO method.

Accordingly, in this exhibit, marginal costs are estimated in three general areas:

1) Generation-related demand and energy requirements (marginal generation capacity and energy costs)
2) T&D demand requirements (marginal T&D capacity costs)
3) Incremental changes in the number of PG&E customer connections and variable operations and maintenance requirements (marginal customer access costs). This exhibit presents marginal costs for the components of PG&E’s electric system as shown in Table 1-1 provided at the end of this chapter.

The main ratemaking applications of marginal costs are revenue allocation and rate design. Other uses include EE and DSM resource planning cost-effectiveness evaluations and economic development flexible pricing floor prices.[14] Accurately estimated marginal costs are essential to efficient allocation of resources in that customers respond by choosing the correct level of consumption. In electricity ratemaking, marginal cost-based rates send price

[14] Accurately estimated, location-specific marginal costs are essential inputs to the price floors for flexible pricing options such as Schedule E-31.

signals to customers about the cost of their decisions to consume additional units.[15]

The following sections of this Chapter summarize PG&E's proposed marginal cost methodologies as they apply to each of the major electric utility functions.

1. Marginal Generation Costs

As described above, California electric utilities have traditionally filed marginal generation costs consisting of separate components for energy and capacity. In addition, Commission-adopted methodology required the use of a rolling 6-year average for ratemaking, reflecting a balance between short- and long-term price signals in rates.

Accordingly, PG&E has developed separate MECs and MGCCs as described in Chapter 2, "Marginal Generation Costs," of this exhibit. For capacity costs, the Commission has shown a preference for a longer-term perspective, such as the 6-year planning horizon it previously adopted for computing MGCC in Phase II of PG&E's and SCE's GRCs (D.89-12-057 and D.96-04-050), to adequately signal the cost impacts of consumption decisions. In this proceeding, PG&E is proposing to continue to use this same 6-year planning horizon (i.e., 2017-2022) for its MGCCs, while using a single year in the middle of that period (2020) for its MECs.

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15 As stated by Alfred E. Kahn, in his seminal work on public utility economics: "The central policy prescription of microeconomics is the equation of price and marginal cost. If economic theory is to have any relevance to public utility pricing, that is the point at which the inquiry must begin." The Economics of Regulation: Principles and Institutions, Volume I, 1970, John Wiley & Sons, Inc., New York, p. 65. Kahn explains: "If consumers are to make the choices that will yield them the greatest possible satisfaction from society's limited aggregate productive capacity, the prices that they pay for various goods and services available to them must accurately reflect their respective opportunity costs; only then will buyers be judging, in deciding what to buy and what not, whether the satisfaction they get from the purchase of any particular product is worth the sacrifice of other goods and services that its production entails." *Ibid.*, p. 66. Further, "[I]f consumers are to decide intelligently whether to take somewhat more or somewhat less of any particular item, the price they have to pay for it. . . must reflect the cost of supplying somewhat more or somewhat less—in short, marginal opportunity cost." (*Id.*, p. 66.)

The marginal generation costs[16] presented in Chapter 2, "Marginal Generation Costs," of this exhibit, are estimates of the changes in PG&E's electric procurement costs that would be caused by small changes in customers' energy usage and peak demand. PG&E believes that using a separate MEC and a separate MGCC is the most efficient approach for allocating its generation costs and providing the appropriate price signals to customers. PG&E is relying on public data sources for its inputs and PG&E uses a model that can be shared publicly with all parties, providing greater transparency for its MEC and MGCC proposals. This revised approach is discussed in further detail in Chapter 2, "Marginal Generation Costs," of this exhibit.

2. Marginal Transmission Capacity Costs

The marginal transmission capacity costs proposed here are primarily used for non-ratemaking purposes.[17] MTCCs include only those planned investments that can be avoided or deferred if load growth fails to materialize as expected.

PG&E is proposing the DTIM to estimate MTCC. As described in Chapter 4, "Marginal Transmission Capacity Costs," of this exhibit, PG&E's proposed MTCC is computed using the DTIM to reflect better the lumpiness of investments and the time value of money. In 1992, the Commission adopted the Total Investment Method (TIM) for gas transmission and the PWM for electric transmission.[18] The TIM simply computes an annualized average investment per unit of demand; it is inaccurate when investments

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16 The marginal generation costs proposed in this testimony are not applicable for determining Qualifying Facility (QF) Short-Run Avoided Costs (SRAC) or as-delivered capacity prices. The Qualifying Facility/Combined Heat and Power Program Settlement Agreement (Settlement Agreement) approved in D.10-12-035 includes a calculation of SRAC which apply to QF contracts entered into pursuant to the Public Utilities Regulatory Policy Act and the pro forma contracts adopted by the Settlement Agreement. As-delivered capacity prices for these contracts have also been adopted by the Commission. (*See also*, D.07-09-040.) Thus, the marginal generation costs recommended in this testimony are not applicable for determining SRAC or as-delivered capacity prices for QFs or any other facility governed by the Settlement Agreement.

17 Transmission rates, which are regulated by FERC, are determined on an embedded cost basis.

18 See D.92-12-058 adopted gas T&D marginal costs, and D.92-12-057 adopted electric marginal costs.

are "lumpy" (i.e., when costs are spread unevenly over time with large year-to-year variations in investment sizes)[19] because it fails to weight near-term investments more heavily than those occurring further out in time. Not including the time value of money is a deficiency of the TIM.

The DTIM proposed here for MTCC (and MDCC) corrects for the defect in the TIM of not including time value of money; the DTIM is simply the discounted version of the TIM that takes into account the time value of money.

While both the DTIM and the PWM incorporate the time value of money to account for the timing and size of investments—a key methodology attribute when costs are lumpy—PG&E proposes using the DTIM, because it incorporates the time value for the capital additions *and* capacity load, and thus this method alone recognizes that load capacity also has value.

3. Marginal Distribution Capacity Costs

Consistent with the Commission's practice since the advent of marginal cost-based ratemaking in 1981, PG&E's proposed MDCC are based on load growth-related distribution investments only. Investments that are unaffected by changes in demand, such as replacement costs and access costs specifically incurred to connect new customers, are excluded from the MDCC calculation.

PG&E's service territory has a very diverse geography and customer density. PG&E has observed a wide variation in the marginal cost of distribution capacity among the more than 240 Distribution Planning Areas (DPA) that comprise its electric system, which have been aggregated into 19 operating divisions as PG&E has done since its 1993 GRC Phase II. Therefore, PG&E's proposed MDCCs utilize a location-specific, timing-sensitive marginal cost methodology, as it has in every GRC Phase II filing since 1993.

PG&E's MDCCs consist of four components: (1) primary distribution costs for large projects greater than 1 million dollars; (2) primary distribution

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[19] For example, major new high-voltage electric transmission facilities are not built every year, and the costs for such a project will be incurred primarily in a few early years, with little or no costs in subsequent years.

costs for projects less than 1 million dollars; (3) new business primary costs; and (4) secondary costs.

PG&E proposes to use the same DTIM to calculate MDCCs of large projects as it uses to estimate MTCC because of the lumpy nature of these investments.[20] DTIM-calculated MDCCs vary by area to reflect the fact that investments during the planning horizon are needed at different times and in different sizes for different areas depending on the installed capacity and load growth unique to each area. The DTIM conforms to the Commission's guidance in D.92-12-057 and Commission-adopted marginal cost principles, and is well suited for computing area-specific marginal costs. Because PG&E now forecasts five years of load growth-related capacity investments for smaller primary, new business primary, and secondary projects, PG&E is proposing fully forward-looking marginal distribution capacity costs for these components of MDCC using DTIM in place of PG&E's prior methodology that used three years of recorded and two years of forecast data for these MDCC components. PG&E's estimates of MDCC costs are discussed in detail in Chapter 6, "Marginal Distribution Capacity Costs."

4. Marginal Customer Access Costs

In this filing, PG&E proposes MCAC estimates based on the Rental Method instead of the NCO method, which has been used by PG&E in earlier filings and was first adoption in the 1993 GRC (D.92-12-057). The Rental Method applies to the connection equipment capital costs, including transformers, as applicable, secondary, as applicable, services and meters.

PG&E has updated its RCS models in this GRC to estimate the customer-class specific marginal ongoing costs for revenue cycle services. PG&E has submitted RCS estimates based on improvements in the data and methodology, reflecting the most appropriate cost drivers that improve the estimates greatly. A separate chapter has been included in this filing to describe the RCS data, methodology and results.

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20 While distribution investments are generally less lumpy than transmission investments, geographic disaggregation increases the effect of lumpiness.

F. Importance and Relevance of Marginal Cost Applications

Accurately estimated marginal costs are essential to efficient electricity pricing because they indicate to a potential consumer the cost of the customer's decision to consume an additional unit. Chief among the ratemaking applications of marginal costs are revenue allocation, rate design and flexible pricing to deter uneconomic bypass. When based on marginal cost, rates provide appropriate incentives upon which customers can make investment decisions. Pricing that is not based on marginal cost can encourage customers to make consumption and investment decisions that are not efficient or sustainable over time.

1. Marginal Cost-Based Ratemaking

Prices set at marginal costs result in efficient resource allocation because presumably consumers respond by choosing the correct level of consumption.[21] In a regulated environment, marginal costs are used to promote economic efficiency by simulating the pricing structure—and the resulting resource allocations—of a competitive market. However, regulatory revenue requirements generally do not equal the revenues that would result from pricing output at marginal cost. To overcome the revenue shortfall, the Commission has adopted a scaler applicable to the marginal cost revenues as necessary to meet revenue requirements relying on the Equal Percentage of Marginal Costs method (EPMC).

2. Competitive Pricing to Respond to Uneconomic Bypass[22] Situations

Location-specific distribution costs, along with customer-specific loads, set the benchmark to gauge the benefit of a utility's customer retention and load attraction efforts. For instance, if the flexible price required to persuade a customer not to bypass PG&E's electric distribution system exceeds the marginal cost of serving the customer, the remaining customers are made

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21 That is, they would increase consumption until the point where the marginal benefit of consuming an additional unit just equals (but does not exceed) the marginal cost.

22 In D.92-11-052, the Commission defined uneconomic bypass as follows: "Bypass is uneconomic when a customer leaves the utility system even though its cost to bypass is more than the marginal cost of utility service. In that situation, the utility could still meet the bypass rate and obtain a positive contribution to its fixed costs, which helps keep other rates down."

better off by PG&E's customer retention effort. Similarly, if new loads can be attracted to an area at rates in excess of the area-specific marginal cost, they improve PG&E's asset utilization and help defray the rates paid by other customers.[23]

G. Conclusion

Economic theory holds that economic efficiency is maximized when prices are set at accurate marginal costs. For over three decades, the CPUC has endorsed this principle as a basis for electric revenue allocation and rate design among other applications.

PG&E's marginal cost proposals in this proceeding are consistent with sound marginal costing principles. Specifically, PG&E's proposals:

1) Are forward-looking;
2) Reflect cost-causation;
3) Are based on PG&E-specific investments;
4) Signal the timing and magnitude of future investments; and
5) Reflect least-cost planning.

The Commission has found that these attributes are important indicators of the suitability of marginal costs, to provide an efficient, equitable, and practical means of allocating revenue and designing rates, among other applications. In addition, the data and methods described in the following chapters of this exhibit support the use of PG&E's marginal cost estimates in the ratemaking functions outlined in the revenue allocation and rate design exhibit, among other applications described above.

The methods PG&E has proposed here either comport with methods previously adopted by the Commission, or are based on refinements to improve upon such methods, including improvements based on significant improvements of the data. In particular, PG&E is using the DTIM method which better captures the timing and magnitude of future investments. PG&E has also redesigned its RCS model to make it more accurate, and has rebuilt the Financial Factors model (often referred to as the Real Economic Carrying Charge (RECC) model) to consolidate and simplify the data flow and calculations. A few improvements

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23 PG&E currently has the ability to offer contracts with discounted rates for purposes of load attraction or retention under tariff Schedules E-31 and/or EDR.

have also been made to other marginal cost models, such as MDCC and MCAC, including PG&E's proposal for adopting Rental Method to estimate MCAC. These methodological improvements are discussed in the respective chapters.

For the reasons stated herein, and in the succeeding chapters in this Exhibit, the Commission should adopt PG&E's proposed marginal cost results.

TABLE 1-1
OVERVIEW OF PROPOSED MARGINAL GENERATION COSTS
DATA SOURCE, UNITS AND CALCULATION METHODOLOGY

Line No.	Function		PG&E's Methodology Submitted in the 2014 GRC Phase II	Proposed Methodology	Chapter
1	Marginal Energy Cost	*Data Source*	Applying historical market heat rates to the public market price forecast for gas and greenhouse gases (GHG). Historical market heat rates are based on the historical hourly prices in the California Independent System Operator (CAISO) Day-Ahead Market.	*Forecasting* market heat rates based on a model that is *calibrated* to historical market heat rates, using a public market price forecast for gas and GHG. Historical market heat rates are based on the historical hourly prices in the CAISO Market.	2
2		*Demand Measure*	KWh by TOU period	KWh by TOU period	
3		*Units*	¢ per KWh	¢ per KWh	
4	Marginal Generation Capacity Cost	*Data Source*	California Energy Commission (CEC) Staff 2009 Final Report: "Comparative Cost of California Central Station Electricity Generation Technologies" CEC-200-2009-017-SD	Renewable Portfolio Standard (RPS) Calculator V6.1; Long-Term Procurement Plan (LTPP) CPUC CAISO 2024, Trajectory scenario	2
5		*Demand Measure*	Peak kW	Peak kW	2
6		*Units*	$ per kW-year	$ per kW-year	2
7		*Costing Methodology*	A 6-year levelized capacity cost net of gross margin. Resource balance year = 2018. Using PG&E's public Avoided Cost Model with an existing combined cycle unit for 2014-2017 and a new combustion turbine for 2018-2019. Reflects the difference between the annualized capital cost of a unit and the net energy benefits the unit earns in the energy market.	A 6-year levelized capacity cost net of gross margin. Resource balance year = beyond 2022. Using PG&E's public Avoided Cost Model with an existing combined cycle unit for 2017-2022. Reflects the difference between the annualized capital cost of a unit and the net energy benefits the unit earns in the energy market.	2

TABLE 1-2
OVERVIEW OF PROPOSED MARGINAL TRANSMISSION AND DISTRIBUTION CAPACITY COSTS: DATA SOURCE, UNITS AND CALCULATION METHODOLOGY

Line No.	Function		Last Adopted Methodology	Proposed Methodology	Chapter
1	Marginal Transmission Capacity Costs (MTCC)	*Data Source*	CAISO-filed PG&E transmission investment plans	CAISO-filed PG&E transmission investment plans	3 and 4
2		*Costing Methodology*	Regression Method	Discounted Total Investment Method (DTIM)	
3		*Demand Measure*	Peak kW	Peak kW	
4		*Units*	$ per kW-year	$ per kW-year	
5	Marginal Demand-Related Primary and Secondary Distribution Capacity Costs (MDCC)	*Data Source*	Area-specific investment plans and projections based on accounting data	Area-specific investment plans and projections based on accounting data	5 and 6
6		*Costing Methodology*	Regression Method	Discounted Total Investment Method (DTIM)	
7		*Demand Measure*	Peak kW	Peak kW	
8		*Units*	$ per kW-year	$ per kW-year	

TABLE 1-3
OVERVIEW OF PROPOSED MARGINAL CUSTOMER ACCESS COSTS
DATA SOURCE, UNITS AND CALCULATION METHODOLOGY

Line No.	Function		Last Adopted Methodology	Proposed Methodology	Chapter
1	Marginal Customer Access Costs (MCAC): New Customer Connection Component	*Data Source*	Typical jobs from COMRESS estimating tool	Class-specific new connection cost database from Customer Contract Billing System and other sources	7
2		*Costing Methodology*	New Customer Only Cost (NCO)	Rental Method	
3		*Demand Measure*	Net changes in billed customers	Number of new customers	
4		*Units*	$ per Customer	$ per Customer	
5	Marginal Customer Access Costs (MCAC): Ongoing Revenue Cycle Services (RCS) Costs	*Data Source*	Embedded costs as proxy for marginal costs	Class-specific costs, Subject Matter Experts	8
6		*Costing Methodology*	Embedded costs as proxy for marginal costs	Incremental costs per Activity-based Costing analysis, with significant improvements in RCS data and methodology. Now includes the “other accounts 903 costs”	
7		*Unit of Demand*	Number of customers	Number of customers	
8		*Units*	$ per Customer-Year	$ per Customer-Year	

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

MARGINAL GENERATION COSTS

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CHAPTER 2
MARGINAL GENERATION COSTS

A. Introduction and Summary

The purpose of this chapter is to present Pacific Gas and Electric Company's (PG&E) estimates for the two components of its marginal generation costs (MGC). The marginal costs associated with a change in customer electricity usage include both an energy-related component and a capacity-related component. These two components are: (1) marginal energy costs (MEC) in cents per kilowatt-hour (¢/kWh); and (2) marginal generation capacity costs (MGCC) in dollars per kilowatt-year ($/kW-year). The MEC is calculated for five TOU rate periods and three voltage levels. MGCC is calculated for three voltage levels.[1]

1. Definition

The MEC reflects changes in generation costs associated with customers' energy usage—specifically, MEC is the cost of procuring electricity to meet one additional megawatt-hour (MWh) of load. The MGCC reflects changes in generation costs associated with customers' coincident peak demand—specifically, MGCC is the cost of procuring capacity to meet one additional megawatt of peak load. The MCG presented in this chapter are thus estimates of the change in PG&E's procurement costs that would be caused by small changes in customer energy usage and peak demand. They are not intended to provide estimates of PG&E's *average* or *total* electric procurement costs.

In General Rate Case (GRC) Phase II proceedings, the California Public Utilities Commission (CPUC or Commission) generally addresses estimates of both MEC and MGCC for the Investor-Owned Utility to determine the generation-related rate components for retail electric rates. Using both MEC and MGCC is an efficient approach for allocating PG&E's generation costs and providing the appropriate price signals to customers.

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[1] The MGC recommended in this testimony are not applicable for determining Qualifying Facility short-run avoided costs or as-delivered capacity prices.

2. Workshop

As one result of the settlement agreement adopted by the CPUC in PG&E's 2014 GRC Phase II,[2] PG&E conducted a public workshop on November 16, 2015, to explore publicly-available models and data that could be used to calculate MGC in PG&E's 2017 GRC Phase II proceeding.

3. Methodology

For the 2017 GRC Phase II, as in the 2014 GRC Phase II, PG&E's proposed MEC and MGCC are based on both publicly-available inputs and a publicly-available model. By relying on public data sources for its inputs and using models for avoided energy and capacity that can be shared publicly with all parties, PG&E is once again providing greater transparency.

a. Marginal Energy Cost

PG&E's MEC is calculated based on hourly power price forecasts for northern California for the period January 1, 2017 through December 31, 2022.[3] The hourly power price forecasts are based on the relationship between prices in the day-ahead and real-time (RT) markets of the California Independent System Operator (CAISO), and the load and generation in the CAISO. PG&E's MEC is calculated for

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2 See D.15-08-055.

3 In prior GRCs (e.g., 2014), PG&E considered MGC in the "test year" of the proceeding (i.e., 2014 for the 2014 GRC). Forecasted energy prices from 2017-2022 are used in the RA/RI model to calculate annual avoided capacity costs. In addition, prices from 2020 are used to compute MGC to determine TOU periods, while prices from 2017 are used to set rates.

the six TOU rate periods[4] and the three voltage levels[5] used by PG&E for revenue allocation and rate design.

b. Marginal Generation Capacity Cost

In previous GRC Phase II proceedings, the Commission indicated a preference for calculating MGCC using a longer-term perspective and adopted a 6-year planning horizon.[6] Using that precedent, PG&E has calculated its MGCC by levelizing six years of forecasted annual MGCCs from January 1, 2017 through December 31, 2022. PG&E's annual MGCCs are determined from the short-run costs of capacity for years prior to the resource balance year,[7] and from the long-run costs of capacity for the resource balance year and thereafter. For this GRC, the resource balance year is beyond 2022,[8] so PG&E's annual MCGG here is based solely on the short-run cost of capacity. The short-run cost of capacity for each year prior to the resource balance year is estimated by the going-forward fixed costs of an existing marginal generation resource net of its "energy gross margins"[9] for that year.

On and following the resource balance year, the long-run cost of capacity for each year would have been estimated using the levelized

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4 PG&E's proposed summer season runs from June 1 through September 30, and the proposed winter season runs from October 1 through May 31. The proposed summer peak period is from 5 p.m. to 10 p.m., all days of the week; the summer partial-peak period is from 3 p.m. to 5 p.m. and 10 p.m. to 12 p.m., all days of the week; and the summer off-peak period is midnight to 3 p.m., all days of the week. The winter partial-peak period is from 5 p.m. to 10 p.m., all days of the week; the super off-peak period is from 10 a.m. to 3 p.m. from March 1 through May 31, all days of the week; and the winter off-peak period is all other hours in the winter season. All hours are listed in Pacific Prevailing Time.

5 The three voltage levels are transmission (60 kilovolt (kV) and above); primary distribution (between 4 kV and 50 kV); and, secondary distribution (below 4 kV).

6 Re. PG&E, D.89-12-057, 34 CPUC 2d 199, 317 (1989).

7 The resource balance year is the year in which there will be insufficient existing resources to meet the capacity needs of the utility, so new resources will be required to meet the utility's capacity needs. It is also called the year of need.

8 Renewables Portfolio Standard (RPS) Calculator, V6.2, available at http://www.cpuc.ca.gov/RPS_Calculator/.

9 Energy gross margin is the expected market revenue net of variable cost. The variable cost includes fuel, start-up and variable operations and maintenance (O&M) cost.

real economic carrying charges that annualize the total fixed costs of a new marginal generation resource net of energy gross margins over the assumed asset life of the resource.

As in prior GRC proceedings, PG&E used the Peak Capacity Allocation Factor (PCAF) methodology to allocate MGCC to individual hours. The PCAF methodology is described in detail in Exhibit (PG&E-2), Chapter 9. PG&E has calculated its MGCC for three voltage levels.

4. Proposed Methodology Compared to Last Filed Methodology

Table 2-1 summarizes data sources and calculation methodologies used by PG&E in both the previous 2014 GRC Phase II proceeding and this proceeding.

TABLE 2-1
OVERVIEW OF PROPOSED MGC
DATA SOURCE, UNITS AND CALCULATION METHODOLOGY

Line No.	Function		PG&E's Methodology Submitted in the 2014 GRC Phase II	Proposed Methodology
1	MEC	*Data Source*	Applying historical market heat rates to the public market price forecast for natural gas and greenhouse gases (GHG). Historical market heat rates are based on the historical hourly prices in the CAISO Day-Ahead Market.	*Forecasting* market heat rates based on a model that is *calibrated* to historical market heat rates, using a public market price forecast for gas and GHG. Historical market heat rates are based on the historical hourly prices in the CAISO market.
		Demand Measure	kilowatt-hour (kWh) by TOU period	kWh by TOU period
		Units	¢/kWh	¢/kWh
2	MGCC	*Data Source*	California Energy Commission (CEC) Staff 2009 Final Report: "Comparative Cost of California Central Station Electricity Generation Technologies" CEC-200-2009-017-SD	RPS Calculator V6.1; Long-Term Procurement Plan (LTPP) CPUC CAISO 2024, Trajectory scenario
		Demand Measure	Peak kilowatts (kW)	Peak kW
		Units	$/kW-year	$/kW-year
		Costing Methodology	A 6-year levelized capacity cost net of gross margin. Resource balance year = 2018. Using PG&E's public Avoided Cost Model with an existing Combined Cycle (CC) unit for 2014-2017 and a new combustion turbine for 2018-2019. Reflects the difference between the annualized capital cost of a unit and the net energy benefits the unit earns in the energy market.	A 6-year levelized capacity cost net of gross margin. Resource balance year = beyond 2022. Using PG&E's public Avoided Cost Model with an existing CC unit for 2017-2022. Reflects the difference between the annualized capital cost of a unit and the net energy benefits the unit earns in the energy market.

5. PG&E's MEC and MGCC Results

Table 2-2 summarizes PG&E's proposed test year MEC averaged over the year 2017 and Table 2-3 summarizes PG&E's estimate of MGCC, levelized over the period 2017-2022.

TABLE 2-2 (REVISED)
MEC BY TOU RATE PERIOD
AND VOLTAGE LEVEL AVERAGED OVER YEAR 2017
(¢/KWH)

Line No.	TOU Rate Period	Voltage Level: Transmission	Primary Distribution	Secondary Distribution
1	Summer Peak	4.940	5.033	5.282
2	Summer Partial-Peak	3.791	3.862	4.053
3	Summer Off-Peak	2.665	2.715	2.850
4	Winter Partial-Peak	4.192	4.271	4.482
5	Winter Off-Peak[(a)]	2.409	2.454	2.575
6	Annual Average	3.062	NA	NA
7	Super Off-Peak	0.907	0.924	0.969

(a) Average includes Super Off-Peak hours.

TABLE 2-3
LEVELIZED MGCC BY VOLTAGE LEVEL FOR 2017-2022
($/KW-YR)[(a)]

Line No.	Period	Voltage Level: Transmission	Primary Distribution	Secondary Distribution
1	2017-2022 Levelized Cost	$28.64	$29.48	$31.25

(a) For PG&E's MGCC showing in its 2015 Rate Design Window (RDW) proceeding (Application (A.) 14-11-014), PG&E used a levelized MGCC from its 2014 GRC Phase II, with a resource balance year of 2018, which yielded a MGCC of $57.09/kW-yr. The reduction in this year's MGCC to approximately $30/kW-yr is caused by using a much later resource balance year, beyond 2022.

The remainder of this chapter provides more detail on the context and costing methodology of PG&E's MGC proposal.

B. Regulatory Context

In this proceeding, PG&E's MGC are used for retail rate design and allocating revenue requirements among PG&E's bundled electric customer classes. The MGC presented in this chapter—MEC and MGCC—are estimates of the changes in PG&E's electric procurement costs caused by small changes in customers' energy usage and coincident peak demand, respectively.

That is, MGC do not reflect PG&E's average electric procurement costs. The MEC is an estimate of the value of a marginal energy unit to customers, while the MGCC is an estimate of the value of the marginal capacity unit to customers. Economic theory indicates that pricing energy and capacity at the marginal unit cost of each should result in an efficient allocation among customers of both energy and capacity. When used in rate design and revenue requirements allocation, marginal costs reflect cost-causation and therefore send price signals that promote economic efficiency.[10]

C. Costing Methodology

1. Marginal Energy Costs

PG&E meets its energy needs by using a combination of resources including: its own generation assets; energy purchased under a mix of long-term power purchase agreements and generation resource contracts; and short-term power market purchases. Consistent with prior CPUC decisions, PG&E procures such resources through competitive solicitations, as appropriate.

However, to meet its residual needs, PG&E buys residual energy from the day-ahead and RT market operated by the CAISO. The CAISO economically dispatches resources that are bid into the markets. Because PG&E meets its residual needs by purchasing power in the CAISO day-ahead market, a forecast of day-ahead market prices provides the most relevant estimate of PG&E's future MEC.[11] Thus, PG&E calculates MEC by forecasting hourly prices for 2017-2022 based on historical day-ahead prices at the PG&E Default Load Aggregation Point (DLAP)[12] adjusted by

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10 See Exhibit (PG&E-2), Chapter 1 for explanation.

11 As explained below, PG&E actually considers a weighted average hourly price consisting of 90 percent of the day-ahead price plus 10 percent of the RT price (where the latter is averaged over 60, 5-minute intervals).

12 Prices at the PG&E DLAP represent the costs of PG&E's load. By contrast, prices at the North of Path 15 (NP15) and in between NP15 and SP15 (ZP26) hubs represent the prices paid to generators in PG&E's service territory. There are four DLAPs in the CAISO's territory, corresponding to the service territories of PG&E, Southern California Edison Company and San Diego Gas & Electric Company and a newly-instituted DLAP for Valley Electric.

the factors that impact the prices such as cost of natural gas and variable operations and maintenance (VOM).

a. What Drives Electricity Prices?

The hourly power price forecasting methodology is based on the observation that except during periods of over-supply or load-shedding, thermal (natural gas-fired) generators are almost always on the margin in California. Thus the hourly power price is a function of the residual load that must be met by gas-fired generation after accounting for production from baseload (nuclear) and renewable (wind, solar, geothermal, biomass, biogas, and hydroelectric generation (hydro)) generators, which have limited dispatchability and are essentially "must run", thus are rarely on the margin. PG&E calls the residual load "adjusted net load" (ANL). The ANL starts with the CAISO's Net Load calculation, which backs out wind and solar.[13] Then PG&E also subtracts nuclear, hydro and the other renewables (geothermal, biomass and biogas), because all of these displace thermal generation just as wind and solar do—and because the model that uses ANL fits the price data better than one that uses just Net Load.

PG&E's ANL model is a heat-rate based model[14] that forecasts a market heat rate and multiplies by a forecasted gas cost (which includes

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13 Net load is equal to measured gross load minus utility-scale wind and solar production. This is the quantity tracked daily on the CAISO's Renewables Watch web page, at http://www.caiso.com/Pages/TodaysOutlook.aspx#Renewables and made famous as the "duck chart," which the CAISO explains at http://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf. ANL is equal to net load minus nuclear production, geothermal and biomass/biogas production, and a smoothed function of daily average hydro production. ANL thus represents the residual load that must be met by non-hydro dispatchable resources such as thermal generators, imports and energy storage.

14 Heat rate is equal to energy price divided by gas cost, with units of MMBtu/MWh (Million British Thermal Units per MWh). A low heat rate is better, with the most efficient CC natural gas generators having heat rates close to 6,000 MMBtu/MWh, while an inefficient single-cycle gas generator that comes on only during heat waves might have a heat rate of 10,000 or more. A heat rate-based model of marginal energy prices was used in Energy and Environmental Economics, Inc.'s (E3) Avoided Cost Calculator, referenced in the 2007 Rulemaking 07-01-041, and a heat rate-based model of marginal energy prices was also used in PG&E's 2015 RDW Application (A.14-11-104). E3 explains its methodology at https://ethree.com/documents/CPUC%20DR/AvoidedCostDocumentation.doc.

the commodity cost, transportation cost and a GHG adder). Note that while the power and gas prices in the model correspond to the PG&E service territory, loads and generation correspond to the entire CAISO footprint.[15]

b. Hourly Energy Price Forecast Methodology

Estimating hourly MEC is an important step in determining accurate TOU periods and seasons. The highest and lowest MGC hours are used to identify candidate peak and off-peak periods, as well as the most appropriate definition of the summer season when costs and peak rates are the highest. MEC is affected by the significant changes to the hourly shape of ANL brought about by the increased penetration of variable renewable resources such as wind and solar. Already in 2015, the peak of ANL (and also the highest MEC hours) shifted to later in the day during all seasons and months of the year, and based on forecasts of increased renewables penetration these peaks are expected to shift even later.

1) Hourly MEC

PG&E calculates MEC by forecasting hourly prices for 2017-2022 based on a forecast of hourly market heat rates for those years at the PG&E DLAP adjusted by additional factors that impact the prices such as the cost of natural gas and GHG allowances, and VOM.[16] Given the changes in the market that have recently occurred and are expected over the next few years due to a significant addition of renewable generation, PG&E expects that hourly market heat rates will be significantly different from historical hourly market heat rates that were used in the 2014 GRC Phase II.

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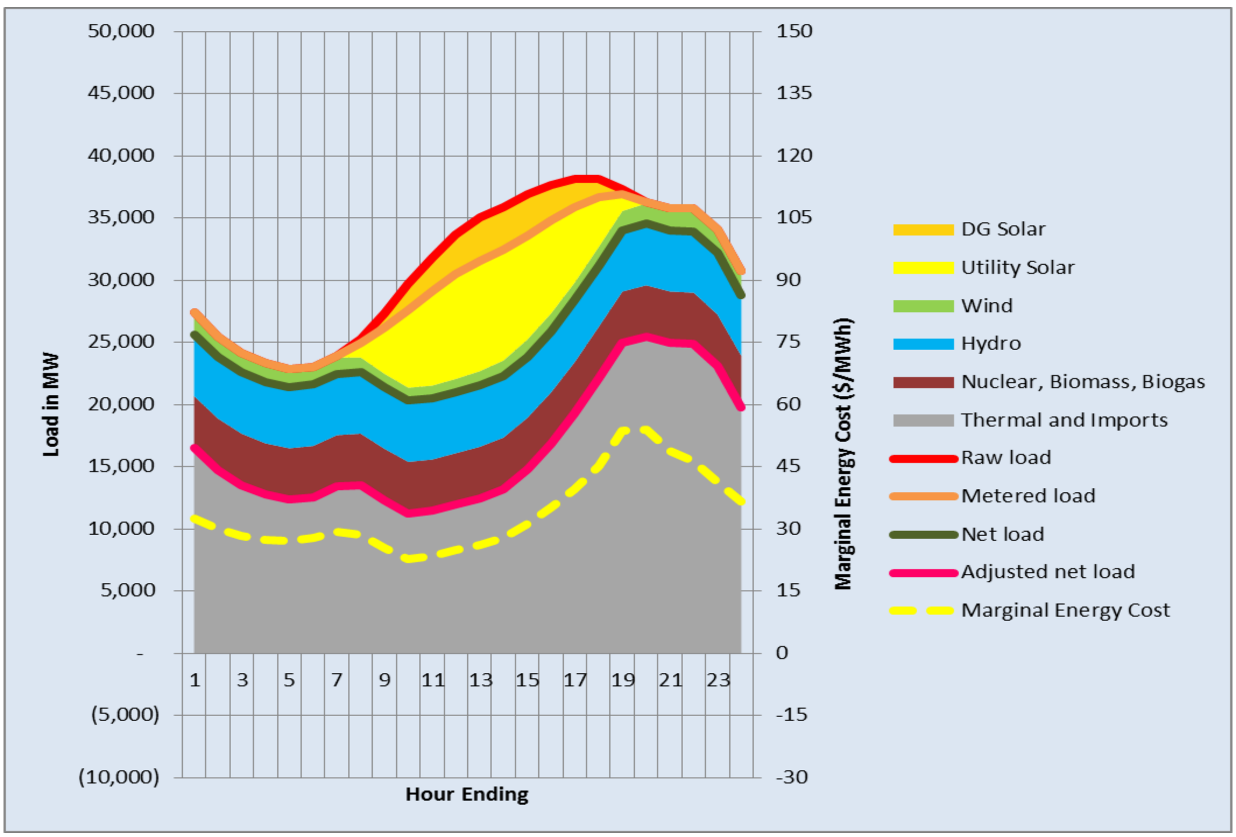
15 The appropriate prices to use for this application are at the PG&E DLAP. The PG&E DLAP prices are generally influenced by generation and load over the entire CAISO, rather than just in the northern region. For example, the majority of solar generation is located in the southern part of CAISO, and in the absence of significant congestion results in all such resources displacing thermal generation and therefore influencing marginal heat rates and prices throughout the CAISO's footprint.

16 PG&E uses an "Effective Market Heat Rate" (EMHR), which adjusts the standard heat rate for the cost of GHG allowances and VOM. Details of the calculation are explained below.

PG&E forecasted hourly market heat rates using publicly-available CAISO data by modeling the relationship between market heat rates and CAISO-wide ANL, which is described in detail below.

As shown in Figures 2-1 through 2-6, the average ANL and MEC forecasted in 2017 and 2020 have a very different shape from the average raw load, and also a different shape from the average metered or gross load.[17]

FIGURE 2-1
FORECASTED AVERAGE RAW, METERED, NET, AND ADJUSTED NET CAISO LOAD AND MEC, SUMMER 2017 (JUN-SEP; AVERAGE HYDRO)



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17 Raw load is equal to gross (metered) load plus rooftop photovoltaic (PV). The reason the analysis starts with raw instead of gross load, is that the hourly shape of raw load (that is, the load that would be present in the absence of rooftop PV) is likely to be more stable over time than the hourly shape of the gross load. PG&E therefore backed out rooftop PV from the load forecasts described below and assumed the hourly shape of raw load would remain constant, then incorporated forecasts of rooftop PV to obtain forecasts of gross load whose hourly shape changes as rooftop PV increases.

FIGURE 2-2
FORECASTED AVERAGE RAW, METERED, NET, AND ADJUSTED NET CAISO LOAD AND MEC, SUMMER 2020 (JUN-SEP; AVERAGE HYDRO)

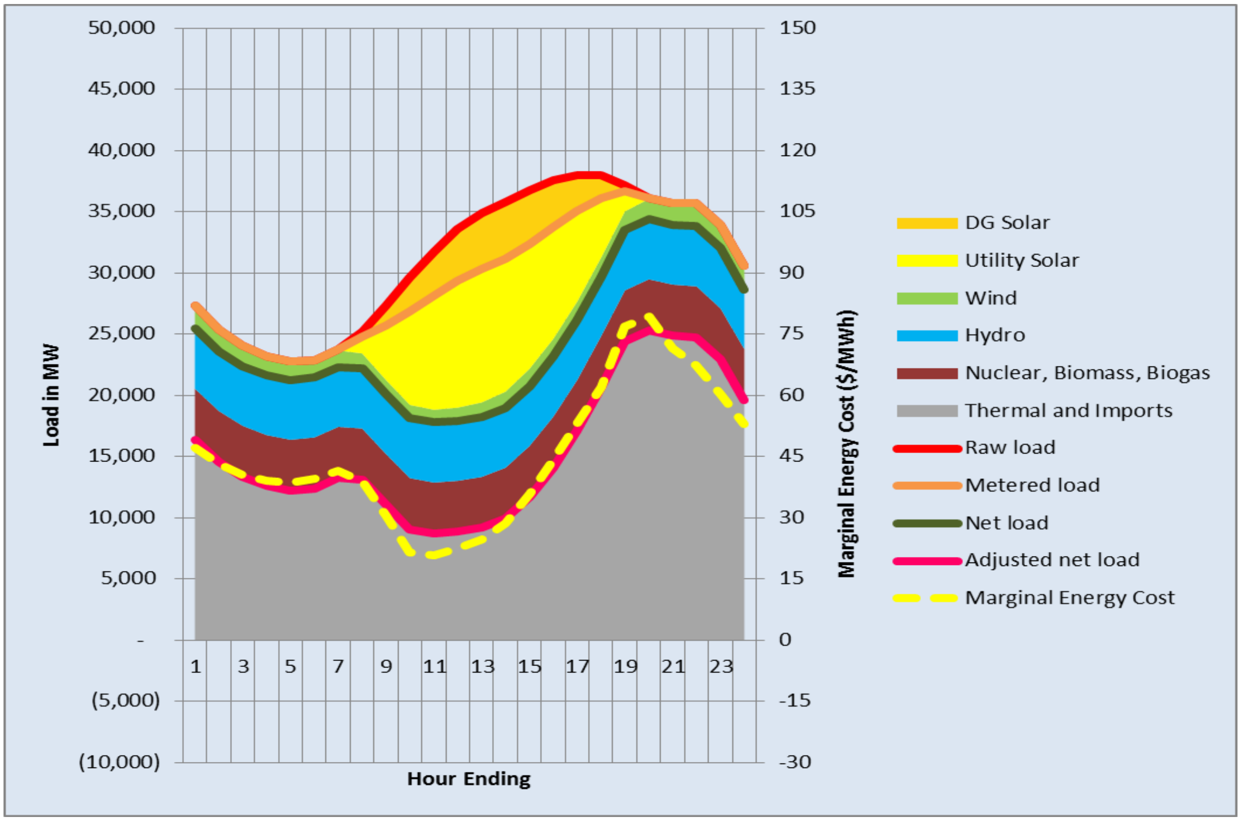


FIGURE 2-3
FORECASTED AVERAGE RAW, METERED, NET, AND ADJUSTED NET CAISO LOAD AND MEC, WINTER 2017 (JAN-FEB, OCT-DEC; AVERAGE HYDRO)

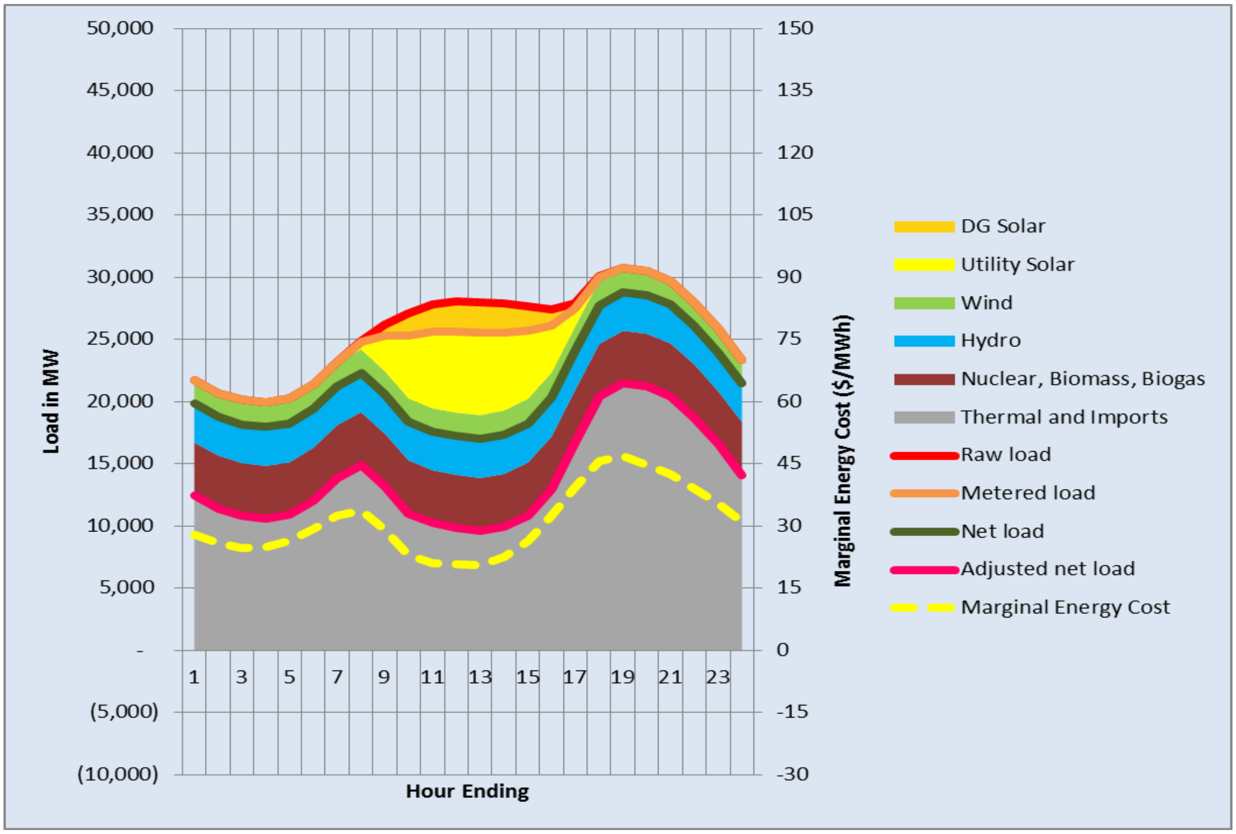


FIGURE 2-4
FORECASTED AVERAGE RAW, METERED, NET, AND ADJUSTED NET CAISO LOAD AND MEC, WINTER 2020 (JAN-FEB, OCT-DEC; AVERAGE HYDRO)

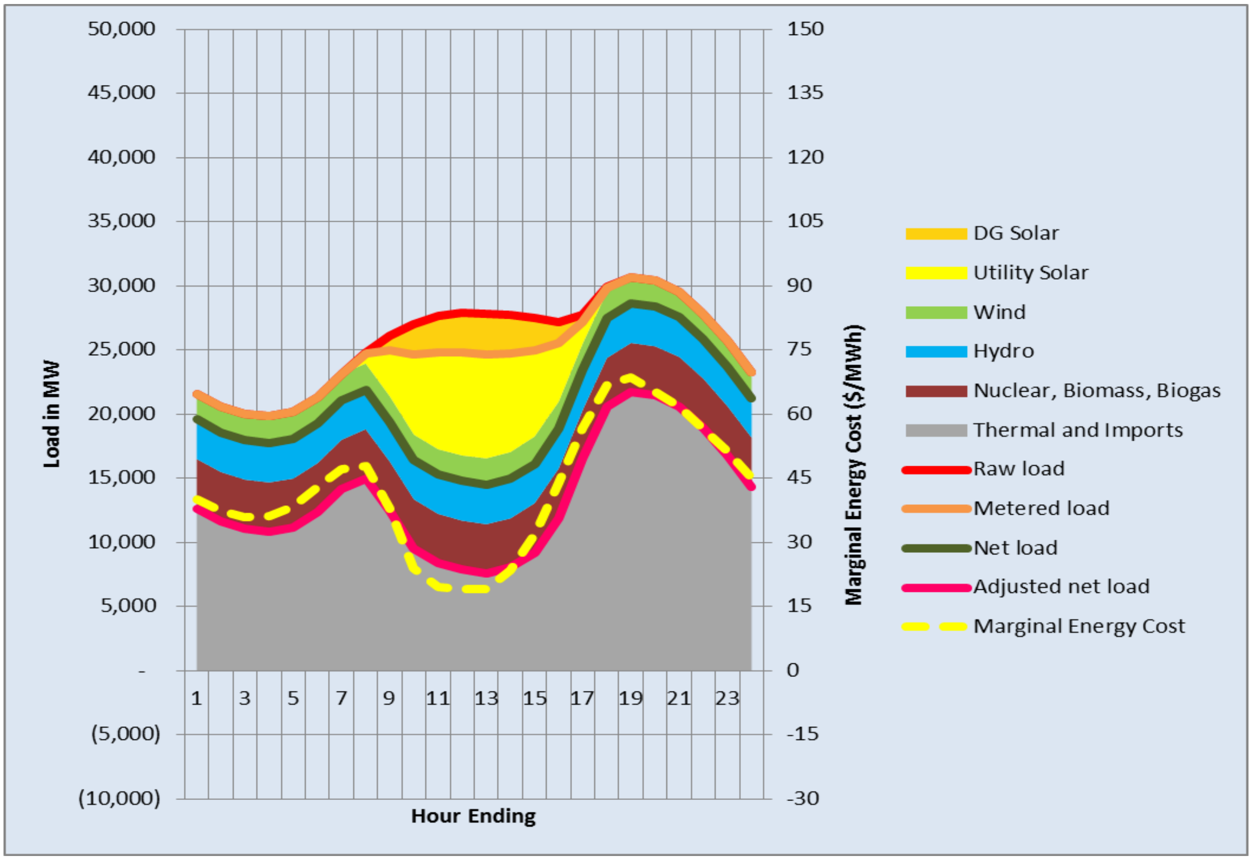


FIGURE 2-5
FORECASTED AVERAGE RAW, METERED, NET, AND ADJUSTED NET CAISO LOAD AND MEC, SPRING 2017 (MAR-MAY; AVERAGE HYDRO)

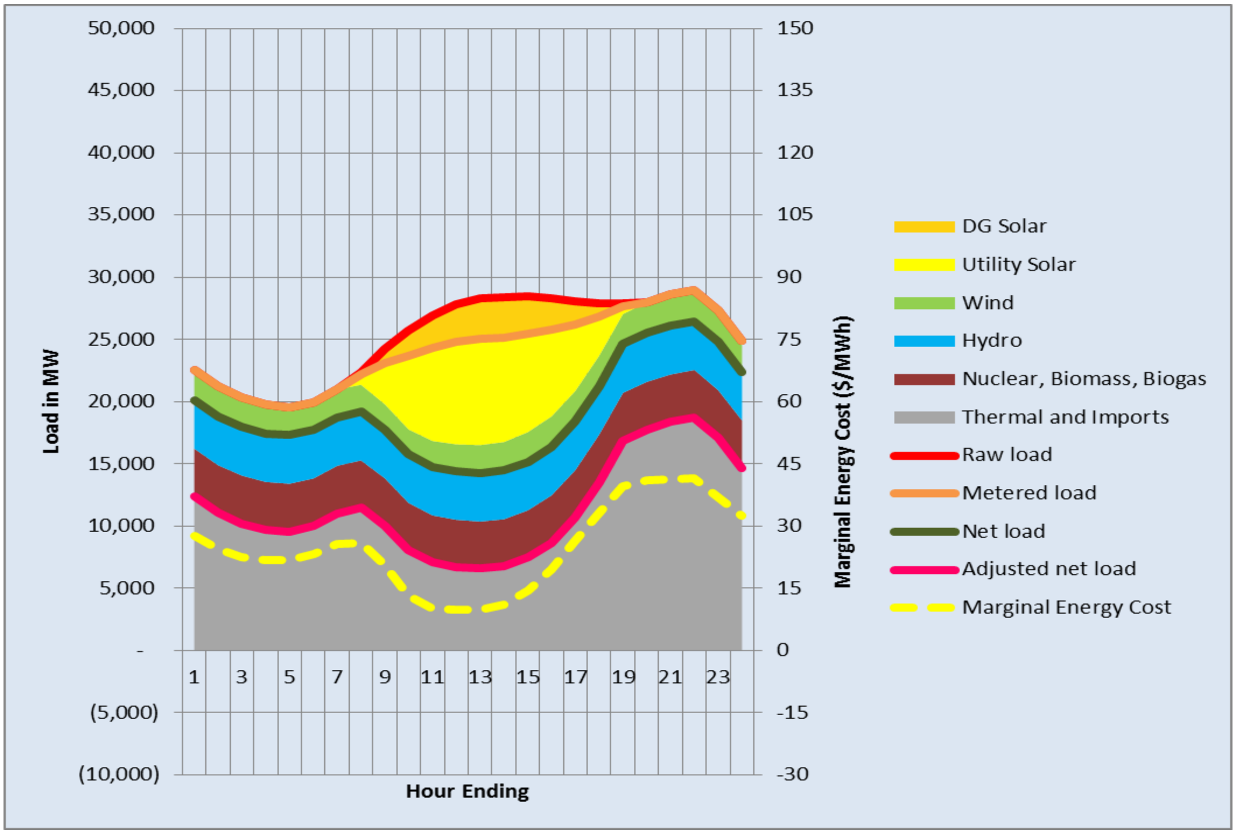
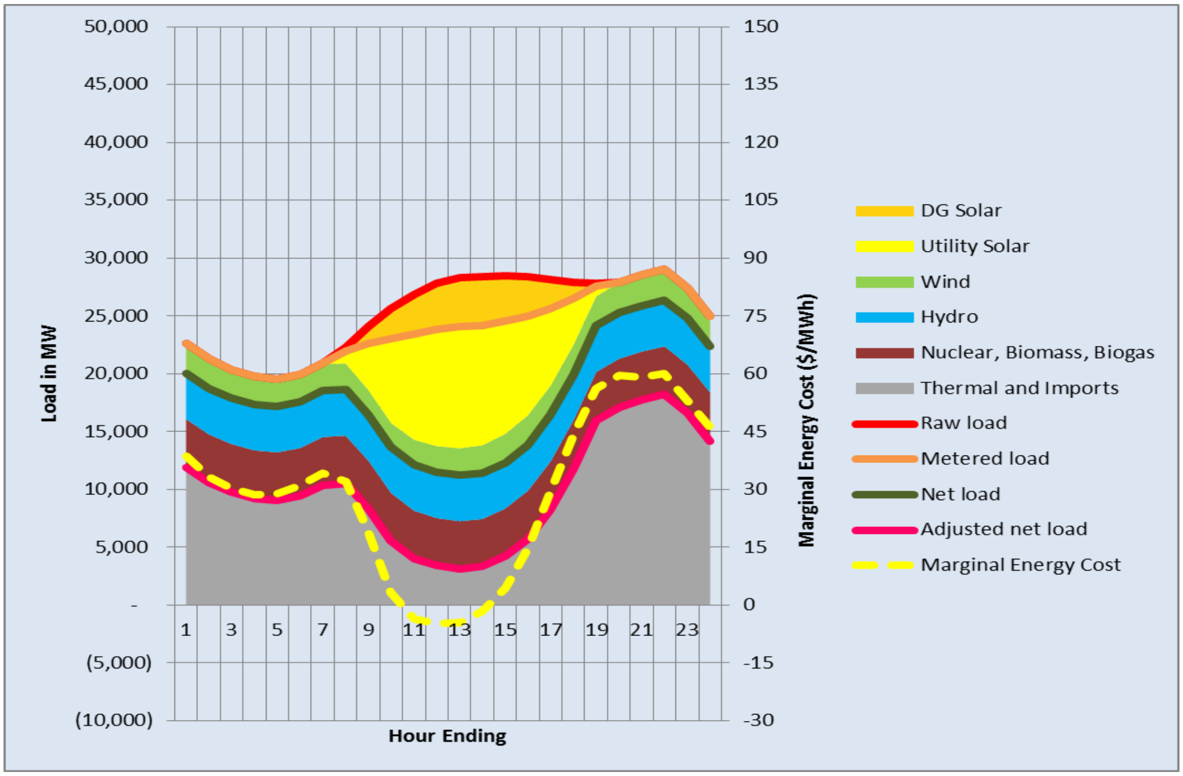


FIGURE 2-6
FORECASTED AVERAGE RAW, METERED, NET, AND ADJUSTED NET CAISO LOAD AND MEC, SPRING 2020 (MAR-MAY; AVERAGE HYDRO)



The significant forecasted solar production leads to an obvious peak in average ANL in the evening, and a minimum in average ANL (and MEC) close to mid-day in all seasons.

2) Methodology

For a region such as California, where thermal (gas-fired) units are generally on the margin,[18] the heat rate of the marginal gas-fired generator usually sets the energy price. Thus, an effective

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18 Except for hours in which the ANL is less than the minimum generation level or greater than the maximum generation level of on-line thermal generators, a marginal additional MW of load will generally be met by increasing the generation at the on-line thermal generator with the lowest marginal heat rate. When the ANL is greater than the maximum generation level of on-line thermal generators additional load may be met by reducing other load via demand response, or in extreme situations via load shedding. When the ANL is less than the thermal generators' minimum generation level (a situation the CAISO calls "oversupply"), additional load may reduce the renewable curtailment that is required during oversupply to balance the CAISO system. Thermal generators are forecasted to be on the margin for more than 93 percent of the hours in 2020 (assuming that prices less than zero indicate renewable curtailment, while prices above $200/MWh indicate demand response or load shedding).

way to model energy prices is via the marginal heat rate times an assumed gas price, with further adjustments for VOM and GHG costs, and both a “soft floor” and a “hard floor” to represent curtailment of renewable and some baseload generation.

To calculate MEC during the forecast period, PG&E combined a set of forecasted hourly market heat rates with a natural gas cost forecast and VOM costs. Specifically, PG&E calculated energy prices for northern California for each hour as:

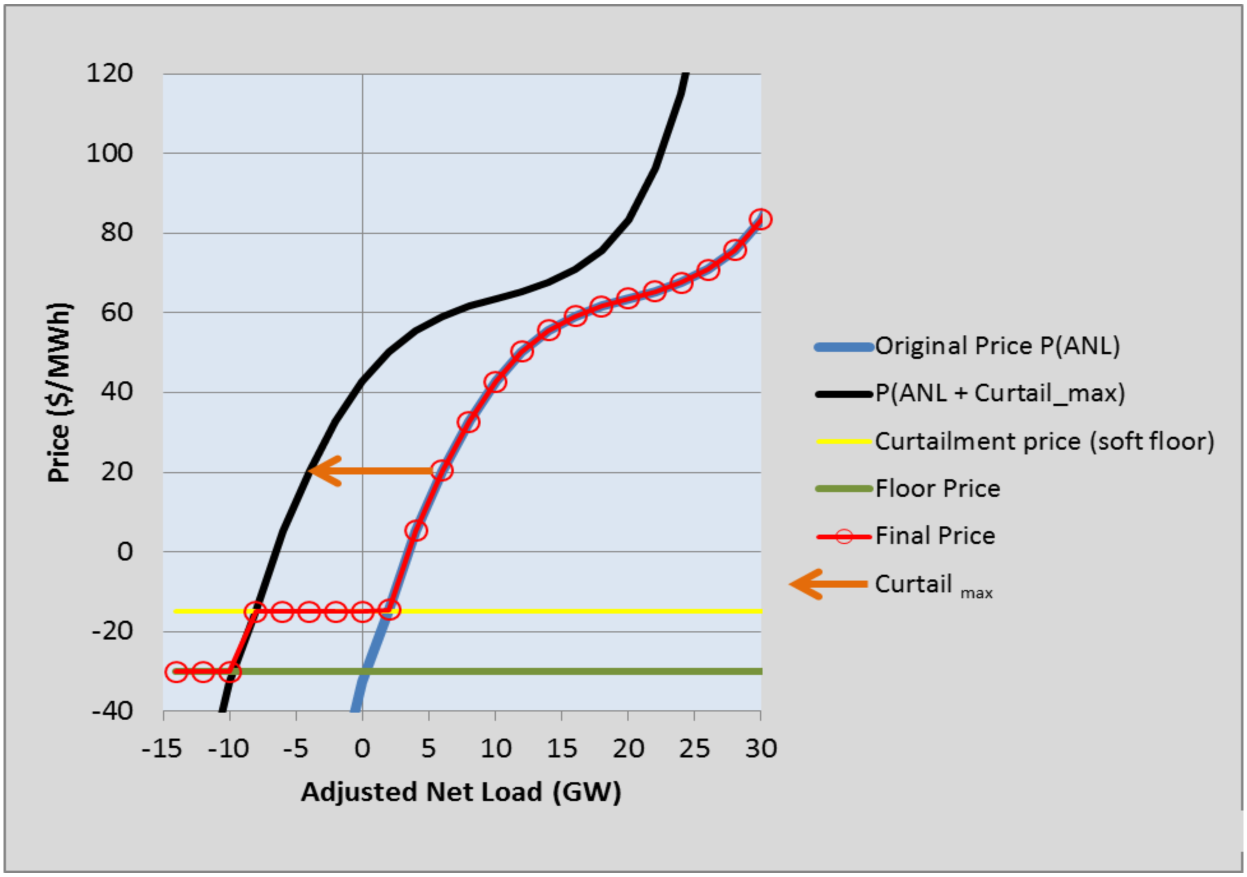
$$\text{Max}\ \{-30, \text{Min}\ [\ P(ANL + Curtail_{max}), \text{Max}\ (-15, P(ANL))]\}$$

Where

- $P(x)$ = [Hourly EMHR Forecast(x)] · [Gas Cost + GHG] + [VOM]);
- $Curtail_{max}$ – is the maximum amount of utility-scale generation that is forecast to be curtailable at a price of (-$15/MWh);
- Gas Cost – is the monthly gas price forecast at PG&E Citygate burner-tip; and
- GHG – is forecasted emission costs, converted to $/MMBtu.

This function is illustrated in Figure 2-4 below.

FIGURE 2-7
ILLUSTRATIVE PRICE CURVE WITH CURTAILMENT PRICE AND FLOOR PRICE



In Figure 2-7, the blue curve shows the price function P(ANL) while the black curve shows the function P(ANL + $Curtail_{max}$), which is shifted to the left by $Curtail_{max}$. With lower and lower ANL, as the original price curve reaches the "soft floor" of -$15[19] the price stays at the curtailment price until the limiting amount of curtailment is

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19 In the first four months of 2016, the RT price at the PG&E DLAP was between -$13 and -$18 over 1357 intervals (of five minutes each). The RT price was lower than -$18 in only 367 intervals, and between -$13 and $0 in 1092 intervals. PG&E's conclusion is that RT curtailment currently occurs primarily when the RT price reaches approximately -$15/MWh. This effect is illustrated in the CAISO's presentation "CAISO's proposed TOU periods to address grid needs with high numbers of renewables" to the TOU OIR Workshop on February 26, 2016, in which Slide 14 shows RT prices generally around -$15 between 8:30 a.m. and 4 p.m. on February 21, 2016, a day in which a total of 2,701 MWh of renewables were economically curtailed (*see* http://www.caiso.com/Documents/CaliforniaISOProposedTime-of-UsePeriods-CPUC_2_26_2016_9am.pdf). In the absence of other information, PG&E assumes that this soft floor price stays constant in the future (in real dollars, i.e., it becomes more negative at the rate of inflation).

reached; then the price follows the shifted price curve until the floor price is reached. PG&E applied a price floor of -$30/MWh (negative $30/MWh) to consider the fact that additional renewable generation could be curtailed when prices go below -$30/MWh, and that over the long term, the CAISO market would adjust if prices went below that level for a significant number of hours per year (e.g., new energy storage devices might be built to take advantage of such low prices).

PG&E obtained Citygate burner-tip price forecasts from the Intercontinental Exchange (ICE) and United States Energy Information Administration, and GHG cost forecasts from the Preliminary 2015 Integrated Energy Policy Report (IEPR).[20]

3) Historical EMHR

To calculate hourly Effective Market Heat Rate forecasts, PG&E first calculated EMHR for every hour in the historical period from April 27, 2010 through April 30, 2016 as:

$$EMHR = [P – VOM] / [G + GTR + GHG],$$

[20] Values come from the Preliminary 2015 IEPR Production Cost Model Common Case Input Assumptions.

Where:

- P – is historical Locational Marginal Price for that hour at the PG&E DLAP from CAISO market price data;[21]
- VOM – is the Variable Operation and Maintenance Costs for the corresponding year;[22]
- G – is the historical natural gas prices at PG&E Citygate from the ICE for the corresponding day; and
- GTR – is the historical gas transportation rates (G-EG and G-SUR tariff) to burner-tip for the corresponding month.[23]

4) Modeling EMHR – Simple Model

Traditionally, the EMHR has been shown to follow a "hockey stick" relationship with the load: higher load results in the dispatch of a resource with higher variable cost, and as the load gets closer to the available capacity, inefficient single-cycle generators turn on and the marginal heat rate increases much more rapidly. However, in fact, EMHR would be more correlated with the amount of fossil resources (including imports) needed to generate in order to meet the load. To derive the proxy for that amount for the purpose of

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21 Obtained from the CAISO's Open Access Same-Time Information System website, http://oasis.caiso.com. While the vast majority of short-term energy is transacted in the Day-Ahead market, between five and 10 percent of the energy is transacted in the 5-minute RT market. Also, most of the curtailment of renewables occurs in the RT market due to both contractual considerations and uncertainty in day-ahead forecasts of load and non-dispatchable renewables. At the same time, both solar and wind generation are significantly under-scheduled in the Day-Ahead market (see slides 19-21 in CAISO's presentation at the May 17, 2016 Market Performance Planning Forum, available at http://www.caiso.com/Documents/Agenda_Presentation_MarketPerformance_PlanningForum_May172016.pdf). Finally, while the Day-Ahead prices result from a CAISO market algorithm that considers day-ahead forecasts of load and generation, the MEC price model is calibrated to actual load and generation that occur in RT (i.e., not the forecasted values). Based on all these factors, PG&E used a weighted average of 90 percent Day-Ahead and 10 percent smoothed RT price to compute the EMHR. Using this weighted average price rather than the Day-Ahead price alone improved the R-squared of the fit from 82.7 to 83.6 percent and reduced the mean absolute error (MAE) over the historical period from $3.63 to $3.48.

22 This was set from the 2009 VOM cost of a generic combustion turbine, escalated by 2 percent annually to get 2014 costs of $4.67/MWh (and 2020 costs of $5.26/MWh). The costs and inflation rates are chosen from the 2009 CEC Cost of Generation Report.

23 http://www.pge.com/nots/rates/tariffs/GRF.SHTML modeling EMHR, PG&E defines ANL as net load (gross load minus utility-scale wind and solar generation) minus nuclear, biomass and geothermal generation and a factor h times the 30-day rolling average of hydro generation.[24] The 30-day rolling average of daily hydro generation is intended to capture the average amount of hydro generation that is available for dispatch in each hour, while the factor h (which is greater than 1) captures the additional impact of hydro generation due to its flexibility (e.g., provision of ancillary services such as spinning reserve and regulation).

Figure 2-8 shows the relationship of EMHR to ANL over the historical period April 27, 2010 through April 30, 2016. The graph shows that the EMHR slowly increases with ANL when it is below about 10 MMBtu/MWh, while it rapidly increases with ANL when it is above 10 MMBtu/MWh. Also the functional shape is a little steeper as you go to the far left on ANL. This observation leads to modeling EMHR as the sum of an exponential function (that dominates in the steep right part) and a cubic function (that dominates in the middle and left parts) of ANL. Specifically, PG&E used the following functional form to model EMHR one hour at a time (i.e., without including ramping or other intra-day effects):

$$EMHR = b1 \cdot Exp(b2 \cdot ANL_c) + a3 \cdot ANL_c^3 + a1 \cdot ANL_c + a0 + e$$

<u>Where</u>:

- ANL_c = Centered[25] ANL;

  <u>Calculated As</u>:

  - $ANL_c = L - RS - US - W - h \cdot H - N - c$;

    <u>Where</u>:

    - L = hourly raw load in the CAISO system (i.e., assuming no rooftop solar generation);

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[24] CAISO and the 2014 LTPP forecast list large hydro and small hydro separately; in this analysis they are summed to represent the total hydro resources dispatched within the CAISO footprint.

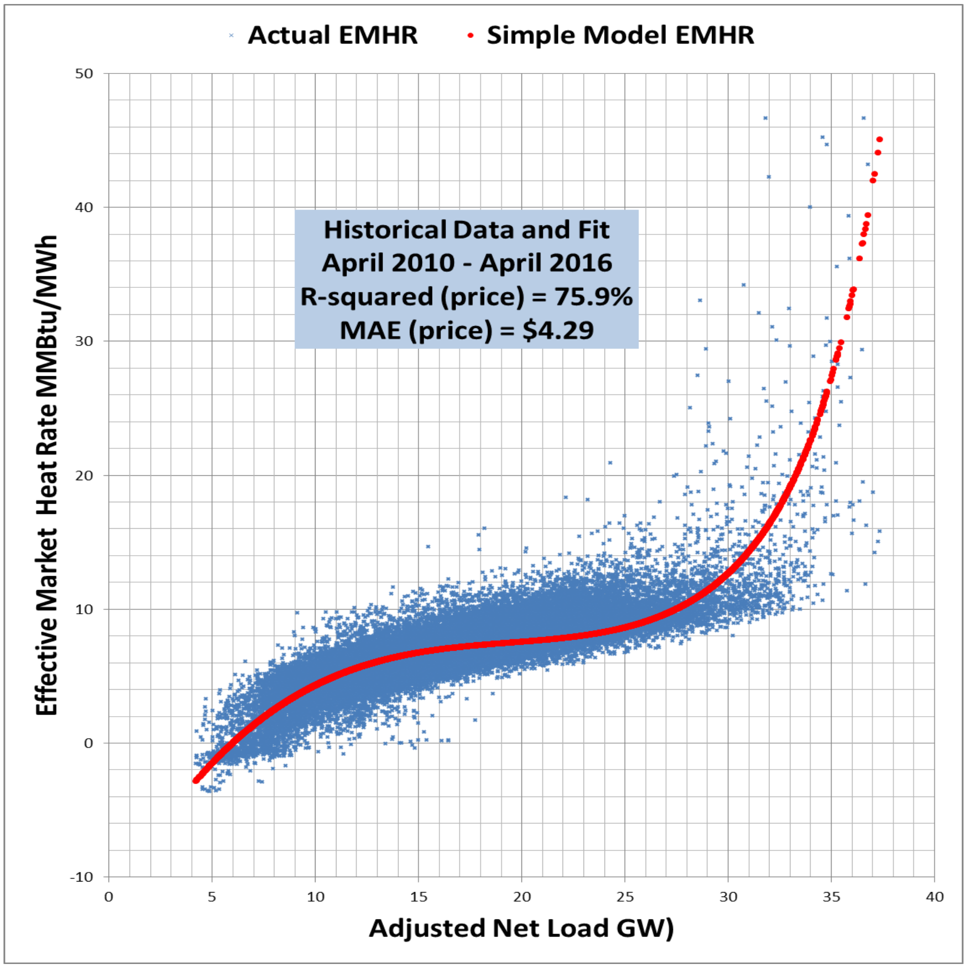
[25] The center parameter acts to shift the S-curve to the right or left to match the characteristics of the thermal fleet. It also allows the use of a cubic term without a corresponding quadratic, leads to faster calibration, and keeps the magnitude of the other coefficients in the range of 0 to +10.

- RS = hourly rooftop solar generation in the CAISO system;[26]
- US = hourly utility-scale solar generation in the CAISO system;
- W = hourly wind generation in the CAISO system;[27]
- H = 30-day moving average of daily average hydro in the CAISO system;
- N = hourly nuclear plus biomass/biogas plus geothermal generation in the CAISO system; and
- e = Residual.

[26] In the historical dataset, neither L nor RS are available, only their difference (L-RS), which is equal to gross or metered load. In the forecast, both L and RS are available and they are tracked separately.

[27] 'US' includes imported solar generation, and 'W' includes imported wind generation. However, so-called firmed and shaped renewables are not included in these amounts, as they have a different effective generation profile from as-generated renewables. Firmed and shaped wind and (if any) solar generation are categorized as un-specified imports in both historical and forecasted datasets.

FIGURE 2-8
RELATIONSHIP OF EMHRs TO ANL
OVER THE PERIOD APRIL 27, 2010 THROUGH APRIL 30, 2016
(SIMPLE MODEL)



The Simple ANL Model consists of EMHR, which is Energy Price minus VOM, divided by Gas Price plus GHG adder. As shown above, PG&E's Simple Model yields modeled heat rates (shown in red in Figure 2-8) that fit the historical data (shown as blue crosses in Figure 2-8).

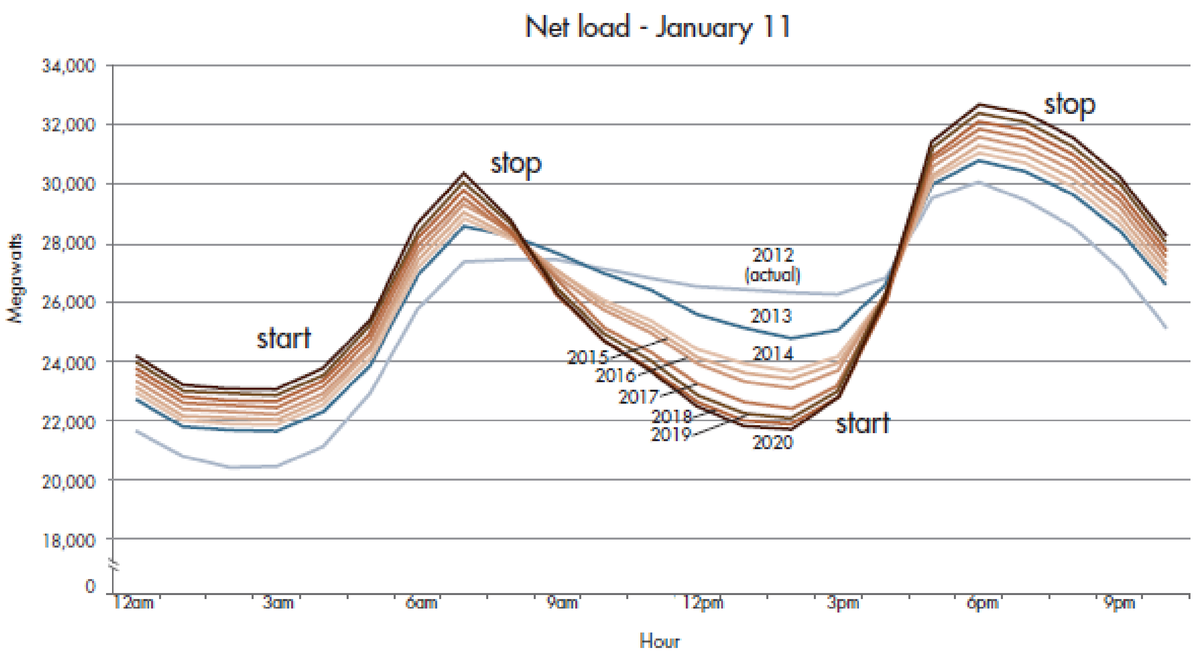
5) Ramping Effects

In PG&E's 2015 RDW Application (A.14-11-014), PG&E noted that thermal power plants require some time to ramp up generation, and typically need to be ramped up ahead of an increase in load.[28]

28 See Exhibit (PG&E-3), Chapter 3, FNs 4 and 5, received into evidence in PG&E's 2015 RDW testimony (A.14-11-014).

As the CAISO explains in their description of the Duck Chart, the ISO needs to dispatch resources to follow two upward and two downward ramps per day, with the most significant ramp being the upward ramp close to sunset (see Figure 2-9).

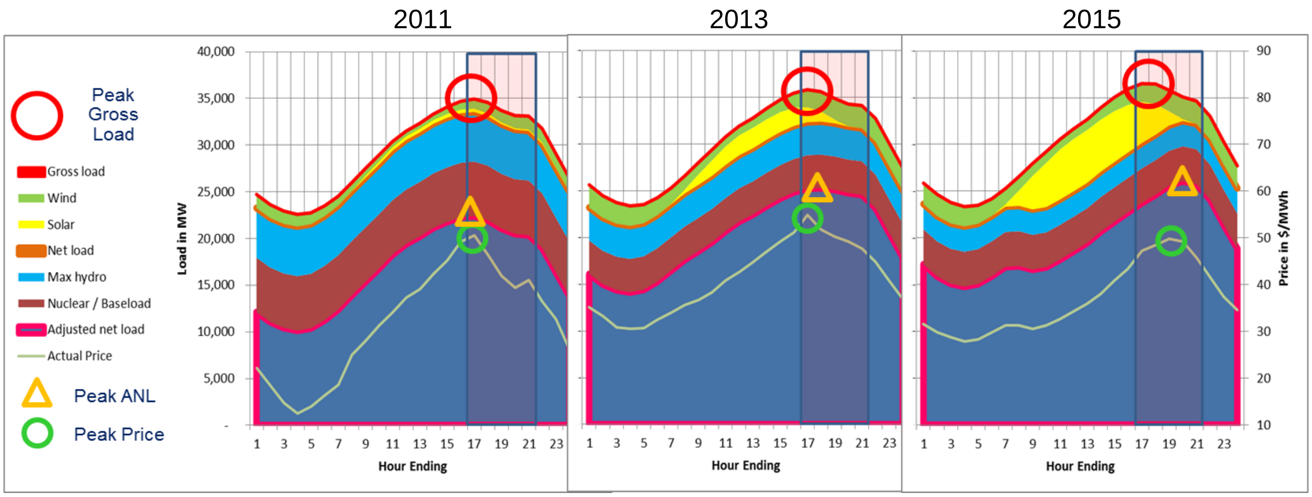
FIGURE 2-9
NET LOAD IN JANUARY SHOWING UPWARD AND DOWNWARD RAMPS[(a)]



(a) Taken from Figure 1 in CAISO's explanation of the Duck Chart, available at http://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf.

The upward ramps tend to increase hourly energy prices (i.e., marginal costs) when the load that those generators need to meet (i.e., the ANL) is increasing quickly. Likewise, downward ramps in ANL tend to depress prices. The impacts of increasing solar generation and of the ramp on prices can be seen in Figure 2-10, which shows average load, generation and hourly prices at the PG&E DLAP during the summers of 2011, 2013 and 2015.

FIGURE 2-10
RELATIONSHIP OF LOAD, GENERATION AND RAMPS WITH ENERGY PRICES DURING SUMMER (JUNE-SEPTEMBER) IN 2011, 2013 AND 2015



First, considering the impact of increasing solar generation, the red circles show the timing of the peak in metered, or gross load (which already accounts for the impact of Distributed Generation (DG), of which PV solar is an increasing part). The timing of that peak occurs right at the beginning of the 4 p.m. to 9 p.m. period outlined in tall blue rectangles, and stays essentially constant between 2011 and 2013, while shifting later by less than an hour in 2015. The slight "rightward shift" in the peak of gross load is caused by increasing amounts of distributed PV, which remove load during the middle of the day (as can be seen by the straightening of the red gross load curve in the later years compared to 2011).

A much more dramatic shift later in the day applies to ANL, which is highlighted by the orange triangles in Figure 2-10. The utility-scale solar generation (shown in yellow) displaces increasing amounts of thermal generation in 2013 and 2015 during the middle of the day, impacting the shape of the ANL curve (in bright pink) and shifting its peak later by about 3 hours, towards the end of the 4 p.m. to 9 p.m. period outlined by the rectangles.

Now when considering prices, the peak of the average prices (indicated by the light green curve) also shifts later in the day, but not as much as the ANL did—by 2015, the peak of average summer prices occurs close to an hour earlier than the peak of ANL. Thus a model that does not incorporate the impact of ramping is likely to show prices peaking too late.[29]

PG&E expanded the model described in Section 4) to include ramping by adjusting the centered ANL proportional to the centered 4-hour ramp.[30] The formula for centered ANL then becomes:

$$ANL_{cr} = L - RS - US - W - h \cdot H - N - c + r \cdot (ANL_{t+2} - ANL_{t-2})$$

Where:

- ANL_{t+2} is the ANL two hours later than the current hour and ANL_{t-2} is the ANL two hours prior to the current hour; and
- ANL_{cr} is the centered, ramp-modified ANL.

6) Intra-Day Spread

As discussed in footnote 30 and in the previous section, introducing a ramping effect improved the model fit, both in terms of sum of squared errors (SSE), and the timing of the peak. The model fit also improved in terms of reproducing the average spread between maximum and minimum price over a day. However, the modeled prices were still substantially flatter during the day than actual prices over the calibration period. This is likely due to the requirement for thermal generators to either start at least once per day or "ride through" a number of hours in which marginal costs are less than revenue (which now can occur during the middle of the day). Thus, energy prices (and thus marginal costs to load) are elevated during the top net load hours of each day and depressed during the lowest net load hours of each day, compared to how costs would develop in the absence of startup costs.

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29 PG&E took this into account in its 2015 RDW application, and chose a 4 p.m. to 9 p.m. peak rather than the 5 p.m. to 10 p.m. peak that was indicated based on its forecasted marginal costs partly because its price model in the 2015 RDW application did not incorporate ramping effects.

30 PG&E tested all combinations of ramp length from two to four hours, and all combinations of ramp timing from fully lagged (i.e., from current hour to hour t-l, where l is the lag time) to centered (i.e., from hour t + l/2 to t – l/2). The 4-hour centered ramp yielded the best combination of model fit in terms of sum of squared error and timing of the highest cost hour.

To incorporate this intra-day effect, the price model "boosts" the EMHR by a constant b in the top hour of each day, with lesser boosts in the 2nd, 3rd, etc. top hours—the other parameters of the model adjust to keep the mean the same when this effect is added. Mathematically, the formula for EMHR in Section 4) is modified as follows:

$$EMHR = b1 \cdot Exp(b2 \cdot ANL_{cr}) + a3 \cdot ANL_{cr}^{3} + a1 \cdot ANL_{cr} + a0 + b \cdot d^{(rankANL_{cr} - 1)} + e$$

Where:

- ANL_{cr} is the rank-adjusted centered ANL described above; and
- $rankANL_{cr}$ is the rank of the ANL_{cr} in the current hour out of all 24 hours of the day, and b and d are adjustable parameters (where the decay parameter d must be between 0 and 1).

7) Calibration

In order to find the parameters (a0, a1, a3, b1, b2, c, r, h, b, d) to best fit the function to the historical EMHR and ANL data, PG&E used optimization to solve for the parameters that minimize the sum of squared residuals e from the equation over the calibration period (April 27, 2010 through April 30, 2016),[31] with adjustments for matching the timing of the peak high cost hour, the early morning minimum, and the mid-day minimum over the last two calendar years of the calibration period (i.e., 2014 and 2015).[32]

The fitted parameters yield the following formula:

$$EMHR = 1.922 \times 10^{-2} \cdot Exp(3.65\ ANL_{cr}) + 1.525\ ANL_{cr}^{3} + 1.281\ ANL_{cr} + 6.80 + 2.68 \cdot 0.854^{(rankANL_{cr} - 1)} + e,$$

with the additional parameters:

- c = 1.982 (center parameter);
- h = 1.59 (hydro factor); and

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31 CAISO started publishing the full suite of hourly data that could be used to calculate ANL as of April 20, 2010. The first week of data were not used to allow for lag effects.

32 The exact formulae are provided in workpapers, which consist of Excel spreadsheets with all formulae intact.

- r = 0.122 (ramp coefficient).

This equation captures approximately 74 percent of the variability in EMHR over the calibration period (i.e., its R-squared is 74 percent), while the fitted prices capture 83.6 percent of the variability in day-ahead NP15 prices.[33] The average calibration error, measured as MAE over the calibration period, is $3.48. Incorporating ramping and intra-day boost into the model improved the R-squared by (83.6 – 75.9) = 7.7 percent, and reduced the MAE by ($4.29 - $3.48) = $0.81, or 19 percent compared to the Simple Model.

The effect of including ramping and intra-day boost effects in the model is illustrated in Figures 2-11 and 2-12. Figure 2-11 is similar to Figure 2-8, except that in this calibration the modeled EMHR can have multiple values for the same ANL; this is evidenced by the spread in the red modeled points around a general S-curve. Figure 2-12 is constructed differently—in that figure, each modeled (red) point has the ramping and boost adjustment removed (so all the red points now fall on a smooth curve); and each corresponding "actual" (blue) point has the same amount subtracted. Thus, the differences between modeled and actual EMHR are portrayed accurately in Figure 2-12, but both are adjusted to remove the ramp and boost effects. Note that the S-curve in Figure 2-12 has a slightly different shape (straighter) than the one in Figure 2-8, since ramping and boost effects take care of some of the variation in EMHR in the second calibration.

[33] Hourly energy prices show higher R-squared because gas prices are an excellent explanatory variable for energy prices, and gas prices had significant variability during the calibration period. However, this variation also implies that calibrating based on minimizing the errors in EMHR is preferred because it is more robust (insensitive to outliers) than calibrating based on prices themselves.

FIGURE 2-11
RELATIONSHIP OF EMHR TO ANL
OVER THE PERIOD APRIL 27, 2010 THROUGH APRIL 30, 2016
(INCLUDING RAMPING AND INTRA-DAY BOOST EFFECTS)

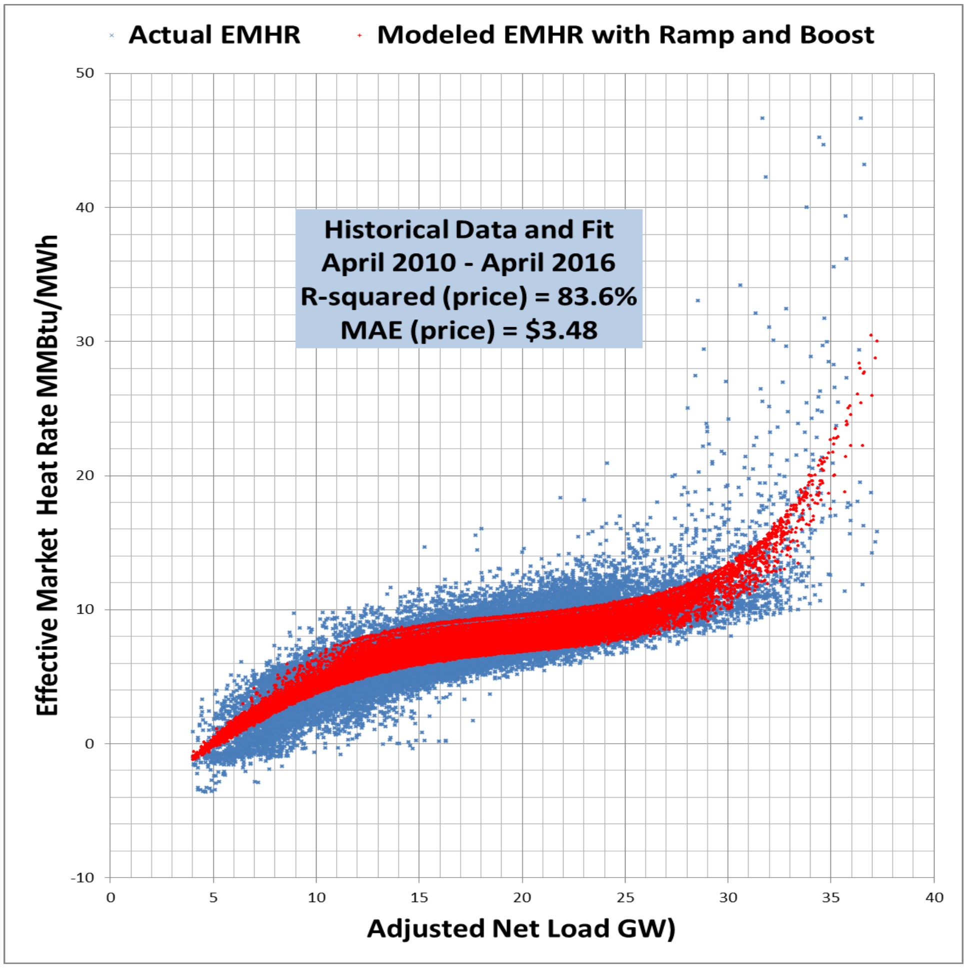
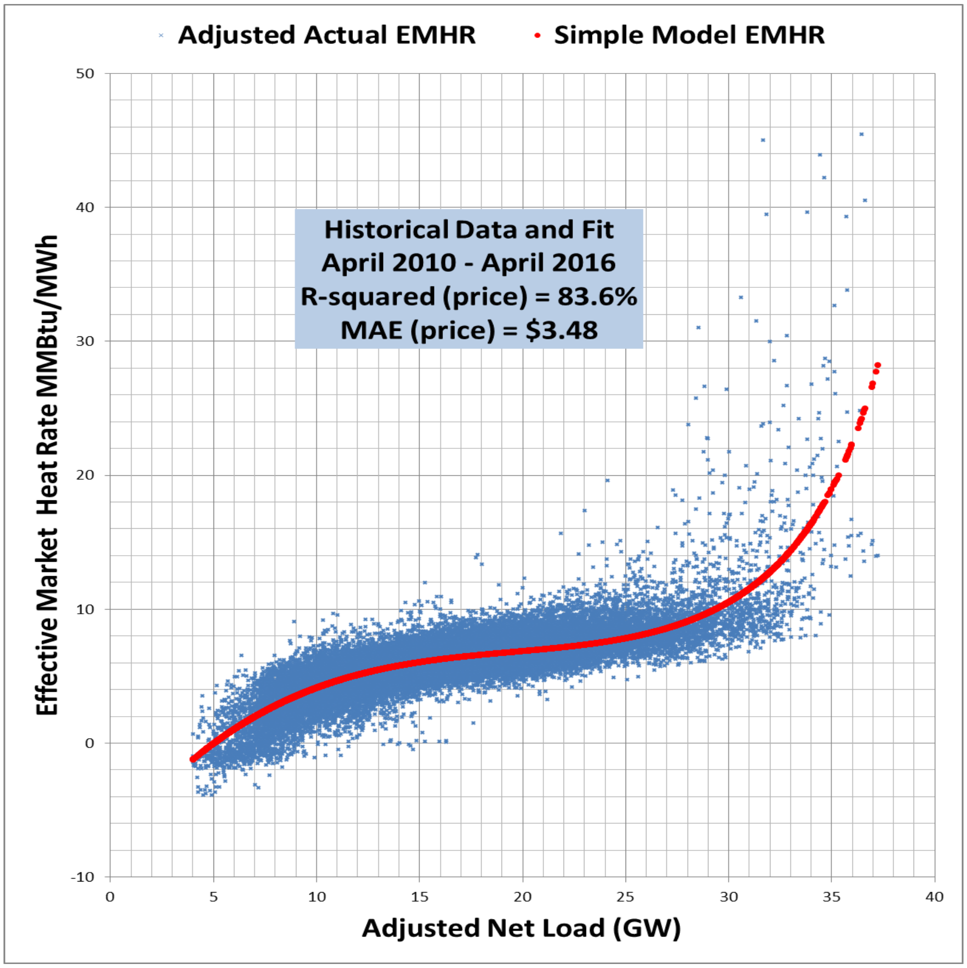


FIGURE 2-12
RELATIONSHIP OF RAMPING
AND BOOST-ADJUSTED ACTUAL EMHR TO ANL
OVER THE PERIOD APRIL 27, 2010 THROUGH APRIL 30, 2016



By way of comparison, an identical model that uses gross load instead of ANL as an explanatory variable (and is re-calibrated to find the optimal coefficients), captures only 52 percent of the variability in EMHR and 68 percent of the variability in price, and its MAE over the calibration period is approximately 45 percent worse at $5.05. The same (re-calibrated) model that uses net load instead of ANL captures 60.5 percent of the variability in EMHR and 73 percent of the variability in price, with MAE approximately 25 percent worse than the ANL-based model at $4.32.

8) Validation – Out of Sample Tests

To evaluate the robustness of the ANL price model, three out-of-sample (OOS) tests were performed. In the first test, the model was calibrated six times, and in each case a different year was left out of the sample for calibration (May 2010 through April 2011; May 2011 through April 2012; and so on). Goodness-of-fit statistics were computed over the OOS year's data and compared to the statistics when all years were included in the calibration. In the second test, the OOS periods were 2-years long (May 2010 through April 2012; May 2012 through April 2014; May 2014 through April 2016), while in the third test the OOS period consisted of half of the period of record (i.e., the model was calibrated based on data from 2010 through April 2013 with goodness of fit reported for May 2013 through 2016; and vice versa). The third test is an extreme one, in that it considers whether a model calibrated to a period with rising solar generation and low nuclear and hydro generation (2013-2016) can fit actual energy prices during a period with low solar generation and falling hydro and nuclear generation (2010-2013), and vice versa.

Results of the OOS tests are displayed in Table 2-4. To summarize the results, the model proved extremely robust, in that the MAE of the OOS datasets was only approximately 2.5 percent higher than the MAE when all data were included in the calibration (i.e., the MAE increased from approximately $3.48 in the complete calibration case to $3.57 in all three of the OOS tests). The SSE increased by 13 percent, 14 percent and 19 percent in the first, second and third OOS tests, respectively.

TABLE 2-4
GOODNESS OF FIT STATISTICS FROM OUT OF SAMPLE (OOS) TESTS

Line No.	Test #	Description	SSE	MAE
1		Original full-dataset calibration	73053	$3.483
2	1	Average of six OOS validations, each OOS sample 1-year long	82221 (+13%)	$3.575 (+2.6%)
3	2	Average of three OOS validations, each OOS sample 2-years long	83568 (+14%)	$3.575 (+2.6%)
4	3	Average of two OOS validations, each OOS sample 3-years long	87228 (+19%)	$3.572 (+2.5%)

Details of the results of the OOS tests, including re-calibrated coefficients from all of the samples, are provided in workpapers.

9) Forecast

In order to develop the forecasts for hourly market heat rates, PG&E applies the formula obtained in the calibration to the ANL forecast data for the period 2017-2022. PG&E derived hourly forecast data for individual ANL components as follows:

- Raw Load: based on annual forecasts from E3's RPS Calculator, Version (V) 6.2.[34] Hourly load shapes are consistent with the 2024 raw load shapes assumed in the PLEXOS® runs of 2014 LTPP Trajectory Scenario.[35]
- Wind: Annual total gigawatt-hours (GWh) based on RPS Calculator V6.2. Hourly wind generation shapes are consistent with ones assumed in the PLEXOS® runs of 2014 LTPP Trajectory case for 2024.
- Solar: Annual GWh of utility-scale solar based on annual solar generation forecast from RPS Calculator V6.2. Hourly utility-scale solar generation shapes are consistent

34 Available at http://www.cpuc.ca.gov/RPS_Calculator/. Details regarding location of data inputs within the RPS Calculator (i.e., tab and cells) are provided in workpapers.

35 PLEXOS® is a production simulation model that has been used by Independent System Operators including CAISO, utilities, and the Commission to model generation and transmission in California and elsewhere. Note that in this analysis we are using both the inputs to the 2014 LTPP Track 1A PLEXOS® runs, and (for the nuclear 8760 shape) the outputs from those runs.

with ones assumed in the PLEXOS® runs of 2014 LTPP Trajectory case for 2024.

- Rooftop PV Solar (Distributed) Generation: Annual GWh of rooftop PV solar based on annual DG PV generation forecast from RPS Calculator V6.2. Hourly rooftop PV solar generation shapes are consistent with ones assumed in the PLEXOS® runs of 2014 LTPP Trajectory case for 2024.[36]
- Hydro: Three scenarios were run for each forecast year, with hydro drawn from 2011 historical data (a wet year), 2012 (a slightly below-average year), and 2014 (a dry year). The final prices were computed as a weighted average of prices in the three scenarios, where the weights were chosen to reproduce the mean and standard deviation of the Sacramento-San Joaquin 8-Station Index over the period 1986-2015.[37] Details of the computation of weights are provided in workpapers.
- Nuclear: For this input, PG&E uses the generation profiles of Diablo Canyon Power Plant *output* from PLEXOS® runs of 2014 LTPP Trajectory case for 2024. Refueling outages were assumed to follow the same pattern of outages observed over the calibration period, with approximately 21 months between outages for each unit and each outage lasting 44 days.
- Geothermal, Biomass, Biogas: Annual total GWh based on RPS Calculator V6.2. Hourly generation shapes are assumed to be the same as nuclear (but without refueling outages).
- Curtailment: Some utility-scale wind and solar generation is assumed to be curtailed when the hourly price drops to negative

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36 Note that the shape of rooftop PV solar is close to but not identical to the shape of utility scale solar. They are treated separately in this model.

37 Note that the model actually has a better fit (higher R-squared) when the hydro effect is calculated using the factor h times a 30-day average of daily production rather than hourly hydro production. This is fortunate, because otherwise the model would have to forecast hourly hydro generation in 2017-22 assuming average/wet/dry hydro conditions, weather that aligns with the forecasted load and renewables output, and prices in the day-ahead market that reflect a later peak than occurred in 2011-2014.

$15/MWh, as described in footnote 19. The maximum amount that is subject to curtailment is equal to 1000 GWh per year as of 2015, plus all incremental generation in later years (i.e., it is assumed that all new future contracts for RPS-eligible generation will include unlimited curtailment provisions).[38]

c. Computing MECs at the Transmission Voltage Level by TOU Period

This process yields an hourly price forecast for wholesale market energy prices in northern California. PG&E's forecast of the 2017 average northern California energy price is $30.62/MWh for power delivered at the transmission voltage level.

PG&E estimated the MEC at the transmission voltage level for each of PG&E's six TOU periods as the average of the hourly electricity price forecasts weighted by the hourly 2014 PG&E system loads (time-shifted so that weekends line up between hourly prices and hourly loads).

d. Computing MEC at the Distribution Voltage Levels Using Energy Line Loss Factors

PG&E estimates the MEC at the primary and secondary distribution voltage levels for each TOU period by multiplying the appropriate energy line loss factors and the MEC at the transmission voltage level.[39] The line loss adjustment is necessary because the total amount of energy PG&E procures must be equal to the sum of: (1) the marginal energy consumed by customers, plus (2) the amount of energy that will normally be lost in the system due to line losses. Table 2-5 displays PG&E's current energy line loss factors. Table 2-6 shows how energy line losses are used to create the 2020 MEC by voltage levels.

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38 Note that in order to obtain bank financing, such contracts are generally "take or pay" contracts, in which the generator must be paid the same amount whether generation is curtailed or not.

39 The energy line loss factors are the same as those used in PG&E's Transmission Owner (TO)-13 rate filing at Federal Energy Regulatory Commission (FERC).

TABLE 2-5
TRANSMISSION AND DISTRIBUTION (T&D)
ENERGY LOSS FACTORS

		Percent Loss Factor	Energy Loss Factor	Cumulative Loss Factor	
				Meter to Generation	Generation to Meter
Line No.	Location	From Source Documents	1 / (1 - Percent Loss Factor)	Product of Loss Factors at Each Level	Inverse of Cumulative Loss Factors
1	Generator Bus Bar	0.000%	1.0000	1.0000	1.0000
2	Generation Tie	0.185%	1.0019	1.0019	0.9982
3	High Voltage (HV) Transmission	1.777%	1.0181	1.0200	0.9804
4	Low Voltage Transmission	1.544%	1.0157	1.0360	0.9653
5	Primary Distribution Output	1.847%	1.0188	1.0555	0.9474
6	Secondary Distribution	4.715%	1.0495	1.1077	0.9028

Source Documents:

– Transmission losses from May 14, 2010 "Transmission Loss Factors."

– Distribution losses from "Distribution Loss Values for the TO-8 Filing.

TABLE 2-6 (REVISED)
CALCULATION OF 2017 MEC
BY TOU RATE PERIOD AND VOLTAGE LEVEL
($/MWH)

Line No.	TOU Rate Period	Transmission MEC (Based on 2017 Hourly Market Price Forecast)	Multiplied by Primary Distribution Energy Loss Factor	Primary Distribution MEC	Multiplied by Secondary Distribution Energy Loss Factor	Secondary Distribution MEC
1	Summer Peak	49.40	× 1.0188 =	50.33	× 1.0495 =	52.82
2	Summer Partial-Peak	37.91	× 1.0188 =	38.62	× 1.0495 =	40.53
3	Summer Off-Peak	26.65	× 1.0188 =	27.15	× 1.0495 =	28.50
4	Winter-Partial	41.92	× 1.0188 =	42.71	× 1.0495 =	44.82
5	Winter-Off[(a)]	24.09	× 1.0188 =	24.54	× 1.0495 =	25.75
6	Super Off-Peak	9.07	× 1.0188 =	9.24	× 1.0495 =	9.69

(a) Average includes Super Off-Peak hours.

2. Marginal Generation Capacity Costs

a. Capacity Price Forecast Methodology

1) Model and Data Transparency

The methodology used by PG&E to develop its capacity price forecast is based on its internal avoided cost model. However, it has been re-designed to remove confidential information and to increase transparency. This model can be shared publicly with all GRC Phase II parties.

2) Principles

The MGCC represents the cost of a marginal resource for capacity. During the 6-year period (2017-2022) over which the annual MGCCs are levelized, the type of marginal resource for capacity can change, primarily when existing resources can no longer meet the demand for capacity and thus the market will need a new generation resource in that year.

The resource balance year represents the year in which there are insufficient existing resources to meet the capacity needs of the utility and, therefore, new resources will be required to meet the utility's capacity needs. In the near term (i.e., prior to the resource balance year), an existing generation resource will be the marginal resource and set the market price for capacity. In the long term (i.e., for the resource balance year and beyond), a new generation resource will be the marginal resource and set the market price for capacity.

However, because PG&E is forecasting a resource balance year beyond 2022, PG&E's MGCCs for the 6-year period, 2017-2022, are set using only the short-run cost of capacity.

3) Resource Balance Year

PG&E assumed 2040 as the resource balance year based on output from the RPS Calculator V6.2.[40]

4) Energy Gross Margins

To calculate short-run or long-run cost of capacity, the energy gross margin that a marginal resource is expected to earn from the spot energy market is subtracted from the fixed cost. To determine the energy gross margins of a marginal resource, PG&E used an options-based analysis to reflect uncertainties present in the market

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40 See tab 'System_Capacity.' System capacity is actually sufficient to meet the planning reserve margin (PRM) Need in 2040 with a significant buffer.

prices of power and gas. Variable costs were based on fuel costs, start-up costs and VOM costs. The hourly forward prices for energy were obtained from the same methodology used to derive the MEC described above. A generation resource was assumed to earn net energy market revenues (i.e., energy market revenues less variable costs) only when the electric energy price is higher than the variable costs. The Energy Gross Margin for each year was derived by taking the expected values of net energy market revenues during the year.

5) Short-Run Cost of Capacity for 2017-2022

a) Methodology

For each year from 2017-2022, PG&E estimated the short-run cost of capacity as the going-forward fixed cost[41] of the existing generation resource net of energy gross margins[42] it earns from the spot energy market. PG&E assumed an existing combined cycle gas turbine (CCGT) plant is the marginal unit prior to the resource balance year. PG&E used public data sources, including the RPS Calculator V6.1[43] and the LTPP CPUC CAISO 2024 Trajectory scenario[44] for inputs required to model an existing CCGT.

b) Fixed Cost of a CCGT

A Going-Forward Fixed Cost consists of Fixed O&M, insurance and property tax. Insurance and property tax are estimated based on the capital costs. To estimate an existing CCGT's capital cost, PG&E used $1,300/kW in 2015 dollars from the RPS Calculator. To estimate Fixed O&M for an

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41 Going-forward fixed costs consist of three components: (1) fixed O&M; (2) insurance and (3) property tax.

42 The energy gross margins represent expected operating profits from the market from the revenue that the facility earns from the energy market less the facility's variable operating costs incurred to produce energy.

43 http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=8635.

44 http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=9144.

existing CCGT in the future years, PG&E used $10/kW-yr from the RPS Calculator.

c) **Results**

The resulting short-run costs of capacity (MGCC) are $30.23/kW-year, $29.62/kW-yr, $28.53/kW-yr, $27.63/kW-yr, $27.70/kW-yr and $27.42/kW-yr for 2017 through 2022, respectively. This represents the cost of an existing CCGT's fixed costs above and beyond what it could earn in the energy market. Table 2-7 shows components in deriving short-run costs of capacity for each year from 2017 through 2022.

b. Computing a Levelized MGCC for 2017-2022 and Adjusting by Voltage Level with Line Loss Factors

To calculate levelized MGCC, PG&E first calculated a Net Present Value (NPV) sum of the six years of MGCCs and then converted this NPV to a levelized value using the same discount rate. PG&E used its after-tax Weighted Average Cost of Capital (WACC) of 7.0 percent. The resulting levelized MGCC is $28.64/kW-year, whose calculation is shown in Table 2-8.

To estimate the MGCC at three voltage levels, PG&E began with the levelized MGCC at the transmission level and then grossed that number up by the appropriate demand line loss factor[45] to account for expected line losses. This calculation is similar to how the MEC was developed for each voltage level. Table 2-9 displays PG&E's current demand line loss factors. Table 2-10 shows how line losses were used to estimate MGCCs by voltage level.

c. Planning Reserve Margin

Beginning in June 2006, PG&E and other Load Serving Entities (LSE) were required to meet a 15 percent planning reserve requirement.[46] As a result, the marginal capacity cost of serving a given customer demand level, as calculated in PG&E's revenue

[45] The demand line loss factors are the same as those used in PG&E's TO-13 rate filing at FERC.

[46] See D.04-10-035, Conclusion of Law 4.

allocation model, should include an additional 15 percent amount of capacity that LSEs need to procure to serve that demand level, plus the associated Planning Reserve Margin.

D. Conclusion

The MEC reflects the value of the marginal energy unit to customers, while the MGCC reflects the value of the marginal capacity unit to customers. Economic theory indicates that pricing energy and capacity at the marginal unit cost should result in an efficient allocation among customers of both energy and capacity.

PG&E requests the Commission adopt the generation marginal cost estimates proposed by PG&E in this testimony.

TABLE 2-7
SHORT-RUN COST OF CAPACITY
($/kW-yr)

Line No.	Component	2017	2018	2019	2020	2021	2022
1	Insurance Cost	$8.12	$8.28	$8.44	$8.61	$8.78	$8.96
2	Property Taxes	15.82	16.14	16.46	16.79	17.13	17.47
3	Fixed O&M	20.81	21.22	21.65	22.08	22.52	22.97
4	Going-Forward Fixed Cost of a CC (Sum of Lines 1 Through 3)	$44.75	$45.64	$46.56	$47.49	$48.44	$49.40
5	Energy Gross Margin	-14.52	-16.02	-18.03	-19.85	-20.74	-21.98
6	Net Capacity Cost (Sum of Lines 4 and 5)	$30.23	$29.62	$28.53	$27.63	$27.70	$27.42

TABLE 2-8
CALCULATION OF MGCC[(a)]
($/kW-yr)

Line No.	Year	Residual Capacity Value
1	2017	$30.23
2	2018	29.62
3	2019	28.53
4	2020	27.63
5	2021	27.70
6	2022	27.42
7	PG&E After-Tax WACC	7.0%
8	NPV of 6-Year Sum	136.52
9	MGCC (Levelized Cost for Six Years at 7.0%)	$28.64

(a) See Table 2 6 for the derivation of this value.

TABLE 2-9
T&D
DEMAND LOSS FACTORS

		Percent Loss Factor	Energy Loss Factor	Cumulative Loss Factor	
				Meter to Generation	Generation to Meter
Line No.	Location	From Source Documents	1 / (1 - Percent Loss Factor)	Product of Loss Factors at Each Level	Inverse of Cumulative Loss Factors
1	Generator Bus Bar	0.000%	1.0000	1.0000	1.0000
2	Generation Tie	0.211%	1.0021	1.0021	0.9979
3	HV Transmission	2.061%	1.0210	1.0232	0.9773
4	Low Voltage Transmission	1.946%	1.0198	1.0435	0.9583
5	Primary Distribution Output	2.852%	1.0294	1.0741	0.9310
6	Secondary Distribution	5.651%	1.0599	1.1385	0.8784

Source Documents:

– Transmission losses from May 14, 2010 "Transmission Loss Factors."

– Distribution losses from "Distribution Loss Values for the TO-8 Filing.

TABLE 2-10
CALCULATION OF LEVELIZED MGCC
BY VOLTAGE LEVEL FOR 2017-2022
($/KW-YEAR)

Line No.	Period	Transmission MEC (Based on 2014-2019 Capacity Forecast)	Multiplied by Primary Distribution Demand Loss Factor	Primary Distribution MGCC	Multiplied by Secondary Distribution Demand Loss Factor	Secondary Distribution MGCC
1	2017-2022 Levelized Cost	$28.64	× 1.0294 =	$29.48	× 1.0599 =	$31.25

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

DEFERRABLE TRANSMISSION CAPACITY PROJECTS

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CHAPTER 3
DEFERRABLE TRANSMISSION CAPACITY PROJECTS

A. Introduction

This chapter describes the process Pacific Gas and Electric Company (PG&E) used to identify projects contained in PG&E's 2016 Electric Transmission Grid Expansion Plan that can be deferred if electric demand growth fails to materialize as projected over the 10-year study period. This chapter provides the list of projects from the grid expansion plan that are identified as deferrable using the screening process described below.

Deferrable transmission projects are effectively demand-related marginal transmission investments and are a key input into the calculation of PG&E's marginal transmission capacity cost.[1] On a regular basis, PG&E coordinates with the California Independent System Operator (CAISO) to discuss the status of projects previously approved by the CAISO. During these meetings, PG&E notifies the CAISO of any projects that have been deferred and the reasoning for deferral.

The remainder of this chapter is organized as follows:

- Section B – PG&E's 2016 Electric Transmission Grid Expansion Plan
- Section C – Screening Process
- Section D – Results
- Section E – Conclusion

B. PG&E's 2016 Electric Transmission Grid Expansion Plan

The PG&E transmission grid consists of about 18,500 miles of transmission lines and cables and 200 high voltage substations with nominal voltages of 500, 230, 115, 70 and 60 kilovolts (kV). In accordance with the CAISO's Tariff, Section 24, as well as the business rules set forth in the CAISO Business Practice Manual, PG&E is required to participate in the annual CAISO Transmission Planning Process (TPP). The CAISO's TPP is an annual integrated, open, participatory and transparent process that focuses on ensuring reliable, economically efficient, and nondiscriminatory use of the

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[1] See Exhibit (PG&E-9), Chapter 4 for discussion.

transmission system. The CAISO's TPP is structured into three main phases, which are: (1) development of Unified Planning Assumptions and CAISO Study Plan; (2) performing technical studies for assessment of system reliability and various other purposes; documentation of technical study results and development of transmission proposals; and development of the annual comprehensive transmission plan; and (3) if needed, competitive solicitation to build and own economically and policy-driven transmission projects in board-approved plan.

Development of PG&E's annual transmission system assessment and transmission expansion plan is coordinated within the CAISO's TPP. PG&E is required to participate and submit annually electric transmission facility expansion plans necessary to address identified reliability concerns. These expansion plans identify the electric transmission facilities within the PG&E service territory that are projected to be insufficient pursuant to North American Electric Reliability Corporation, Western Electricity Coordinating Council, and CAISO Planning Standards and Criteria during the 10-year planning horizon. As part of the CAISO TPP, market participants are encouraged to participate and provide comments and input on PG&E's proposed transmission plans.

PG&E's latest transmission expansion plan is documented in the "PG&E 2016 Electric Transmission Grid Expansion Plan" dated March 25, 2016. PG&E's Plan covers the period from 2016 to 2025. It identifies specific transmission expansion upgrades needed in the near-term, 5-year period and in the long-term, 10-year period to address the applicable reliability standards and criteria. The PG&E projects identified in this cycle to meet the reliability, and regulatory obligations were submitted to the CAISO in September 2015 seeking approval. Then as part of the TPP process, the CAISO evaluated the project proposals and developed a Transmission Plan recommending the approval of those projects that were found to be most effective at mitigating the identified transmission problems. The Transmission Plan was then submitted to the CAISO Board for approval. The PG&E projects that were recommended for approval are included in this plan. The CAISO board subsequently approved the various project proposals identified in that plan in March 2016.

In summary, including previously CAISO-approved projects and 10 new project proposals that were submitted into the CAISO's Request Window for approval, there are 124 transmission projects in PG&E's 2015 Electric Transmission Grid Expansion Plan representing an expected capital investment of $4 billion to $5.7 billion depending on final project cost, scope and schedule. PG&E will continue to be in full compliance with all applicable transmission planning criteria and standards. Lastly, the 2016 transmission plan also documents 13 projects that are mainly driven by load forecast, but that with the recent lower load forecasts are no longer needed and which were cancelled by the CAISO as part of its 2015-2015 TPP.

C. Screening Process

PG&E evaluated the 124 projects in its 2016 Electric Transmission Grid Expansion Plan one at a time to determine whether a project could be deferred if electric demand growth *in the area served by the project* failed to materialize as projected over the 10-year study period. The following screening criteria were used:

1. Projects needed to meet regulatory, contractual or safety requirements are non-deferrable.
2. Projects that improve system efficiency, such as those that reduce Local Capacity Adequacy Requirements or cost-effectively reduce customer outage time, are non-deferrable.
3. Projects that address greater than 10 percent capacity deficiency are non-deferrable.

D. Results

Of the 124 projects in PG&E's 2016 Electric Transmission Grid Expansion Plan, 30 projects were found to be deferrable. These 30 projects are listed in Table 3-1 below.

E. Conclusion

PG&E on an annual basis develops its Electric Transmission Grid Expansion Plan. Development of this transmission plan is coordinated in accordance with the business rules set forth in the CAISO Business Practice Manual for the TPP in which PG&E is required to participate. The CAISO's TPP is an annual integrated, open, participatory and transparent process that focuses on ensuring reliable, economically efficient, and nondiscriminatory use of the transmission system. The process allows for the continuing review of the need for identified system facilities during the 10-year planning horizon. If a given facility loading is reduced considerably prior to the implementation date, due to system changes or demand forecasts, then the implementation date of the project may be deferred accordingly. Of the projects developed in PG&E's 2016 Electric Transmission Grid Expansion Plan, 30 projects were found to be deferrable.

The 30 transmission projects found to be deferrable using the process discussed in this chapter are projects driven by demand, and not by regulatory, safety, contractual, efficiency or other reasons listed in the screening criteria in Section C, above. Therefore, these deferrable transmission projects are the marginal investments from which PG&E can estimate the marginal transmission capacity cost.[2]

2 See Exhibit (PG&E-9), Chapter 4 for discussion of the calculation of PG&E's marginal transmission capacity cost.

TABLE 3-1
DEFERRABLE TRANSMISSION CAPACITY PROJECTS

Line No.	Project Title	Cost Range ($)	Targeted In-Service Date	Can Be Deferred by 5-10% Demand Reduction
1	Napa – Tulucay No. 1 60 kV Line Upgrades	5M – 10M	2020	Yes
2	Stone 115 kV Back-tie Reconductor	5M – 10M	2020	Yes
3	Cayucos 70 kV Shunt Capacitor	10M – 20M	2021	Yes
4	Glenn #1 60 kV Reconductoring	5M – 10M	2021	Yes
5	Kearney – Kerman 70 kV Line Reconductor	10M – 20M	2021	Yes
6	Lockheed No.1 115 kV Tap Reconductor	1M – 5M	2021	Yes
7	Los Esteros – Montague 115 kV Substation Equipment Upgrade	0.5M – 1M	2021	Yes
8	Moraga – Castro Valley 230 kV Line Capacity Increase Project	5M – 10M	2021	Yes
9	North Tower 115 kV Looping Project	5M – 10M	2021	Yes
10	Reedley 115/70 kV Transformer Capacity Increase	10M – 15M	2021	Yes
11	Taft – Maricopa 70 kV Line Reconductor	5M – 10M	2021	Yes
12	Vaca – Davis Voltage Conversion Project	80M – 90M	2021	Yes
13	Cascade – Benton 60 kV Line	10M – 20M	2022	Yes
14	Fulton 230/115 kV Transformer	10M – 20M	2022	Yes
15	Metcalf – Piercy & Swift and Newark – Dixon Landing 115 kV Upgrade	40M – 50M	2022	Yes
16	Monta Vista – Los Gatos – Evergreen 60 kV Project	10M – 20M	2022	Yes
17	Mountain View/Whisman – Monta Vista 115 kV Reconductoring	10M – 20M	2022	Yes
18	Pittsburg 230/115 kV Transformer Capacity Increase	10M – 20M	2022	Yes
19	San Mateo – Bair 60 kV Line Reconductor	5M – 10M	2022	Yes
20	Soledad 115/60 kV Transformer Capacity	10M – 20M	2022	Yes
21	Clear Lake 60 kV System Reinforcement	30M – 40M	2023	Yes
22	Cottonwood – Red Bluff No. 2 60 kV Line Project and Red Bluff Area 230/60 kV Substation Project	50M – 60M	2023	Yes
23	Ignacio – Alto 60 kV Line Voltage Conversion	40M – 50M	2023	Yes
24	Natividad Substation Interconnection	10M – 20M	2023	Yes
25	Atlantic – Placer 115 kV Line	80M – 90M	2024	Yes
26	New Bridgeville – Garberville No.2 115 kV Line	80M – 90M	2024	Yes
27	Rio Oso – Atlantic 230 kV Line Project	40M – 50M	2024	Yes
28	Cressey – North Merced 115 kV Line Addition	20M – 30M	2026	Yes
29	South of San Mateo Capacity Increase	80M – 200M	2029	Yes
30	Jefferson – Stanford #2 60 kV Line	30M – 40M	on-hold	Yes

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CHAPTER 4

MARGINAL TRANSMISSION CAPACITY COSTS

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CHAPTER 4
MARGINAL TRANSMISSION CAPACITY COSTS

A. Introduction and Request

This chapter presents Pacific Gas and Electric Company's (PG&E) demand-related marginal transmission capacity cost (MTCC) estimate. PG&E's transmission rates are regulated by the Federal Energy Regulatory Commission. Therefore, the MTCC is not required for rate setting in this proceeding.

Although PG&E's transmission rates are regulated by the Federal Energy Regulatory Commission and set on an embedded cost basis, PG&E requires MTCC values for purposes other than determining electric transmission marginal cost revenues and class allocations of electric transmission revenue requirements for rate setting. In particular, PG&E requires MTCC values for use in marginal cost price floor calculations as required by Schedule E-31, the Distribution Bypass Deferral Rate, and PG&E requests approval of the MTCC for that purpose and for use in other proceedings where MTCC may be required.

The result of PG&E's estimate of MTCC is a value of $11.48 per kilowatt (kW) per year.

The remainder of this chapter is organized as follows:

- Section B – Method
- Section C – Conclusion

B. Method

PG&E estimated a systemwide forward-looking MTCC using the Discounted Total Investment Method (DTIM).[1] The DTIM calculation includes an adjustment for the time value of money and calculates an average investment cost for streams of lumpy[2] investments needed to serve additional loads. MTCC, using the DTIM, is calculated in two basic steps. The first step is to calculate the marginal investment per megawatt (MW) of demand. The second step is to

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[1] The mathematical equation for DTIM is discussed in Appendix A, "Mathematical Formulation of the Discounted Total Investment Method and Alternative Methods to Compute Marginal Distribution Capacity Cost," of this exhibit.

[2] An investment stream is said to be "lumpy" when there is a large year-to-year variation in the size of the investments.

calculate an annualized marginal cost in dollars per MW per year using a Real Economic Carrying Charge (RECC) factor with marginal cost loaders and financial factors.

The first step for application of the DTIM to a marginal capacity cost calculation is the calculation of marginal investment: marginal investment is the present value of deferrable investments divided by the present value of forecasted load growth.[3] The result is the marginal investment per MW. For MTCC in this chapter, the marginal investments are projects in PG&E's 2016 Electric Transmission Grid Expansion Plan identified as deferrable as described in Chapter 3, "Deferrable Transmission Capacity Projects," of this exhibit.[4] The forecasted load growth is from PG&E's Line 09 Peak Forecast MW 1-in-10 recurrence interval used as part of the transmission planning process.[5]

The second step is to annualize the marginal investment: the marginal investment is multiplied by an annualization factor that levelizes the marginal investment in real dollars over its lifetime. The resulting marginal cost reflects the annualized cost of investment as well as other capital costs and annual expenses associated with adding capacity to the transmission system. The annualization factor includes a RECC and marginal cost loaders and financial factors for Operations and Maintenance and Administrative and General expenses, common and general plant, cash working capital and franchise fees and uncollectibles. The development of the RECC and the loaders and financial factors is presented in Chapter 13, "Marginal Cost Loaders and Financial Factors," of this exhibit.

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3 The apparent discounting of load arises from the discounting of incremental cash flows needed to invest in capacity where the discounted cash flows are equal to the application of a marginal cost per unit of capacity (essentially a levelized price) applied to the quantities of incremental load capacity. This discounting of load is discussed further in Appendix A of this exhibit.

4 As described in Chapter 3, "Deferrable Transmission Capacity Projects," of this exhibit, PG&E's 2016 Electric Transmission Grid Expansion Plan was submitted to the California Independent System Operator (CAISO) in accordance with CAISO tariff, Section 3.2.1. The CAISO approved various project proposals identified in that plan in March 2016.

5 The systemwide and geographical Line 09 1-in-10 recurrence interval peak MW demand forecast used to calculate demand growth for the DTIM calculation is taken from the 2015 peak demand forecast incorporated in PG&E's 2016 Electric Transmission Grid Expansion Plan. This forecast was accepted by CAISO for developing a base case load assessment for PG&E's bulk transmission planning.

C. Conclusion

The estimated marginal cost using the DTIM result is a demand-related MTCC in dollars per kW per year of $11.48. PG&E believes that this systemwide MTCC is reasonable and, though not required for ratemaking purposes in this General Rate Case, should be adopted for use by PG&E for purposes including setting marginal cost-based price floors under Schedule E-31 and for other non-ratemaking analyses where MTCC may be needed.

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CHAPTER 5

DISTRIBUTION EXPANSION PLANNING PROCESS AND PROJECTED COSTS

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A. Introduction

This chapter describes the planning process that Pacific Gas and Electric Company (PG&E) uses to develop: (1) area specific load forecasts; and (2) 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. This chapter addresses the planning process for the primary distribution system.[1]

The purpose of the planning process is to provide sufficient substation and feeder 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 strategy 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).

However, while the basic distribution planning strategy has remained generally-consistent over time, in 2008, PG&E revised how it rates distribution

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[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.

substation transformers. This change is discussed in Section D, below. In Phase I of its 2017 GRC, PG&E proposes that the California Public Utilities Commission (Commission) adopt criteria for emergency deficiencies in urban and suburban area of 10 megawatts (MW). Phase I projects that address 10 MW deficiencies is discussed in Section F.

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 2017 GRC Phase I Testimony
- Section G – Non-Marginality of Distribution Operations and Maintenance (O&M) and Replacement Costs
- Section H – Distribution Capacity Planning and Distributed Generation (DG)
- Section I – Results and Conclusion

The basic elements listed above are the same as those presented during Phase II of PG&E's 2014 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). For many years PG&E forecast distribution expansion based on DPAs and analyzed load and capacity at the DPA level.

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 no ties to substations outside the area. Although ideal DPAs are not encountered in practice, DPAs are defined as nearly as practicable to that ideal. Currently, there are 245 DPAs in PG&E's service territory. A significant change in the distribution load growth methodology occurred in 2013. The current process forecasts at the bank and feeder level; the DPA no longer has significance in the planning or forecasting process. 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 Distribution Planning workgroups.

C. Load Forecasting

The latest forecasting methodology represents a significant change in the process since the 2014 GRC filing. Previously, the forecast was completed at the DPA level and the forecast growth allocated to the banks and feeders within the designated DPA. The current process forecasts load growth at the bank and feeder level, aggregated to the DPA level. PG&E's new forecasting process and additional information about the new program are described below.

1. Overview

PG&E's distribution engineers annually forecast the magnitude and location of load projections to ensure that adequate distribution capacity is available in time to meet demand in each area. The need to forecast future loads and assign those loads to specific facilities is intended to allow adequate time to address capacity deficiencies where needed in order to prevent overloading of facilities. While PG&E's planning process is designed to minimize equipment overloads, transformer, feeder or component overloads can occur due to: (1) actual growth to forecast differences; (2) metering device inaccuracies; or (3) weather conditions which exceed PG&E's design 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—based on new known-loads and generation, or firm capacity agreements—before forecasting future loads.

PG&E utilizes 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 LoadSEER Geographic Information System (GIS), in which each application uses different methodologies to develop a 10-year forecast.

2. Load Forecasting Tool – LoadSEER

The LoadSEER program is designed to allow distribution planning engineers to forecast 10 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 economic factors. The historical peak loads are also weather-normalized during the regression analysis and the final forecast shows the load normalized to a 1 in 2 year (50 percent quartile) and 1 in 10 year (90 percent quartile) weather event. Each bank and associated feeder is assigned to a weather station to be used for the weather normalization.

The LoadSEER GIS methodology involves a spatial forecasting program that utilizes proprietary algorithms and satellite imagery to score each acre of PG&E's service territory for the likelihood of increased load. The LoadSEER GIS model also includes 20 years of historical aerial imagery of land use to determine the historical type of expansion that has occurred in an area and to facilitate the scoring of each acre. The LoadSEER GIS spatial model is further enhanced by utilizing a megawatt-hour model that is weather-normalized and also includes economic variables. The algorithm used by LoadSEER GIS evaluates and scores each acre based on the likelihood of increased load by customer class (domestic, commercial, industrial, or agricultural). The program then allocates the California Energy Commission's (CEC) annual simultaneous distribution system peak load growth projections for each customer class to each parcel and feeder by identifying which feeder is in the closest proximity to the acre.

The LoadSEER program has the ability to 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 LoadSEER's customer class hourly load shapes. This process is completed for all circuits within PG&E's service territory, for each of the future 10 years.

a. Input Data

In preparation for the annual forecasting process, customer class counts and kilowatt-hour (kWh) consumption using the current year's July data point for each feeder is gathered and populated into the program. In addition, the previous 12 months of hourly temperature data and the current year's summer peak load for each feeder and bank is imported, including the actual peak time and date for those devices which have Supervisory Control and Data Acquisition (SCADA) information. All specific data points are applied to the peak load information for each feeder and bank.

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

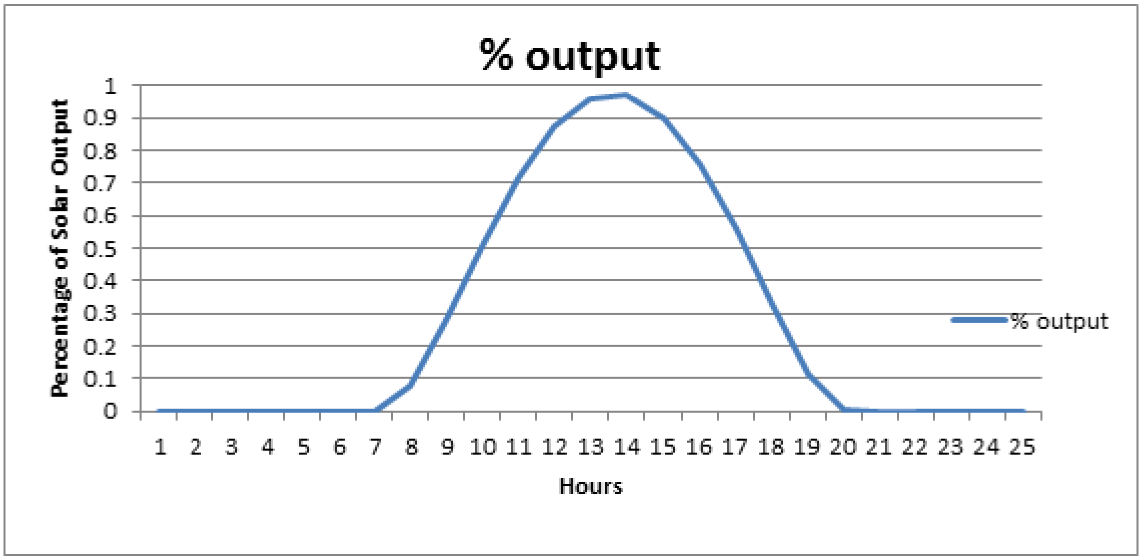
1) Load Adjustments

Load adjustments are added to the annual bank and feeder peaks to account for the output of the single largest DG connected to the feeder or bank during the time of the feeder or bank's peak hour. This adjustment is done to ensure that the distribution facilities are adequately sized to to serve all customer load should the largest DG system not be available during the time of peak loading.

The loss of the largest single DG system is considered as the only N-1 scenerio 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 and 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 one water source should be utilized to determine the amount of load adjustment added to the annual peak demand.

For photovoltaic (PV) DG systems, only those locations 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 feeder and bank peaks (these may be different hours) 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 load shape 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 between the months of June and September in PG&E's service territory.

FIGURE 5-1
PV HOURLY OUTPUT CURVE



July Solar Output shape																									
% output	0	0	0	0	0	0	0%	8%	28%	51%	72%	87%	96%	97%	90%	76%	56%	33%	12%	1%	0	0	0	0	0
Time	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24

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 – SSE; where the error in the response (SSTO) is the total sum of squares in the response about the mean; and the error in the regression (SSE) is the sum of squares in the response about the regression line. 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 you add 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 Reliability score which is intended as a measure of 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 Model Reliability is poor, and its 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 Reliability score.

The LoadSEER GIS model also produces a similar adjusted R-squared score for the kWh consumption forecasting along with the probability of new load being added.

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 help alert to a possible error in forecasting data, or significant change in future loading. These conflicting forecasts can reflect downturns in economic indicators, or an area reaching full buildout following a period of high growth, etc. Finally, the LoadSEER FIT program also has an option that allows a blend of the LoadSEER FIT and LoadSEER GIS forecasts to provide a resultant forecast which can be used to evaluate system deficiencies.

All bank and feeder 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 feeder does not include future growth, but the regression forecasts have a reasonable (>0.5) 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 feeder or bank and the regression forecast has no- or a 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.

D. Capability of Facilities

LoadSEER contains the normal and emergency capability ratings of each distribution bank and feeder in the system. These capabilities are validated for all substations and feeders as part of the annual load forecasting process.

Once the load forecast is complete, Distribution Engineers review the load-carrying capability of the various components of the existing distribution system as part of the planning process.

The most significant type of load growth-related electric distribution capacity expenditure is substation projects (e.g., adding new substations, new substation banks, replacing smaller substation banks with higher capacity units, and adding new circuits, etc.). This section focuses on the capability of facilities from a substation perspective.

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 feeder has a capability rating for both normal and emergency operating conditions. PG&E assigns capability ratings for distribution substation transformers using the nameplate rating in Megavolt Amperes, while assuming a 99 percent power factor to determine the MW rating.

E. Distribution Expansion Plans and Costs

After the load-carrying capability for a bank or feeder has been determined (as described in Section D) the next task is to determine when forecast annual peak demands (as explained 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 feeder 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: (1) not be loaded beyond their emergency capabilities; and (2) be returned to the normal capability ratings in 24 hours or less.

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

Whether considering normal or emergency operating conditions, it is essential to have a working knowledge of facilities in order 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 5-year planning process. For each bank and feeder, distribution engineers provided current information on existing capacity, forecasted load growth, and the expected distribution facility installations related to load growth for each year from 2015-2019. Because construction lead time for some facilities is several years, the 5-year planning horizon ensures that facilities are completed on time to meet peak demand. The information developed by distribution engineers on 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 workpapers that support this chapter. This expansion plan and cost information, and the load forecast data described in Section C, provides the basis, along with division-level accounting data on small projects, for the calculation of area-specific distribution marginal costs as described in Exhibit (PG&E-9), Chapter 6, "Marginal Distribution Capacity Costs." The cost information provided is based on the information PG&E included in the 2017 GRC Phase I testimony.[2]

F. Emergency Capacity 2017 GRC Phase I Testimony

In Phase I of its 2017 GRC Application (A.)15-09-001, PG&E identified emergency deficiency projects in urban and suburban areas for emergency deficiencies at 10 MW or greater. PG&E believes it is appropriate to have adequate levels of emergency capacity in urban and suburban areas.

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[2] See A.15-09-001, 2017 GRC Phase I, Exhibit (PG&E-4), Chapter 13, "Electric Distribution Capacity," and associated workpapers.

Using these criteria, PG&E included four transformer emergency deficiency replacement projects in the years between 2017 and 2019.

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

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

With respect to O&M costs, Commission General Order (GO) 165—which regulates utility inspection and maintenance of certain distribution facilities—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, consider, for example, the life of a distribution pole—which is generally considered to be on the order of 40 years. If a pole is 20 years old, it will, on average, require replacement in about 20 years. The timing and cost of replacement may be affected by environmental factors in its specific location, but are largely unaffected by changes in consumer demand for electricity so 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.

H. Distribution Capacity Planning and DG

PG&E supports the continued and expanded integration of Distributed Energy Resources (DER) onto PG&E's distribution grid, while maintaining grid resiliency, safety, reliability, and affordability and honoring customers' choices for access to clean, affordable energy. DERs included: (1) Distributed Renewable Generation; (2) Energy Storage (ES); (3) Energy Efficiency (EE); (4) Demand Response (DR); and (5) Electric Vehicles.

Load impacts from existing interconnected small DG, from historical DR and from historical EE measures are embedded in the historic observed peak loads. This historic data, inclusive of the impacts of existing DERs, is used to determine the level of temperature-normalized historic peak demand in the LoadSEER geospatial forecasts. To the extent that DERs are incorporated by PG&E and the CEC's adopted California Energy Demand base case peak load forecast, LoadSEER geospatial forecasts incorporate projected future load impacts due to DG, DR, EE, non-event DR (e.g., time-of-use rates and permanent load shifting), and event-based DR (e.g., peak day pricing and SmartRate™). Incorporating DERs into the underlying load growth projections ensures they are reflected in the need for capacity additions. Based on the distribution load growth forecasting methodology described above, a number of distribution projects that would have otherwise been needed, have been re-scheduled or avoided, based on EE, DR, and DG load impacts incorporated into the historical data and load growth projections used in the distribution planning process.

Completion of the load growth forecasting process results in identification of capacity deficiencies and the required system expansion projects necessary 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 (outlined in PG&E's Utility Standard: TD-2058S, "Evaluating Distributed Energy Resource Alternative for Capacity and Reliability Improvements") to determine cost, as well as capacity and reliability benefits for each alternative studied. Over the last few years, PG&E has successfully used Targeted Demand-Side Management to reduce peak loading, thereby re-scheduling expansion projects to a future date. In addition, and separate from the GRC, in 2014 PG&E issued an ES Request for Offers that identified five substations to be evaluated for ES versus capital expansion from both an operational- and cost perspective.

DER forecast capability is expected to evolve with the enhancements to LoadSEER as part of the Electric Program Investment Charge (EPIC) II, Project 23: "Integrate Distributed Energy Resources in Utility Planning Tools." Completion of the EPIC project will provide capability for the annual load forecasting and planning processes to include both load and DER evaluations based on the latest system conditions and forecast available.

I. Results and Conclusion

This chapter has described the planning process that PG&E uses to forecast area-specific electric loads and distribution plans, both of which support PG&E marginal distribution capacity costs as described in Exhibit (PG&E-9), Chapter 6. The workpapers that support this chapter include the load forecasts for PG&E's

DPAs and the load growth-related investments resulting from PG&E’s distribution planning process.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

MARGINAL DISTRIBUTION CAPACITY COSTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6
MARGINAL DISTRIBUTION CAPACITY COSTS

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6
MARGINAL DISTRIBUTION CAPACITY COSTS

A. Introduction

This chapter presents the results of Pacific Gas and Electric Company's (PG&E or the Company) estimated demand-related marginal primary and secondary distribution capacity costs. This chapter includes a summary of the marginal cost estimates for PG&E's 19 operating divisions,[1] a discussion of the Discounted Total Investment Method (DTIM) that is the basis of PG&E's Marginal Distribution Capacity Cost (MDCC) proposal and additional background about DTIM and alternate MDCC methodologies that have been used in prior PG&E General Rate Case (GRC) proposals.

PG&E is requesting that the California Public Utilities Commission (CPUC or Commission) approve PG&E's marginal cost methodology and to find PG&E's MDCC estimates reasonable. These MDCC values are used for the following: (1) for marginal cost revenue calculations and rate design in this case; (2) for the purpose of establishing costs where needed for customer-specific contract analysis including as required by Schedule E-31(Distribution Bypass Deferral Rate) and for analysis of contribution to margin for customers taking service under Schedule EDR (Economic Development Rate); (3) for cost-effectiveness analysis of Customer Energy Efficiency (CEE) and Demand-Side Management (DSM) programs and distributed resource evaluation; and (4) for use in avoided cost modeling in other Commission proceedings.

MDCC results for each division are shown in Table 6-1. The primary and secondary system MDCC averages are shown for informational purposes only.[2] For primary distribution, PG&E measures capacity at substations using peak

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1 Part way through the time horizon during which the marginal cost data were developed for PG&E's 2014 GRC Phase II, the former North Coast operating division was split into the Humboldt and Sonoma operating divisions. Now, for this 2017 GRC Phase II marginal cost showing, all of the data across the entire relevant time horizon reflects the split into the Humboldt and Sonoma operating divisions. Thus, in this showing, PG&E references the current 19 operating divisions.

2 Marginal primary distribution capacity cost by Distribution Planning Area (DPA) is shown in the workpapers.

capacity allocation factors (PCAF).[3] For secondary distribution and primary distribution for new business, PG&E measures peak capacity at the final line transformer (FLT).[4] Therefore, primary distribution marginal costs are shown in dollars per PCAF-kilowatt (kW) per year and primary distribution for new business and secondary distribution marginal costs are shown in dollars per FLT-kW per year.

TABLE 6-1
MARGINAL DEMAND-RELATED PRIMARY AND SECONDARY DISTRIBUTION CAPACITY COSTS BY DIVISION AND SYSTEM AVERAGE

Line No.	Division	Primary Distribution $/PCAF kW	New Business on Primary Distribution $/FLT kW	Secondary Distribution $/FLT kW
1	Central Coast	$69.09	$14.53	$1.04
2	De Anza	$35.65	$19.66	$1.01
3	Diablo	$17.78	$23.20	$1.56
4	East Bay	$19.99	$18.07	$0.88
5	Fresno	$39.52	$15.81	$1.36
6	Humboldt	$73.97	$14.20	$1.12
7	Kern	$34.07	$16.08	$1.23
8	Los Padres	$56.49	$14.41	$1.06
9	Mission	$13.63	$16.37	$0.97
10	North Bay	$29.42	$14.62	$1.75
11	North Valley	$53.40	$19.23	$1.26
12	Peninsula	$31.79	$14.02	$1.06
13	Sacramento	$40.91	$16.49	$1.22
14	San Francisco	$40.41	$19.69	$1.52
15	San Jose	$40.12	$17.45	$1.16
16	Sierra	$30.65	$20.07	$1.25
17	Sonoma	$121.98	$16.65	$1.28
18	Stockton	$33.36	$15.13	$1.34
19	Yosemite	$60.18	$15.63	$1.56
20	System	$39.43	$16.42	$1.25

The above MDCC results are calculated using the DTIM. In general, using the DTIM to estimate MDCC values is done in two steps. First, the present values of capacity-related incremental investments are divided by the present values of incremental capacity additions yielding values for incremental investment costs per unit of capacity. Then, second, the incremental investment costs per unit of capacity are converted to an annualized marginal cost per unit

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3 See Exhibit (PG&E-9), Chapter 10 for definition of PCAF.

4 See Exhibit (PG&E-9), Chapter 11 for discussion of FLT loads.

of capacity by applying a Real Economic Carrying Charge (RECC) factor and appropriate loadings. The DTIM is described in this chapter, below.[5,6]

PG&E requests that the above MDCC estimates be found reasonable and that the Commission approve the DTIM as a reasonable method for estimating these MDCC values.

The remainder of this chapter is organized as follows:

- Section B – Methodology
- Section C – Background
- Section D – Conclusion

B. Methodology

This section discusses the methodology PG&E used for developing MDCC estimates and changes the Company has made to its application of this methodology for estimating MDCC values subsequent to PG&E's 2014 GRC Phase II MDCC proposal.

PG&E's transmission and distribution (T&D) marginal cost proposals in this case are appropriately based on forecasts of investments and corresponding additions of capacity and include an adjustment for the time value of money using the DTIM.[7] The DTIM, while incorporating the time value of money, effectively calculates an average investment cost for streams of lumpy[8] capacity investments needed to serve additional T&D demands.

From a physical perspective, the distribution system is composed of two parts, based on voltage level: (1) primary; and (2) secondary distribution.

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5 See Exhibit (PG&E-9), Chapter 1 for a general description of DTIM.

6 See Exhibit (PG&E-9), Appendix A for the mathematical formulations for: DTIM; Total Investment Method (TIM); and National Economic Research Associates' (NERA) Regression Method (RM).

7 The DTIM is essentially the World Bank's Average Incremental Cost (AIC) method, annualized using a RECC factor. The AIC method is discussed in a 1977 World Bank staff paper, "Alternative Concepts of Marginal Cost for Public Utility Pricing: Problems of Application in the Water Supply Sector," World Bank Staff Working Paper No. 259, May 1977. The AIC method is a time-value weighted AIC addressing the capital indivisibility (or "lumpiness") problem faced in marginal cost estimation for public utilities. Although the World Bank staff was addressing the water supply and sewerage field, the capital indivisibility problem facing water and sewage utilities also affects other public utilities such as electric, gas and telecommunications companies.

8 An investment stream is said to be "lumpy" when there is a large year-to-year variation in the size of the investments.

The primary distribution system consists of substations and feeders at voltages operating at less than 50 kilovolts (kV). The secondary distribution system operates at less than 4 kV and consists of FLTs and distribution facilities on the customer side of the FLTs. Marginal capacity costs are estimated separately for primary and secondary distribution costs.[9]

For marginal cost estimation, it is useful to classify distribution investments by cause of the plant additions. The major causes of distribution plant investment are summarized in the Table 6-2, below.

TABLE 6-2
DISTRIBUTION PLANT ADDITION TYPES, INVESTMENT CAUSES, AND CLASSIFICATIONS FOR MARGINAL DISTRIBUTION COSTS

Line No.	Distribution Plant Addition Type	Investment Cause	Classification for Marginal Distribution Costs
1	Distribution Reinforcements	Increased demand (i.e., distribution capacity increases)	Capacity growth-related; included in MDCC.
2	Distribution Line Extensions	Provide access and capacity for new customers	Capacity growth-related; included in MDCC
3	Distribution Access Equipment (transformers, secondary and service conductors, and meters)	Specifically to connect new customers	Not capacity growth-related; included in Marginal Customer Access Costs (MCAC)
4	Other Distribution Investments	Not capacity-related	Not capacity growth-related; excluded from marginal distribution costs

In brief, the first two types of investments are capacity additions made to meet demand growth. Distribution reinforcement investments provide capacity to meet demand growth on the existing system and distribution investments for primary line extensions provide access and the associated capacity for new demand due to the addition of new customers. The latter two investment types are not made to meet capacity demand growth. Distribution investments directly identifiable with individual customers provide connectivity for new customers and vary primarily with the number of customers rather than demand on the system, while investments for replacements and relocations are made for reasons other than demand or customer growth. For example, shared distribution facilities

9 See Exhibit (PG&E-9), Chapter 5 for additional description of the voltage distinction for PG&E’s primary and secondary distribution system.

must be replaced regardless of changes in demand and are predominantly driven by time.[10] All of these types of investments can be either primary or secondary distribution.

1. Methodology for This Proposal

PG&E's proposed MDCC values are based only on the investments for capacity additions needed to meet demand growth (the first two types of investments described above). PG&E estimates MDCC values for three subcomponents: (1) marginal primary distribution capacity costs; (2) marginal primary distribution capacity costs for new business; and (3) marginal secondary distribution capacity costs. For the first sub-component, the MDCC estimates are for capacity-related primary distribution plant additions that are generally capacity additions to meet demand growth at distribution substations and on mainline (primary) distribution feeders, and include demand growth-related upstream capacity investments for new line extensions. For the second subcomponent, the MDCC estimates are for plant additions to extend the primary distribution system providing capacity to serve the demand of new customers. For the third subcomponent, the MDCC estimates are for the capacity growth-related secondary distribution system costs. While secondary distribution costs are generally composed of FLTs, secondary conductor, service conductor (service drops) and meters, only the secondary distribution capacity investments made to address demand growth on the existing system sometime after customers have been connected to the distribution system are captured in MDCC, consistent with PG&E's current

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10 For example, wooden distribution poles are generally unaffected by demand; rather, over time they are affected by weather and mechanical stress. On occasion, poles are replaced because of demand-related capital investment where larger poles are required to support larger, higher capacity distribution wires or line transformers. In such cases, demand growth-related pole replacements are properly included in MDCCs.

adopted methodology. These investments consist of demand growth-related capacity investments affecting FLTs and secondary conductor.[11]

Finally, in this proceeding, PG&E continues to differentiate its marginal distribution costs by area. The Commission has indicated that marginal costs should "reflect geographic differences where significant."[12] PG&E continues to observe a wide variation in the marginal cost of distribution capacity among the more than 240 DPAs that comprise its electric system. Accordingly, as noted previously, PG&E continues to estimate marginal costs by DPA, and then to aggregate those costs into PG&E's 19 operating divisions to determine the marginal costs presented in this proceeding.

Using the DTIM, marginal investment for large primary distribution projects[13] is calculated by dividing the present value of forecasted investments (in dollars) to meet demand growth by the present value of forecasted capacity growth (in kW). The result is the marginal investment per kW of capacity. The forecasted investment for large projects and forecasted capacity growth from 2015 through 2020 are provided by DPA by PG&E's Distribution System Planning Department.[14,15] These large projects generally cause marginal cost "lumpiness" over both geographic and time dimensions.

The marginal investments for small projects for primary and secondary distribution and for new business on primary distribution previously were

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11 Service conductors and meters, and *newly* installed FLTs and secondary conductor associated with new connection jobs, are secondary distribution equipment that provide customer access directly identifiable with particular customers. Accordingly, these costs are captured in marginal customer access costs through the new connection component of the Rental method and of the New Customer Only method, discussed in Exhibit (PG&E-9), Chapter 7.

12 See Exhibit (PG&E-9), Chapter 1 for discussion.

13 Examples include installing additional banks and feeders at substations to expand distribution capacity, reinforcing or upgrading existing feeders, and replacing existing banks to increase substation capacity.

14 See Exhibit (PG&E-9), Chapter 5 for discussion of: forecasted investments; forecasted capacity loadings; and forecasting methodology.

15 In addition to the costs excluded from marginal cost calculations listed in Exhibit (PG&E-9), Chapter 5, PG&E also excludes projects that address the cap of 6,000 customers per feeder that are caused by a PG&E design change and not load growth.

calculated differently from the marginal investments for large projects. In prior recent marginal costs showings, PG&E did not produce 5-year forecasts for these smaller projects.[16] However, in PG&E's 2017 GRC Phase I (Application 15-09-001), PG&E now produces a 5-year forecast for these smaller investments (also known as "annuals," representing the sum of numerous small projects). As previously, PG&E relies on three years of recorded data to provide information about expected spending by asset classes such that the portion of those investments that should be considered marginal can be determined Now having five years of forecasted investments for new business projects on primary distribution and for demand growth-related secondary distribution investments, PG&E is applying the DTIM to these investments for fully forward-looking marginal costs by operating division, consistent with the fully forward-looking marginal costs by DPA for primary distribution load growth-related projects over $1 million. Previously, for these numerous small capacity investments for new business and for secondary demand growth, for each division, PG&E calculated the annual average investments using three years of recorded and two years of forecast data, and then divided by the expected annual average total capacity growth related to investments in projects under $1 million.

The calculated marginal investments per kW—for large primary distribution projects over $1 million, and now for investments for new business on primary distribution and for load-growth related investments on secondary distribution, where marginal investment is calculated using the DTIM—are annualized using the RECC factor. To the annualized marginal investments are added other expenses related to the addition of capacity to the distribution system using marginal cost loaders. These loaders include Operations and Maintenance (O&M) expenses, Administrative and General

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16 Most growth-related secondary distribution investments come about because of customer notifications for connecting new customers to the distribution system (which are captured in marginal customer access costs) or for numerous small projects to correct secondary voltage issues related to increased demand on the existing system. Primary distribution investments under $1 million are similarly driven by customer notifications for the purpose of extending the primary distribution system to serve new customer demands or for small projects to correct voltage issues.

expenses for the added O&M, common and general plant expenses, cash working capital expenses, and franchise fees and uncollectibles.[17]

2. Changes From Prior Proposal

As discussed above, where PG&E had previously calculated 5-year annual investments by operating division for projects for new business on primary distribution and for load growth-related secondary distribution projects, and taking the ratios of those 5-year annual average investments to the 5-year average annual load growth as estimates for incremental investments (that were subsequently annualized to marginal costs by application of a RECC and other appropriate loaders and financial factors), PG&E is now using a full five years of forecasted investments for new business on primary distribution and for demand growth-related investments on secondary distribution and is applying the DTIM in the same manner as PG&E has been doing for the demand growth-related primary distribution capacity investments for projects over $1 million. Thus PG&E is estimating each of the three sub-components (demand growth-related capacity projects over $1 million, projects for new business on primary distribution, and demand growth-related capacity projects on secondary distribution) with consistent application of DTIM and is estimating fully forward-looking MDCCs for all three sub-components of MDCC.

PG&E's proposal to estimate MDCC values using the DTIM is a significant change from prior adopted methodologies. Those prior adopted methodologies are discussed in Section C, below.

C. Background

This section presents additional background about methodologies that historically have been used by PG&E for estimating MDCC values prior to its introduction of DTIM in its 1999 GRC.

Prior to the 1993 GRC, PG&E estimated T&D costs by conducting a regression analysis—relying on 10 years of historical and five years of forecast accounting, budget and capacity loading data—resulting in a revenue requirement for the annual average investment. However, such heavy reliance

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17 See Exhibit (PG&E-9), Chapter 13 for description of the development of these marginal cost loaders and the RECC financial factor.

on historical accounting data, representing investments that have already occurred, has limited value when used as a basis for forecasting. These limitations include an inability to capture such external factors as the rate of technological advancements, changes in land values, or internal factors, such as changes in the Company's budgeting or planning practices or new external regulatory requirements for infrastructure improvements. By the early 1990s, PG&E found that the Regression Method (RM) had serious shortcoming when used for estimating area-specific T&D costs, particularly given the large, infrequent nature of investments in each of its T&D planning areas. Marginal costs of these local investments are higher when the size of the investment is large or the investment is expected to occur in the near future. Marginal costs are lower when the size of the investment is smaller or the investment is expected to occur further into the future. The RM attempts to smooth these inherently lumpy additions and cannot meaningfully reflect the timing of future investments in marginal cost estimates.

In contrast, the DTIM and Present Worth Method (PWM), first adopted by the CPUC in PG&E's 1993 GRC Phase II, allow the effects of investment timing and magnitude to be reflected in marginal cost estimates. The DTIM and the PWM do so by better characterizing the real demand growth-related investment alternatives facing a utility with an obligation to serve by calculating the opportunity costs associated with the timing of future investments (or, specifically, with accelerations or deferrals of required future investments for the PWM), rather than merely using an annualized average incremental investment. The DTIM and the PWM are also superior because they place more emphasis on forward-looking data and capture the timing and lumpiness inherent in planned T&D investments. This advantage is particularly important in estimating marginal costs for local planning areas. Thus, both the DTIM and the PWM better embody two key principles the CPUC endorsed in PG&E's 1993 GRC Phase II—that marginal costs should be forward-looking and causally linked to a change in demand, and that they should reflect the timing and magnitude of future investments.[18]

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[18] See D.92-12-057, mimeo, pp. 235-236.

The DTIM is related to the TIM, which was adopted by the CPUC for gas transmission and storage.[19] Decision (D.) 92-12-058 describes the DTIM as follows:

> The Discounted Total Investment Method computes a marginal unit cost by dividing the present value of the planning period's investment by [the present value of][20] the total load growth. A present value is used in the numerator to give additions further into the future less weight than investments in earlier time periods. The marginal unit cost is then annualized using an RECC factor (D.92-12-058, mimeo, p. 33).

The Commission has traditionally relied upon the RM[21] for T&D marginal cost estimation. However, by the early 1990s it became clear to the Commission that the RM was inadequate to deal with lumpy investments. The Commission reviewed this issue in D.92-12-057 (PG&E's 1993 GRC Phase II proceeding) for PG&E's electric T&D marginal costs, as well as in D.92-12-058 (the gas long-run marginal cost proceeding) on a statewide basis for gas T&D marginal costs. Of the four incremental methodologies for estimating T&D marginal costs discussed in D.92-12-058—RM,TIM , DTIM and PWM—only the PWM and the DTIM are sensitive to the timing of lumpy investments. In D.92-12-057, the Commission adopted timing-sensitive and

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[19] See D.92-12-058, mimeo, p. 34.

[20] In the original California description of the DTIM, the loads—really incremental units of capacity—in the denominator were not discounted. The phrase "…the present value of…" is added to correct the description of the DTIM reflecting later thinking as to the proper calculation of marginal costs using this methodology. The denominator, like the numerator, should be discounted. See Appendix B, "Mathematical Formulation of the Discounted Total Investment Method and Alternative Methods to Compute Marginal Distribution Capacity Cost" for a mathematical demonstration as to why it is proper to discount incremental units of capacity in the denominator.

[21] The RM is a marginal costs estimation method developed by NERA Economic Consulting. 15 years of cumulative demand-related distribution capacity investments are regressed on 15 years of cumulative capacity growth, where the 15 years of cumulative data consist of 10 years of recorded and five years of forecast data for demand growth-related capacity investments and capacity growth. The resultant slope of the line from performing a least squares regression is the marginal cost to which a RECC is applied, resulting in a levelized annual marginal cost in dollars per kW per year.

location-specific electric T&D marginal costs, based on the PWM,[22] as proposed by PG&E—partially in response to the desire for more accurate marginal costs for use in resource planning. In that decision, the Commission found:

> It is reasonable that marginal cost components be based on the design and operation of PG&E's system, accurately signal the cost of providing electrical service, be forward-looking, capture the timing and magnitude of future investments, reflect geographic differences where significant,…and finally, provide consistent signals in the evaluation of supply and demand resources for planning purposes. (D.92-12-058, FOF 152, mimeo, p. 291).

In the same month, on the gas side, the CPUC adopted the RM for *gas* distribution but the TIM for *gas* transmission and storage in D.92-12-058. The Commission rejected the RM[23] for gas transmission because of the increased lumpiness of transmission relative to distribution.[24] In D.95-12-053 (PG&E's 1995 Biennial Costa Allocation Proceeding (BCAP) decision), the Commission stated:

> [W]e do see merit in exploring the idea of incorporating the time value of money in the calculation of capital-related marginal costs. We direct PG&E in its next BCAP filing to provide a scenario that incorporates a discounted total investment method to estimate the marginal cost of capital investments. (D.95-12-053, mimeo, p. 37.)

Clearly, the Commission has considered "asset lumpiness" an important factor in marginal cost estimation. PG&E believes that either the DTIM or the PWM are superior to the RM (or the TIM) as an estimator of marginal costs—where, as here, asset lumpiness is significant—because only the former

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22 The PWM calculates the present value of planned investments over a planning horizon and calculates a second present value for those same investments, but assuming that the investments all will be deferred one year. The difference in these two present values is divided by the average expected capacity growth for the planning horizon resulting in a marginal investment. The marginal investment is then annualized using an RECC factor (or similar Capital Recovery Factor (CRF)) and appropriate marginal cost loadings.

23 In D.92-12-058, the CPUC also rejected a replacement cost new (RCN)-based methodology for gas transmission marginal cost.

24 The lumpiness of distribution investments depends upon the geographic scale. For a large utility such as PG&E, distribution investments can be relatively smooth on a systemwide total basis. Regression can work well in such cases. However, the RM approach can mask cost differences that are quite important on a local level, especially for dealing with un-economic bypass or for integrated resource planning that considers: both supply- and demand-side alternatives; cost-effectiveness analysis of CEE and DSM programs and distributed resource evaluation.

methods take into account the time value of money. While PG&E believes that either the DTIM or the PWM are superior to the RM or the TIM, PG&E, starting in its 1999 GRC, introduced the DTIM as its proposed methodology for MDCC calculations in place of the PWM.[25] PG&E is again proposing the DTIM in this proceeding. The advantages of the DTIM approach over other methods are discussed below.

1. TIM

The fundamental premise underlying the TIM is that capacity can be added in very small increments. The first step in the TIM is to calculate the marginal investment per kW by dividing cumulative demand growth-related investment for the selected time horizon by cumulative capacity growth for that same time horizon. In the application of the TIM, the time horizon has been 15 years, of which 10 are historical and 5 are forecast. The second step of the TIM is to annualize the marginal investment by multiplying by a RECC factor and applying marginal cost loadings. The TIM, as a marginal cost method, is not sensitive to the timing of the forward-looking forecast capacity additions. The TIM includes no discounting for the time value of money, so whether a forecast large capacity addition occurs in Year 5 or Year 1 in the forecast portion of the time horizon, the impact on the marginal cost estimate is the same. In fact, if all investments in the time horizon are moved to any single year, the result is the same as if the investments were spread across the time horizon. Additionally, the predominance of historical data does not provide a strong causal link between a change in future demand and the calculation of

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[25] In PG&E’s 1996 GRC Phase II (D.97-03-017), the CPUC returned to the RM from PG&E’s PWM adopted in its 1993 GRC Phase II (D.92-12-057), citing volatility concerns when using the PWM and concerns with PG&E’s geographically-differentiated marginal T&D costs. PG&E disputes the notion that the RM produces marginal costs that are less volatile than methods that better address the lumpiness and investment timing issue—like the DTIM—that include the time value of money. The Commission did leave the door open to further reconsideration once PG&E had eliminated concerns about ad hoc distribution planning by area. Although PG&E fully addressed those distribution planning concerns in the 1999 GRC, that proceeding was suspended due to the California energy crisis, and the 2003, 2007, 2011, and 2014 GRC Phase II proceedings were all settled.

marginal costs.[26] In particular, primary distribution capacity additions that can be identified and forecast by distribution planners provide a superior basis for marginal costs. Marginal costs should signal the amount of surplus capacity and the timing of new additions. As capacity tightens, the marginal cost should increase as the need for additional capacity moves closer in time. The TIM does not adhere to this fundamental marginal cost principle; thus, it is inferior to the DTIM, which does adhere to this principle by including the time value of money.

2. RM

Like the TIM, the underlying premise of the RM is that capacity can be added in very small increments, and, similarly, the RM calculates a marginal investment that is then annualized in the same manner as the TIM marginal investment. However, the RM marginal investment is estimated as the slope of a line determined by regressing 15 years of cumulative demand-growth related investments by 15 years of cumulative capacity growth using simple (ordinary least squares) regression. Like the TIM, the RM uses 10 years of historical data and 5 years of forecast data. In its implementation, the dependent variable is *cumulative* annual incremental demand growth-related capacity investments and the independent variable, on which it is regressed, is *cumulative* annual capacity growth. The effect of regressing cumulative incremental capacity investments on cumulative capacity growth is a smoothing of the effects of any “lumpiness” in the data, and because the RM uses cumulative data, the 10 years of historical data dampens the impact of any expected lumpiness in the forecast data.

Like the TIM, the RM relies extensively on historical accounting data to the detriment of estimating forward-looking costs: the forecast capacity investment plan may properly vary considerably from the historical trend, especially at a local level. The RM cannot adequately estimate forward-looking marginal costs when investment and load forecasts vary significantly from past trends. Past investment decisions have limited value for

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26 This is not to say the historical data should be disregarded: historical data is useful to the extent they help to predict the future and may be a proper source for estimating future capacity additions for the many small (under $1 million) load growth-related capacity projects.

forecasting future investments when those investments exhibit lumpiness, and the RM simply does not account for the time value of money to reflect the timing of when future lumpy investments are expected to occur.

The timing of investments is an important factor for accurate marginal costs where investments are lumpy, and only two methods include the time value for estimating forward looking marginal costs: the PWM and the DTIM, discussed in the next two sections.

3. PWM

The PWM recognizes the time value of money where investment lumpiness is exhibited through its discounting of demand growth-related investment streams: it is one of two methods that does this (the other being the DTIM, which is discussed in Section C.4 below). The PWM can be characterized as producing estimates of marginal costs as the deferral values for streams of investments. For the PWM, the important calculation assumption for producing a deferral value is that the entire stream of demand growth-related investments would be delayed one year if expected growth were not to materialize. Thus, the PWM produces marginal T&D costs which vary over time, and thus can reflect the magnitude and timing of planned investments.

The PWM is calculated in several steps, first arriving at a marginal investment per unit of capacity that is then annualized to a marginal cost by applying a CRF and appropriate loadings. Specifically, the several general steps are: (1) calculate a present value of a stream of investments and subtract from that the present value of that same stream of investments, but deferred by one year; (2) divide the difference in present values by the corresponding capacity growth and apply appropriate marginal cost loaders—this results in a marginal investment cost for a change in capacity; and (3) as an extension of the PWM to account for full capital recovery, apply a CRF—of which the RECC is one—to the marginal investment cost from the second step, yielding a per-year deferral value marginal cost per unit of capacity.

4. DTIM

Like the PWM, discussed above, the DTIM is calculated in several steps, first arriving at a marginal investment per unit of capacity that is then annualized to a marginal cost by applying a CRF and appropriate loadings. The first step in the DTIM is to calculate the present value for a stream of investments and divide that present value amount by the present value of the corresponding changes in capacity: the result is a marginal investment cost for a change in capacity. Like the PWM, the marginal investment cost is annualized to a per-year marginal cost per unit of load by application of a CRF and appropriate loadings. In PG&E's proposal for using the DTIM, the CRF is the RECC factor. A significant difference between the calculation of the DTIM described here and the PWM described above is that the DTIM also recognizes the time value of units of capacity.

The DTIM directly considers the value of forward-looking investments in relation to forward-looking capacity growth expectations. Additionally, the DTIM also recognizes that capacity, itself, has value (by discounting units of capacity in the DTIM denominator) where the PWM does not. The DTIM calculation more directly addresses the definition of marginal capacity cost—the cost for a (small) change in capacity investment because of a (small) change in capacity[27]—and accurately reflects PG&E's distribution resource planning process. The PWM, in contrast to the DTIM, indirectly uses the resource planning data: PWM estimates the deferral value for the stream of investments in the resources plan data as an indirect measure of marginal cost.

5. DTIM Is the Superior Methodology

Both the DTIM and the PWM are superior to either the TIM or the RM because, of these four methods, the DTIM and the PWM are the only two that "take into account the proximity or distance [in time] of actual planned

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27 The Commission's original definition of marginal cost adopted in 1981 is "the change in total costs of production caused by a change in output." (D.92749, mimeo, Appendix B, p. 3.) It did not attempt to require a small, or an infinitely divisible small change in output. Resource planning often requires additions that often supply more capacity than is immediately required to meet changes in output. Smaller units of capacity addition are either infeasible due to the nature of added equipment or are simply un-economical.

additions" as recommended in D.90-07-055 (mimeo, pp. 7-8)—the TIM and the RM do not do so. The importance of this attribute is directly related to the lumpiness of investments—the more lumpy the investments, the more important it is to account for the time value of money.

When investments are inherently lumpy, the RM and the TIM attempt to smooth these lumpy additions and cannot meaningfully reflect the timing of future investments in MDCC estimates. The RM and the TIM assume that capacity additions are easily divisible, even infinitely divisible, so that a change in demand growth-related capacity would result in a smaller or larger capacity addition. This is not consistent with the discrete alternatives faced by T&D planners, who often must add capability in large increments.

In contrast to the TIM and the RM, the DTIM and the PWM allow the effects of investment timing and magnitude to be reflected in marginal cost estimates. However, of the two, the DTIM is superior to the PWM. While both of these methods recognize the time value with regard to the timing and magnitude of capital investments, only the DTIM recognizes the time value with regard to units of capacity. Further, the DTIM is the only method that directly uses PG&E's local level resource planning data to calculate marginal costs per unit of capacity per year whereas the PWM indirectly uses the resource planning data to calculate deferral values instead of direct marginal cost values.

D. Conclusion

Compared to the MDCC values adopted in in PG&E's 2014 GRC Phase II Marginal Cost and Revenue Allocation Settlement Agreement,[28] PG&E's proposals in this proceeding at the system level are similar for marginal primary distribution capacity costs and marginal new business on primary distribution capacity costs. In this instance, the current 2017 GRC Phase II values are somewhat higher than previously estimated, with a lesser increase for marginal primary distribution capacity cost than for marginal new business on primary distribution capacity cost. However, for marginal secondary capacity cost at the

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28 For the MDCC values adopted in PG&E's 2014 GRC Phase II, see Attachment to D.15-08-005, "Settlement Agreement on Marginal Cost and Revenue Allocation Issues in Phase II of Pacific Gas and Electric Company's 2014 General Rate Case," Appendix A, pp. A3–A11 .

system level, the result here is considerably lower than the comparable value adopted in PG&E's 2014 GRC Phase II proceeding. In this instance, the system-level estimate for the 2017 GRC Phase II is less than half of the previous estimated value. (However, on an absolute-dollar value basis, this change for marginal secondary distribution capacity cost is smaller than the changes for the marginal-primary and new-business on primary distribution capacity cost changes.) Specifically, the 2017 proposed system-average component MDCC values, compared to the 2014 adopted values (in nominal dollars), are summarized in Table 6-3, below.

TABLE 6-3
COMPARISON OF PG&E'S 2017 GRC PHASE II PROPOSALS TO PG&E'S 2014 GRC PHASE II ADOPTED SETTLEMENT VALUES (SYSTEM AVERAGE)

Line No.	MDCC Component	2017 GRC Phase II Proposed Marginal Cost Values	2014 GRC Phase II Adopted Settlement Marginal Cost Values	Units
1	Primary Distribution Capacity (excluding new business)	$39.43	$37.33	$/PCAF-kW/Year
2	New Business Primary Distribution Capacity	$16.42	$11.26	$/FLT-kW/Year
3	Secondary Distribution Capacity	$1.25	$2.33	$/FLT-kW/Year

PG&E requests that the Commission approve the proposed MDCC set forth herein, including the use of the DTIM method to develop these cost estimates. The DTIM is a superior method for developing accurate, forward-looking marginal costs, where, as here, investments are lumpy both geographically and temporally. This is because the DTIM incorporates the time value of money whereas the TIM and the RM do not. Also the DTIM is the only method that directly uses PG&E's local level resource planning data to calculate marginal costs per unit of capacity per year whereas the PWM indirectly uses the resource planning data to calculate deferral values instead of direct marginal cost values.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 7

MARGINAL CUSTOMER ACCESS COSTS

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CHAPTER 7
MARGINAL CUSTOMER ACCESS COSTS

A. Introduction and Request

This chapter presents Pacific Gas and Electric Company's (PG&E or the Company or the Utility) proposed methodology and results for its marginal customer access costs (MCAC).

The California Public Utilities Commission (CPUC or Commission) has historically distinguished between two types of electric distribution costs: (1) demand-related costs, which vary with the level of electricity demand (in kilowatts (kW)); and (2) customer access-related costs (discussed in this chapter), which vary with the number of customer connections.[1] In this chapter, PG&E presents its proposal for MCAC. PG&E is proposing to continue, in general, the previously-adopted distinction of two components to MCAC:[2] (1) the marginal costs associated with the equipment necessary for connecting customers to the grid (transformer where appropriate, secondary where appropriate, service line, and meter—collectively, the "connection equipment"; and (2) the marginal ongoing costs associated with serving customers once connected to the grid, which are the Revenue Cycle Services (RCS) costs.[3]

PG&E is requesting that the Commission find reasonable PG&E's estimates of MCAC, which are class level sums of the marginal connection equipment cost component of MCAC discussed in this chapter and the marginal ongoing RCS component of MCAC.[4] PG&E also requests that the Commission find that it is reasonable to revert to the Rental Method (RM)[5] for estimating the marginal connection equipment cost component of MCAC in place of the New Customer

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1 In the Federal Energy Regulatory Commission (FERC) system of accounts, both types of costs are considered distribution costs. Therefore, the FERC account descriptions cannot be relied upon to distinguish between demand- and customer-related costs.

2 PG&E first proposed the distinction of two components of MCAC in its 1993 General Rate Case (GRC), and this distinction was adopted by the CPUC in D.92-12-057.

3 In general, RCS costs include the costs of: meter reading; meter maintenance; account maintenance; billing and payment processing; and credit and collections.

4 See Exhibit (PG&E-9), Chapter 8 for discussion.

5 Adopted in D.89-12-057 for PG&E's electric marginal costs.

Only (NCO)[6] method more recently adopted for PG&E. Finally, PG&E requests that the CPUC find reasonable PG&E's adjustments to class definitions that include: (1) assigning the agricultural rate schedules to three sub-classes in place of the prior two sub-classes; and (2) breaking out the Small Light and Power Class (SL&P) class by phase with separate sub-classes for single-phase and poly-phase SL&P customers.

Table 7-1 presents a table of PG&E's customer classes for which MCAC values are estimated.

6 The NCO method, which has also been called the One-Time Hook-Up Cost method, was first adopted for use by PG&E in D.92-12-057 for electric marginal costs and in D.95-12-053 for gas marginal costs.

TABLE 7-1
SUMMARY OF MARGINAL COST CUSTOMER CLASSES

Line No.	By Class	By Rate Schedule
1	Residential[(a)]	
2	Agricultural A[(b)]	
3	Agricultural B – Small[(b)]	
4	Agricultural B – Large[(b)]	
5	Small Light & Power – Single Phase[(c)]	
6	Small Light & Power – Poly Phase[(c)]	
7	Medium Light and Power (ML&P), Secondary[(d)]	
8	ML&P, Primary[(d)]	
9		E-19 Secondary (Large Light and Power (LL&P)[(e)]
10		E-19 Primary (LL&P)[(e)]
11		E-19 Transmission[(e)]
12		E-20 Secondary (LL&P)[(f)]
13		E-20 Primary (LL&P)[(f)]
14		E-20 Transmission[(f,g)]
15	Streetlight[(h)]	
16		TC-1, Traffic Control[(i)]

(a) The Residential class is comprised of all residential rate schedules including E-1, E-6 and E-TOU.

(b) The Agricultural class is comprised of all Agricultural rate schedules (AG-1, AG-R, AG-V, AG-4, AG-5). For more precise marginal cost estimation, PG&E divides the Agricultural class into small agricultural (Ag A) and large agricultural (Ag B). Ag A includes customers with a single motor less than 35 horsepower (hp) or with multiple motors less than 15 total hp. Ag B includes customers with a single motor greater than 35 hp or with multiple motors totaling more than 15 hp. Ag B group is further divided by rate schedule. Customers that are served on Schedules AG 5B or AG-5C are “Large” and customers served on Schedules AG-4B, AG-4C, AG-RB, AG-VB, and AG-1B are “Small.”

(c) The SL&P class is comprised of the small commercial rate Schedules A-1, A-6, A-15 and OL-1. The SL&P schedules are now divided into two SL&P classes: (1) single phase service; and (2) poly phase service. Schedule OL-1 is included in the SL&P single-phase class.

(d) The ML&P class is comprised of the medium general demand rate Schedule A-10 and Schedule E-19V. A-10 Primary and E-19V Primary values are used also for A-10 and E-19V at transmission voltage.

(e) Schedule E-19 is comprised of transmission, primary and secondary service customers with demands up to 999 kW (service on this schedule is mandatory for customers with demands of 500 kW or greater). Marginal costs are determined for mandatory customers on this schedule.

(f) Schedule E-20 is comprised of transmission, primary and secondary service customers with demands of 1,000 kW or greater.

(g) The majority of PG&E’s transmission customers are contained in the E-20 Transmission rate schedule, for customers with demands of 1,000 kW or greater.

(h) The Streetlight class is comprised of all Streetlight rate schedules, primarily LS-1 (PG&E-owned) and LS-2 (customer-owned), as well as LS-3 (metered).

(i) The Traffic Control class, Schedule TC-1, is now fully broken out from the SL&P class where it was formerly included in PG&E’s 2011 GRC Phase II and broken out in PG&E’s 2014 GRC Phase II, but with SL&P class used as proxy for Traffic Control RCS costs and Streetlight class used as proxy for connection equipment costs.

Table 7-2 presents a summary table showing PG&E's estimates of MCAC values by customer class in dollars per customer-year, where those MCAC values are estimated using both the NCO method and RM.

TABLE 7-2
SUMMARY OF PROPOSED TEST YEAR 2014 MCAC
(DOLLARS PER CUSTOMER-YEAR)

Line No.	Customer Class	Sub-Class or Rate Schedule	NCO Values	RM Values
1	Residential		$53.88	$128.77
2	Agricultural	Ag A	$376.68	$732.18
3		Ag B – Small	$2,413.50	$2,202.82
4		Ag B – Large	$3,075.32	$2,279.20
5	Small Commercial	Single Phase	$277.34	$435.36
6		Poly Phase	$491.19	$1,242.86
7	Medium Commercial	A10-S/E-19VS	$670.61	$2,658.13
8		A10-P/E-19VP	$3,313.25	$4,196.36
9	LL&P	E19-S	$3,762.57	$8,383.77
10		E19-P	$4,697.64	$7,370.93
11		E19-T	$6,118.31	$8,791.61
12		E20-S	$5,623.16	$9,203.57
13		E20-P	$5,164.38	$7,837.67
14		E20-T	$7,308.63	$9,981.93
15	Streetlights*		$383.34	$669.72
16	Traffic Control		$744.27	$1,531.27

In Table 7-2, above, the NCO and RM values for MCAC are the class sums of: (1) the marginal connection equipment cost component of MCAC—calculated using the NCO and RM methods; and (2) the marginal ongoing RCS cost component of MCAC (which does not differ between NCO and RM methods).[7]

The remainder of this chapter is organized as follows:

- Section B – Reverting to Rental Method
- Section C – Calculation Methodologies
- Section D – Background
- Section E – Conclusion

B. Revert to RM from NCO Method

This section discusses PG&E's reasons for why it is appropriate to revert to the RM that was adopted prior to the NCO methodology.

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7 See Exhibit (PG&E-9), Chapter 8 for detail of the class-level marginal RCS costs embedded in the MCAC results shown in Table 7-2, above.

PG&E has reassessed its position on the preferred method for estimating the marginal connection equipment cost component of total MCAC. PG&E now proposes adoption of RM over continuation of using the NCO method. The RM had been the adopted method prior to PG&E's 1993 GRC Phase II when the CPUC adopted the NCO method for development of PG&E's electric marginal cost (in D.92-12-057, and last adopted in PG&E's 1996 GRC Phase II, in D.97-03-017). However, the NCO method was rejected for gas marginal costs in favor of the RM in D.92-12-058, issued the same day as the 1993 GRC electric decision. And the CPUC has approved the RM method for use by both Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E).[8]

Both the NCO and the RM are, arguably, theoretically valid methods for estimating costs of connection equipment for customers at the margin. However, in practice, the NCO method suffers from a weakness affecting potential accuracy and reliability of the resulting marginal cost estimates for the connection equipment cost component of MCAC—a weakness the RM does not have.

The NCO method can have considerable sensitivity to the number of new connections in a class as a percentage of existing number of customers in the class (a percentage known as the class new connection rate). The sensitivity is greater for some customer classes compared to others, and with greater sensitivity to the new connection rate comes greater uncertainty in the accuracy of the estimate of the class connection equipment cost component of MCAC. Classes with relatively small numbers of average annual-billed customers tend

8 For SCE, the RM was adopted in D.91-12-076 and was replaced by the NCO method in in D.96-04-050. For Southern California Gas Company, the RM was adopted in D.92-12-058 and then replaced by the NCO method in D.97-04-082. For SDG&E, the RM was adopted for electric in D.88-12-085 and for gas in D.92-12-058; later, the NCO method was adopted for SDG&E gas in D.97-04-082.

to be more sensitive to the connection rate,[9] and inaccuracies in the estimate connection cost component of MCAC drives inaccuracies in marginal cost revenue (MCR) class responsibilities: holding all else equal, it is changes in class MCAC relative to one another, that shifts associated marginal customer cost responsibility between classes. The RM, not relying upon a new connection rate, does not have this weakness where sensitivity to the new connection rate can drive considerable uncertainty in the NCO method's MCAC results.

Under the NCO method, applying the new connection rate to the connection cost component for a class and then adding the ongoing customer service-related cost component applicable to all customers in the class yields a per-customer weighted average total MCAC value for new and existing customers in a class. This class weighted average MCAC value is essentially a short cut for using class MCAC values within the MCR calculations. This class average per-customer connection cost in the MCR calculation does yield arguably a valid *class* cost for connecting the class's new customers.[10] But the resulting class average per-customer result is not directly applicable as the cost of connecting a new customer; rather it is the average cost per customer in a class for connecting a new customer in the class at the margin.

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9 The classes particularly sensitive to NCO method's new connection rate are ML&P – Primary, E19 Secondary, Primary and Transmission (non-voluntary E-19 customers), and E20 Secondary, Primary, and Transmission. Adding a single customer to the 2013-2015 average annual new connections increases the number of new connections for calculation of new connection rates by 7 percent to 60 percent for the above listed classes. And the addition of only a single new customer to the new connection counts for these classes, using the 2015 average annual billed accounts to calculate new connection rates as an example, increases the new connection rates for these classes by 0.1 to 11.1 percentage points. In contrast, adding a single customer to the new connection counts of classes other than for the above named classes increases the respective new connection rates by two orders or more of magnitude smaller percentage points (8-thousandths of a percentage point and smaller).

10 Alternatively, for each class, MCAC cost components could be used directly in the MCR calculation without calculating a class weighted average per-customer for the connection equipment cost component through application of the new connection rate to connection equipment costs for new customers and attributing zero connection equipment costs to existing customers. The MCAC cost components could be used directly in the MCR calculation as follows: (1) the class MCAC connection cost component *without* application of the new connection rate would be multiplied by a billing determinant for number of new class connections; and (2) the ongoing customer service-related cost component would be multiplied by the sum of the class billing determinant for existing customers and new customers.

An argument for the NCO method over the RM was that, as the Commission stated:

> [w]e believe that marginal cost principles dictate that a class with more hookups, relative to others, should have cost responsibility for a larger proportion of associated marginal costs.… The RM does not reflect this fundamental reality. [D.96-04-050, mimeo, p. 65.]

However, PG&E believes that the RM likewise comports with the marginal cost principle of cost causation. From one GRC to another, for classes having greater growth in customers relative to others, the RM connection equipment cost component[11] applied to all customers in a class would result in a faster growing class being assigned a higher proportion of associated marginal customer costs (holding connection equipment costs equal for all classes). This is similar to the NCO method where a higher new connection rate results in a larger portion of the connection equipment cost component[12] being factored into the class per-customer average of the cost for new customers, with zero costs for existing customers, resulting in the NCO method assigning a greater share of marginal cost responsibility to the class. Additionally, under both the RM and NCO methods, where a class has higher connection equipment costs (holding all else equal), the class would be assigned a greater proportion of associated marginal customer costs.

In practice, both the relative growth rate of a class and the relative connection equipment cost for a class affect the assigned proportion of associated marginal customer costs. For classes with higher growth in customers and/or higher per-connection equipment costs, those classes are assigned higher proportions of associated marginal customer costs under both the NCO method and the RM.

PG&E believes that the RM, like the NCO method, comports with the fundamental marginal cost principle of cost causation. With greater numbers of added customer connections and/or higher connection equipment costs relative to other classes, the RM properly assigns responsibility for a larger proportion of associated customer marginal costs.

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11 The connection equipment cost component is calculated as the annual economic carrying cost with appropriate loadings.

12 Calculated as the Present Value of Revenue Requirements (PVRR) for the full lives of the equipment and appropriate lifetime loadings.

Further, in practice, the RM does not have the weakness of the NCO method where the NCO estimate of the connection equipment cost component of MCAC is subject to considerable sensitivity to the new connection rate. For the NCO method, the differential sensitivity of classes to the new connection rate affects the accuracy of the end assignment of marginal cost responsibility to classes: it is the relative changes in the connection equipment cost component of MCAC among classes that, holding all else equal, shifts among classes the MCR responsibility for associated marginal customer costs.

C. Methodologies

This section discusses the methodologies PG&E used for developing its proposed MCAC estimates, and the changes PG&E has made to its models for estimating MCAC values subsequent to PG&E's 2014 GRC Phase II MCAC proposal.[13] To improve accuracy, PG&E has incorporated some data improvements that are in addition to modifications to methodologies in the model to improve accuracy. Additionally, changes have been made to the customer classes for which MCAC values are to be estimated.

The summary of estimated MCAC values by class presented in Table 7-2 are for total MCAC by class where those class values are the sum of two MCAC components: (1) of marginal connection equipment costs; and (2) marginal ongoing RCS costs. For each customer class, the total MCAC is calculated by the following formula for the NCO method and the RM, respectively:

$$\begin{aligned} MCAC_{NCO} = & \text{ (Customer New Connection Rate} \times \text{NCO Marginal Connection Equipment Cost)} \\ & + \text{ Marginal Ongoing RCS Costs} \end{aligned}$$

$$\begin{aligned} MCAC_{RM} = & \text{ Marginal Connection Equipment Cost} \\ & + \text{ Marginal Ongoing RCS Costs} \end{aligned}$$

The marginal ongoing RCS cost component shown in the above formulas is independent of the methodology for calculating the marginal connection

[13] PG&E notes that the version of the MCAC model used for developing PG&E's 2014 GRC Phase II proposed MCAC values produced estimates using both the NCO method and the RM, as does the current version of the MCAC model used in this marginal cost showing.

equipment cost component. As in PG&E's last several GRC Phase II marginal cost showings, PG&E proposes using its RCS model results—with significant improvements.[14] Given that this marginal ongoing RCS cost component is discussed in detail in Chapter 8—and that the methodology for this component is independent of the methodology for the marginal connection equipment cost component—the remainder of this section focuses only on the marginal connection equipment cost component of total MCAC.

1. Customer Classes for MCAC Estimates

PG&E estimates MCAC values for the residential, agricultural, streetlight, traffic control, and small-, medium-, and large light and power classes.

Since the last GRC Phase II, PG&E has made changes to categorizations of the sub-classes for both the agricultural sub-classes and the SL&P sub-classes. Prior to this marginal cost showing, the agricultural class was divided into two sub-classes: agricultural small and agricultural large. Now, the agricultural class is divided into three sub-classes: (1) Agricultural A; (2) Agricultural B–small; and (3) Agricultural B–large. Similarly, the SL&P class previously was a single class, but it is now divided into two sub-classes: (1) SL&P–single phase; and (2) SL&P–poly phase.

There are no such changes for the other classes. The ML&P class continues to be divided into two parts: those customers served at secondary, versus primary distribution voltages. The LL&P class continues to be divided into two basic rate schedules: (1) Schedules E-19; and (2) E-20. The Schedule E-19 group contains customers with demands between 500 and 999 kW, while the Schedule E-20 group includes customers with demands of 1,000 kW or greater.[15] But then, Schedules E-19 and E-20 continue to each be further divided into one of three voltage service levels: secondary, primary, and transmission voltage. Additionally, for purposes of estimating the connection equipment component of MCAC, PG&E assigns all E-19 Voluntary customers to the

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[14] See Exhibit (PG&E-9), Chapter 8 for description.

[15] The customer's maximum billing must have exceeded 499 kW (for Schedule E-19) or 999 kW (for Schedule E-20) for at least three consecutive months during the most recent 12-month period to qualify for these rate schedules.

respective classes for the otherwise applicable schedules using demand data. These distinctions are required to capture significant differences in the costs of connection equipment and costs of providing ongoing customer services to each of these sub-categories of customers.

2. Underlying Connection Equipment Cost Data

The same data for new connection equipment by class underlie both the RM and the NCO method calculations for the marginal connection equipment cost component of MCAC.

PG&E's 2017 GRC Phase II marginal connection equipment cost estimates are based on an analysis of 2013-2015 customer connection cost data obtained from PG&E's Customer Construction Billing System (CCBS).[16] The CCBS data are supplemented with new connection contract-specific transformer data from PG&E's Fast Flow Estimating new connection job cost field estimating tool, certain other new connection data from PG&E's Main Line Extension System and rate schedule information from the Customer Care and Billing (CC&B) system.

The use of actual job estimate costs as a data source for this approach to computing marginal costs of connecting new customers differs from previously adopted methods in a significant way. This approach uses costs that are computed based on actual field-produced job cost estimates obtained from customer contracts in PG&E's CCBS application rather than a limited number of estimated "typical customer connection" costs[17] as was used in the methodology adopted in PG&E's 1990, 1993 and 1996 GRC Phase II proceedings. Using actual field-estimated job costs in place of "typical customer connection" costs represents a vast improvement in the accuracy of the methodology and should be adopted.

In this 2017 GRC Phase II showing on customer marginal costs for new connections, PG&E uses 2013-2015 data representing more than

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16 The CCBS application is used to bill out customer requested construction work for New Business and Work Requested by Others. This application applies the tariff and accounting rules to the project costs to determine how much the customer pays and how much PG&E pays.

17 "Typical job costs" were developed for each of the various customer classes using engineering estimates produced from PG&E's former COMPRESS estimating tool.

101,000 new service connections. Non-residential marginal customer connection costs are based on contract data for more than 16,000 new service connections. Residential marginal customer connection costs are based on 2013-2015 contract data for more than 88,000 new connections.

Similar to what was done in PG&E's 2003, 2007, 2011 and 2014 GRC Phase II MCAC calculations, the 2017 GRC Phase II marginal customer connection costs presented here are the average (i.e., mean) net PG&E connection cost for each customer class, that is, exclusive of applicant-borne costs as determined by Rule 16.[18,19] PG&E proposes to use an average of the net new connection cost because it recognizes the full range of data, including the valid data on costs at the low- and high ends of the cost spectrum.

The following process is used to estimate new connection costs by customer class:

a. Determine mean cost of a residential connection (where "total service cost" as referenced here and in the remainder of this section is inclusive of transformer and meter costs):
   - For each residential contract, determine PG&E's share of the new connection costs, which is limited to the per-meter allowance granted.[20] For billing letters (abbreviated contracts for certain

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[18] For PG&E's 2011 GRC Phase II MCAC proposal, as updated January 7, 2011, *see* A.10-03-014, Exhibit (PG&E-15), Chapter 7. In its 2011 GRC updated marginal costs, PG&E adopted the Office of Ratepayer Advocates' (ORA) proposal to use median, as opposed to mean, costs to lessen the influence of what ORA was concerned might be outlier job estimate costs. However, marginal costs were settled in that proceeding without a specific finding on this point. In PG&E's 2014 GRC Phase II proposal, PG&E reverted to calculating average, i.e., mean, net customer connection costs for each class as had been done for its proposals in the 2003 and 2007 GRCs. PG&E is again using the mean net customer connection costs in this 2017 GRC proposal. PG&E continues to see a wide dispersion of new connection costs for the non-residential customer classes. Thus PG&E has concluded that this dispersion of costs is a normal occurrence, not merely cost data with "outliers." The general rule on outlier removal is that, if an outlier in question has a high probability of repeating in the future, that cost should not be removed. PG&E has no basis for assuming that any of the costs of new connections that occurred from 2013-2015 would not have the same probability of occurrence in the future.

[19] Background on Rule 16 limits to PG&E's new connection equipment cost responsibility is provided in Section D, below.

[20] For residential new connection costs analyses, the allowance is $1,918 for all new connection contracts on and after July 1, 2009 (Advice Letter 3438-E-A).

simple residential new connections of fewer than five lots), the applicants (customers or developers) are responsible for any connection costs exceeding the service allowance. For each residential full contract, where the applicant may select the 50 percent nonrefundable discount option (from Rule 15), if this option is selected, then determine PG&E's additional cost responsibility for service costs in excess of the allowance.

- For the mean residential new connection cost, PG&E obtains the breakout of the transformer, service and meter costs.

b. Determine mean meter and service cost of non-residential new connections:

- For non-residential new connections, determine PG&E's share of new connection costs for each contract in same manner as for residential full contracts; and
- After matching Service Point and Premise ID to rate schedule data from CC&B, calculate mean meter and mean total service costs by non-residential customer class.

Finally, for each class's mean new connection cost, obtain the breakout for the transformer, service and meter costs.

3. RM Calculations

In general, there are two steps for the RM MCAC calculation for the marginal connection cost component. First, at the margin, the per-customer access equipment costs for a connection are determined for each customer class using the actual new connection contract cost data discussed above. Second, the per-customer access equipment costs are converted to an annualized real carrying cost by using a Real Economic Carrying Charge (RECC) factor and other appropriate loaders. The development of the RECC factor and the other loaders is discussed in Chapter 13, "Marginal Cost Loaders and Financial Factors," of this exhibit.

Finally, to arrive at the class-level total MCAC estimates using the RM for the connection cost component, PG&E adds the marginal ongoing customer access (RCS) costs estimated for the respective class to the per-customer cost responsibility for connection equipment. This total, by class, of access equipment and ongoing cost responsibility is the RM's total MCAC result, by class, shown in Table 7-2.

4. NCO Method Calculations

Although PG&E believes the CPUC should revert to the RM in this proceeding, for the sound reasons set forth above, PG&E is providing estimates using the NCO method as well as the RM that was adopted by the Commission prior to adopting the NCO method for PG&E.

In general, there are four steps for the NCO MCAC calculation for the marginal connection equipment cost component, with a final step to arrive at the total MCAC estimate.

First, the per-customer access equipment costs for a new connection are determined for each customer class. These class-level new connection costs are identical to those used for the RM MCAC estimates.

Second, the per-new customer access equipment costs are converted to a PVRR using a PVRR factor and other appropriate loaders and financial factors, resulting in the marginal cost responsibility per new customer in each class.[21]

Third, factors for lifetime operations and maintenance (O&M), stated as percentages of the respective equipment capital cost, are applied to the respective connection equipment. The results of this third step are values representing the present value of O&M and other appropriate loaders for maintaining transformers and services over their lives.[22]

Fourth, for each class, the sum of marginal cost responsibility for new connection equipment and corresponding lifetime O&M for transformers and services[23] is converted to the per-customer class cost responsibility for new connection equipment and corresponding lifetime O&M by multiplying the per-new customer marginal cost responsibility by the class's new connection rate. The customer new connection rate is simply the ratio of the number of

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21 See Exhibit (PG&E-9), Chapter 13 for discussion about the development of the PVRR factor and loaders.

22 See Section D below for additional background on lifetime O&M.

23 A lifetime O&M factor, with other appropriate loadings, is not applied to meters; the ongoing cost for maintaining and servicing meters is captured in the marginal ongoing RCS costs.

new customer connections in any given year to the average number of customers[24] for the preceding year. The result of this fourth step effectively is to produce a weighted average marginal connection equipment cost, including O&M and other appropriate loaders, per customer in the class using the new connection rate as a weighting factor applied to the sum of marginal connection equipment costs and corresponding lifetime O&M for new customers and assuming $0 marginal connection equipment costs for existing customers.

Finally, for the total MCAC estimate using the NCO method for the marginal connection equipment cost component, for each class, the ongoing customer access (RCS) costs estimated for the class is added to the class per-customer cost responsibility for new connection equipment and corresponding O&M. This total by class of new connection equipment and corresponding O&M and ongoing cost responsibility is the NCO method's total MCAC result by class as shown in Table 7-2.

5. Incremental Methodology Improvements

PG&E proposes five incremental changes to improve the accuracy of its previously adopted NCO methodology in the 1996 GRC, where the first two are incremental changes also applicable to improving the accuracy of the RM estimates for the marginal connection equipment component of total MCAC. PG&E believes that these five changes represent important incremental improvements to the accuracy of estimated MCAC.

Incremental changes improving the accuracy of MCAC estimates applicable to both the proposed RM and the prior NCO methods are:

- PG&E proposes setting the customer marginal connection equipment cost component in the calculation of MCAC equal to PG&E's share of the new connection costs pursuant to the service extension tariff Rule 16.[25]
- PG&E proposes to remove fixed costs from the computation of MCAC for such services as meter reading, billing, and maintenance of

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24 The number of "customers" is really the number of "billed accounts"; the text continues to refer to the number of "customers" instead of "billed accounts" to be consistent with past terminology.

25 See Section D below for additional background on Rule 16.

customer connection equipment. The removal of these fix costs is achieved through the design of the RCS model, where only financial costs applicable to relevant RCS activities are included in the RCS calculations. The previously adopted MCAC methodology[26] failed to distinguish fixed costs from variable costs, causing MCAC to be overstated to the detriment of economic efficiency.

Incremental changes improving the accuracy of MCAC estimates applicable to only the prior NCO method are:

- PG&E is replacing its proxy method for determining the number of new connections—where the proxy is calculated as the year-to-year change in the number of accounts for each customer class—with a forecast of customer class new connections.[27]
- PG&E proposes using a lifetime O&M approach applicable to only the access equipment for new connections instead of allocating O&M to all customer connections, both new and existing.
- PG&E proposes to eliminate access equipment replacement costs applicable to all connections, both new and existing.[28] When the NCO methodology was originally adopted in D.92-12-057, there was no inclusion of access equipment replacement costs applicable to all connections. The inclusion of these replacement costs first appeared in MCAC adopted for limited purposes in PG&E's 1996 GRC (D.97-03-017). In this GRC, PG&E proposes returning to the adopted

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26 PG&E's MCAC methodology was last litigated in the Company's 1996 GRC Phase II and adopted in D.97-03-017.

27 See Subsection 6 below for additional discussion of this change.

28 In D.92-12-057, connection equipment replacement costs, applicable to all customer connections, were not included in MCAC. However, connection equipment replacement costs were explicitly included in MCAC adopted for limited purposes in D.97-03-017. PG&E proposed the inclusion of replacement costs in MCAC in its 1999, 2003, 2007 and, initially, 2011 GRC Phase II showings, but marginal costs were not fully litigated in those cases. (PG&E's 1999 GRC Phase II proceeding was suspended due to the California energy crisis and marginal costs were settled in the 2003, 2007 and 2011 GRC Phase II proceedings.) PG&E's proposal here to exclude connection equipment replacement costs would represent a return to the methodology the CPUC adopted in D.92-12-057 and is consistent with Commission's finding to eliminate replacement costs from gas MCAC in PG&E's 2005 BCAP (D.05-06-029, mimeo, Finding of Fact 6, p. 26).

NCO cost methodology with respect to access equipment replacement costs, i.e., that these replacement costs not be included.[29]

6. MCAC Model Changes

PG&E retains a number of improvements made to the primary MCAC model it presented in the 2014 GRC. In addition, for this 2017 GRC processing, PG&E has made further refinements so that the model now reflects:

- Processing of raw data in SAS[30] with aggregated results passed to Excel for use in the main MCAC calculation model.
- Consolidation of Excel files used in MCAC calculations into one Excel MCAC model.[31]
- Improved model transparency and usability by adopting a revised standard model governance structure that follows a logical model flow based on a structure of defined input, calculation, and output worksheets. Additionally, cover sheets and built-in model links allow the user to navigate the model easily.
- Improved model presentation and structure, including through revised color coding and more consistent formatting.
- Improved model documentation with data sources clearly defined.

In addition to the above refinements, PG&E retains several important improvements to the primary MCAC model inputs:

- As was first proposed in the 2014 GRC Phase II marginal cost showing, PG&E retains improved data sources, including actual transformer costs linked to individual jobs as opposed to using class-level typical transformer costs as proxy data, and improved new connection count data directly from the CC&B system for multiple historical years.

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29 Similarly, PG&E believes that equipment replacement costs should not be included when estimating total MCAC using the RM for the connection equipment cost component.

30 SAS is a software system developed by SAS Institute that provides advanced data analytics and secure management for very large datasets.

31 The primary MCAC model receives aggregated costs data from a separate intermediate Excel model to pass aggregated data from SAS. The analysis and aggregation of connection costs data remains separate, due to the highly confidential nature of the customer-level connection costs.

- For RCS inputs to the primary MCAC model, PG&E has revamped the RCS model, replacing the model used in the 2104 GRC Phase II showing. The primary MCAC model receives data from PG&E's completely redesigned and rebuilt RCS and the "Other Account 903" Excel model using a survey methodology has been eliminated because these "Other Account 903" costs are captured in the redesigned and rebuilt RCS model.[32]
- For the determination of the number of new connections, PG&E retains an important revision from PG&E's 2011 GRC Phase II. Starting with PG&E's 2011 GRC Phase II Application, and continuing in its 2014 showing as well as in this application, PG&E revised its method for determining the number of new customers (really new customer connections), which is the numerator in the customer new connection rate. In GRCs prior to 2011, the number of new customer connections had been estimated as the difference in the year-end customer counts in two successive years as a proxy for new connections.[33] Using the difference in customers as a proxy for new customer connections can be problematic, especially for customer classes that show net declines in the number of customers. This proxy fails to capture the true rate of new connections occurring because the proxy is the net of new connections and disconnections. Even with net declining customers in a class due to disconnections, new connections do occur and the class needs to cover its cost of those new connections by recognizing new connections in isolation, rather than using new connections net of disconnections. For this 2017 GRC, PG&E proposes using new connection forecasts by customer class to calculate new connection rates instead of the proxy calculation using net changes in number of customers. PG&E believes this improved method provides more accurate estimates of customer new connection rates than did the pre-2011 proxy method.

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32 See Exhibit (PG&E-9), Chapter 8 for discussion of re-designed and rebuilt RCS model.

33 D.92-12-057, which first adopted the NCO method, called for use of three years of recorded customer data to estimate the customer new connection rate.

These refinements and improvements to PG&E's MCAC model not only make it easier for all parties to use, but make its results more accurate as well.

D. Additional Background

This section provides additional background about PG&E's marginal customer access cost proposals and provides further discussion for MCAC on methodological topics as noted above.

1. General Background

For most customer classes, the access costs for new connections comprise the meter, service line, and, as applicable to the situation, final line transformer and secondary conductor between the transformer and service line. Additionally, all customers have ongoing costs, including meter maintenance, meter reading, billing, and other customer service-related costs. During the first decade of marginal cost-based electric ratemaking in California (in the 1980s), Commission-adopted marginal cost methodologies generally did not distinguish between costs attributable to new customers and costs attributable to existing customers. In decisions up to and including D.89-12-057, the Commission adopted the "rental method," which estimates the MCAC connection equipment component as the annualized cost of a transformer (for customers connected at secondary distribution voltages), service line, and meter (sometimes referred to as "TSM" costs).[34]

Subsequently, in its 1993 GRC, PG&E first proposed a new method of estimating MCAC connection equipment costs as the one-time costs of

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34 In D.89-12-057, the Commission recognized that the distribution system performs both a capacity (demand-related) function and customer access function, where demand-related costs are assigned to marginal capacity costs, and access-related costs are assigned to MCAC. The distinction between these functions is not always clear. (D.89-12-057, mimeo, p. 202.) Primary distribution costs are treated as capacity costs (*Ibid.*, mimeo, p. 203). Secondary distribution equipment includes secondary conductors, final line transformers, service drops and meters (*Ibid.*, mimeo, p. 203). While this secondary system primarily provides customer access to the electric distribution system, the Commission accepted PG&E's view that it also has a capacity component and assigns secondary investments for demand-related growth to marginal distribution capacity costs (*Ibid*., mimeo, p. 206). The remainder of the secondary equipment, along with associated ongoing costs such as meter services, meter reading, billing, and other customer services are assigned to MCAC.

the connection equipment attributable to the new customers only—the NCO method.

2. Rule 16 Service Extension Tariffs

PG&E again proposes to capture new connection cost sharing in this 2017 GRC proposal. This cost sharing is defined by the service extension tariff Rule 16 and quantified with analyses of actual CCBS contract data. Capturing this cost sharing ensures that customer new connection cost results only capture the marginal cost incurred by PG&E. When a customer or developer applies for electric service at a new location, the following costs are incurred, in most cases:

a) The cost of planning, designing and engineering service extensions using PG&E's design standards for design, materials and construction;

b) The cost to install primary or secondary service conductors (service drops) to connect to individual customer service locations (and, for overhead service conductors, the cost of poles that may be needed to support the service conductors); and

c) The cost to install a meter for each new customer.

These three items are the major cost items that fall within the purview of the Commission's service extension tariff (Rule 16). When a new customer or developer applies for electric service at a new premise, Rule 16 governs which costs of connecting new customers are borne by the Utility (and therefore included in rates), and which costs are directly borne by the applicants (customers or developers) for new service (and therefore not included in rates). Further, Rule 16 governs which costs are subject to allowance: allowances granted to customers or developers are effectively costs borne by the Utility and are properly included in utility marginal costs.

Prior to 1995, the line extension rules provided allowances that were sufficiently generous that the Utility, and ultimately customers, paid most costs of connecting new customers.[35] This meant that the line extension rules had no practical effect on MCAC. This situation began to change in the mid-1990s due to a series of decisions in the Commission's Line

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35 In general, an applicant for new service was required to make a deposit to cover the "refundable cost" of connection. Deposits were usually fully refunded, over a period of up to 10 years.

Extension Rulemaking (R.92-03-050). Beginning in 1995, Rules 15 and 16 were modified so that allowances had to be "revenue justified." A "flat" per-meter residential allowance was adopted for Electric Rule 15 (and referenced by Rule 16). In 1998, transformers, meters and services were, for the first time, included in the customer's costs, subject to allowance. With these changes, developers and customers are now often required to absorb a portion of new customer connection costs.

PG&E proposes to use the full refundable cost[36] of the service extension (the cost of the customer access equipment) for the purpose of estimating the new connection component of the MCAC. This amount excludes any customer/developer contributions to the connection costs under tariff Rule 16. These customer contributions (if any) are recognized, for the first time, under PG&E's proposed methodology, and serve (by their exclusion) to reduce the estimated MCAC. Thus, in this proceeding PG&E proposes to set the new customer connection cost component of MCAC equal to the Utility's share of the costs of connecting new customers as determined pursuant to Rule 16.

In summary, the service extension rule should govern the calculation of MCAC, because Rule 16 determines which customer connection costs is the responsibility of the Utility and enable applicant-borne costs to be identified and excluded from marginal costs used for ratemaking. PG&E continues to propose that these costs be set to the Utility's share of the installation costs under Electric Rule 16, "Service Extensions." PG&E's costs are therefore net of customer contributions.

3. Lifetime O&M for New Connections

Under the NCO method, the cost imposed on the system for access equipment associated with new customers at the margin should be only

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36 Rule 16 specifies that certain items are normally the cost responsibility of the developer or customer. Such items are excluded from service costs subject to allowance and from the refundable costs. Generally, applicants for new service have the option to install such facilities at their own expense, or to make a nonrefundable payment to PG&E to cover the cost of utility installation. In either case, the cost of such facilities is properly excluded from the marginal costs used for ratemaking.

the costs of the access equipment—final line transformers[37] as applicable, secondary as applicable, services and meters—installed to connect the new customers to PG&E's distribution system and any related lifetime maintenance and other costs directly related to the added access equipment.[38] Once a new connection is established, it imposes on the system the obligation to maintain that equipment going forward. For existing connections, the number of connections having customer turnover and temporary vacancies does not affect the obligation to maintain the access equipment at the margin.[39] It is the addition of new access equipment for new connections that imposes an incremental obligation. To capture these incremental maintenance cost obligations, PG&E proposes the application

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[37] As distinct from distribution transformers, which are included in demand-related marginal distribution capacity costs.

[38] This Lifetime O&M methodology is applicable only to the NCO methodology where the connection equipment costs under the NCO methodology for new customers are captured as the present values of revenue requirements for the new connection equipment capital investments. Therefore, the O&M costs and other relevant loadings are similarly captured as the present value of those costs for the lifetimes of the respective connection equipment. Under the RM, these O&M costs and other relevant loadings are captured as part of the annualized RM connection equipment costs via loadings to the RECC factors that are applied to the connection equipment capital investments.

[39] Replacement costs of customer access equipment were not included in the marginal costs adopted in PG&E's 1993 GRC Phase II (D.92-12-057), but were included in the marginal costs adopted for limited purposes in PG&E's 1996 GRC Phase II (D.97-03-017). PG&E proposed inclusion of replacement costs in its 1999, 2003, 2007 and, initially, 2011 GRC Phase II showings. However, PG&E is not proposing the application of replacement costs to all customer connections, existing and new, in this instant GRC Phase II showing. Replacement costs are implicitly included in the revenue requirement scalars applied to the new connection costs. As these costs should only be applied for new connections and not existing connections, this application is sufficient and any explicit inclusion of replacement costs would be double-counting these costs.

of lifetime O&M adders to final line transformers and services.[40] (This lifetime O&M methodology is not applied to meters since meter maintenance costs are capture in the RCS models.)

PG&E first proposed the application of lifetime O&M cost adders in the Company's 2003 GRC and again in its 2007, 2011 and 2014 GRC proceedings.[41] The application of lifetime O&M adders to access equipment installed for new connections captures the present value of the ongoing maintenance cost obligations that those new connections impose on the system. PG&E proposes lifetime O&M adders for two of three primary access equipment asset types: transformers and services. The lifetime O&M adder for each of these equipment asset types is generally calculated as follows:

1) The O&M expense is calculated for a unit of capital for each year of the asset's life, based on the relation of annual O&M to capital charge using loaders and financial factors;
2) Each year of the expenses per unit of capital in (1) is discounted to the present by application of a discount factor and summed to total present value of expenses per unit of capital;
3) Additional capital costs are captured through a revenue requirement scalar per unit of capital, where the revenue requirement scalar represents the levelized annual revenue requirement factor for a unit of invested capital plus associated return and taxes; and

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40 The term "lifetime O&M adder" is used for simplicity. This adder also includes Administrative and General, common and general plant costs, and other capital-related costs arising from the added transformers and service for new connections over the equipment lives. Incorporating O&M costs by way of lifetime O&M adders differs from the prior 2003 and 2007 proposals. In those proposals, PG&E allocated an estimate of marginal O&M to access equipment for all customer connections, existing and new. Here, PG&E only proposes O&M costs for new connections. The number of new connections affects O&M costs. Customer turnover and temporary vacancies has little impact on O&M for existing connections: the number of connections having customer turnover and temporary vacancies does not change, at the margin, the O&M costs for those connections. It is new connections that, at the margin, add O&M costs.

41 In the 2003 and 2007 GRCs, the proposed lifetime O&M adders were applicable to certain primary and secondary distribution equipment that was outside of the customer access equipment boundary proposed in this GRC Phase II: this boundary is at the final line transformer. PG&E is not proposing to include lifetime O&M for any distribution equipment on the distribution capacity side of a marginal distribution capacity/marginal customer access boundary designated at the final line transformer.

4) The present value of expenses per unit of capital in (2) is added to the additional capital costs per unit of capital in (3) resulting in the lifetime O&M adder per unit of capital, expressed as a percentage.[42]

The mean new access equipment costs for transformers and services are multiplied by the respective lifetime O&M adders for each customer class. The results are the present value of the annual revenue requirement for lifetime O&M costs imposed by each new connection in each class for these two types of access equipment.

This lifetime O&M proposal is consistent with marginal cost theory. Because when a customer chooses to connect to PG&E's distribution system, the customer causes plant additions for customer access equipment. That added access equipment must then be maintained for its life. Therefore, PG&E adds the present value of the lifetime O&M expenses—where expenses are dollar-for-dollar a revenue requirement—to the PVRR for the new customer access equipment calculated in the NCO methodology. Describing the economic ideal for the application of marginal costs to utility rates, Alfred E. Kahn, in Volume I of his seminal work on marginal costs for regulated entities, The Economics of Regulation: Principles and Institutions,[43] states:

> [T]he economic ideal would be to set all public utility rates at short-run marginal costs…; and these [marginal costs] must cover all sacrifices, present and future…for which production at the margin is causally responsible.[44] (Footnotes omitted.)

In a footnote to the above excerpt, Kahn states:

> Strictly speaking, any postponed cost incurrences should be incorporated…only at present, discounted value.[45]

The lifetime O&M methodology is consistent with this application of marginal costs in that it captures a stream of future costs at a present, discounted value where the customer taking new service with new connection equipment is causally responsible for this stream of costs.

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42 See the workpapers supporting this chapter for details of the calculation.

43 See Kahn, The Economics of Regulation: Principles and Institutions, Volume I, 1970, John Wiley & Sons, Inc., New York.

44 *Ibid.*, p. 75.

45 *Ibid.*, FN 27, p. 75.

E. Conclusion

In this chapter, PG&E proposes five changes to the MCAC methodology previously adopted in PG&E's 1996 GRC. While these changes are to the previously adopted NCO methodology, the first two changes are also directly applicable to improving the accuracy of PG&E's RM MCAC proposal:

- First, for the RM and the NCO method, PG&E proposes that the new customer connection cost component of MCAC be set equal to the Utility's share of the costs of the meter, service extension, (secondary as applicable) and transformer (as applicable) pursuant to Rule 16;
- Second, for the RM and the NCO method, PG&E proposes to remove fixed costs from the computation of MCAC for such services as metering (meter services and meter reading), billing, and other customer services;
- Third, for the NCO method, PG&E proposes calculating the new connection rate based on a forecast of new connections by customer class in place of a proxy method that estimated the number of new connections from year-to-year customer class net changes in the number of accounts;
- Fourth, for the NCO method, PG&E proposes the application of lifetime O&M adders to capture additional maintenance costs imposed on the system driven by the number of new connections only, as opposed to allocating O&M to all customer connections, existing or new; and
- Fifth, for the NCO method, PG&E proposes no inclusion of explicit replacement costs for customer access equipment applicable to all connections because customer turnover and temporary vacancies have little bearing on equipment failure rates and no impact on equipment obsolescence requiring replacements.

PG&E's proposed MCAC should be adopted because PG&E's approach:

- Conforms to the fundamental marginal cost principle of cost causation;
- Improves upon previously used data and methodology;
- Better conforms to the Commission's current service extension tariff Rule 16; and
- Will result in more equitable and economically efficient rates.

And most importantly, PG&E believes it is appropriate to revert back to the RM that was adopted for PG&E prior to the NCO method, and continues to be by both SCE and SDG&E, rather than use the NCO method. The RM method, in practice, does not share the weakness of the NCO method where sensitivity of that method's estimate of the connection equipment cost component of MCAC to the class new connection rates (where some classes are considerably more sensitive than others) results in considerable uncertainty in the accuracy of the estimates. PG&E also believes, counter to a prior Commission finding, that the RM, like the NCO method, comports with marginal cost principles with respect to cost causation: the RM does assign responsibility for a higher proportion of associated marginal customer costs where classes are growing in customers faster relative to others and where classes have higher connection equipment costs.

As the Commission has repeatedly recognized, and reaffirmed in its 2005 issuance of California's Energy Action Plan II)[46] it remains vitally important to "adopt rates based on clear cost-causation principles." Accordingly, the Commission should adopt PG&E's marginal cost proposals to foster equitable and economically efficient ratemaking by ensuring that rates are substantially aligned with cost causation, so that customers bear the costs that they cause.

46 See California's Energy Action Plan II, issued September 21, 2005, Electric Market Structure "Key Action" No. 1, p. 10, calling for the investor-owned utilities to "adopt rates based on clear cost-causation principles."

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 8

MARGINAL REVENUE CYCLE SERVICES COSTS

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MARGINAL REVENUE CYCLE SERVICES COSTS

A. Introduction

In this chapter, Pacific Gas and Electric Company (PG&E) introduces an improved Revenue Cycle Service (RCS) model for estimating its ongoing cost component of marginal customer access costs. PG&E requests that the California Public Utilities Commission (CPUC) approve both the improved model and the resulting estimates of marginal ongoing costs for account setup, billing and payments, credit and collections, meter services and meter reading. The RCS model proposed here is superior because it estimates from a longer-run economic perspective the marginal costs for real assets related to increasing the total number of customer that PG&E can serve each year, such as bill printing hardware costs. The RCS model, including the significant improvements to the RCS model used in the 2014 General Rate Case (GRC) Phase II filing, is discussed below.

B. 2017 GRC RCS Model

1. Methodology

The RCS model is a top-down, activities-based model to calculate marginal ongoing customer access costs. It produces results by rate schedule, which are then aggregated into results by customer class. The activities in the RCS model have been completely revised to reflect PG&E's current billing and payments, credit and collections, customer inquiry, meter services and meter reading operations. PG&E's current operations and organizational structure are expected to be in place for the 2017 test year. Figure 8-1 below lists the type of activities included in the RCS model. Each specific activity includes an annual cost and a cost driver for the activity. A cost driver is a measure of how much each rate schedule uses a particular activity. The activities in the RCS model are sufficiently refined such that, as the cost driver increases, the annual cost for that activity increases in direct proportion. The annual cost of each activity is allocated to each rate schedule in proportion to its cost driver. The allocated costs are then divided by the number of customers for the year to arrive at the annual cost per customer for each rate schedule.

The data used in the RCS model can be grouped into three categories: financial costs, cost drivers, and customer counts. The financial cost data are taken from PG&E's financial accounting system, with the recorded financial costs for labor fully loaded, meaning that costs such as medical benefits are included in the labor costs in addition to salary costs. Data for the cost drivers are provided by the PG&E departments responsible for the underlying services. Subject matter experts in Business Finance and Customer Care were engaged to determine which ongoing customer activities to include in the model and for these activities the appropriate financial costs and cost drivers to use.

FIGURE 8-1
TYPES OF ACTIVITIES INCLUDED IN RCS MODEL

2. Illustrative Example

The following example uses illustrative numbers to demonstrate the actual calculations in PG&E's improved RCS model. Consider the meter reading activity of electronically acquiring data from SmartMeter™ devices. Suppose in 2014, PG&E incurs $100,000 to electronically acquire data from smart meters for all rate schedules. The cost driver for this activity is the number of digitally polled smart meters. In 2014, if PG&E digitally polls 8,000,000 SmartMeter™ devices for all rate schedules, and 2,000,000 of them are for E1 residential customers, then the allocated cost for electronically acquiring data for E1 residential customers is $100,000 x (2,000,000 / 8,000,000) = $25,000. The above steps are repeated for the other billing and payments, credit and collections, customer inquiry, meter reading, and meter service activities. New account setup costs are then broken out since they are one-time costs for customers new to PG&E service territory and not ongoing monthly costs for existing customers. By service, assume the allocated costs for residential customers on Schedule E-1 are: $100,000 for account setup; $10,000,000 for billing and payments; $2,000,000 for credit and collections; $5,000,000 for meter reading; and $10,000,000 for meter services. The new account setup costs are then divided by the number of new customers, while the other costs are divided by the number of ongoing customers. In 2014, if there are 10,000 new E-1 residential customers, and 500,000 ongoing E-1 residential customers, then the costs per customer per year in this example for E-1 residential customer are: $100,000 / 10,000 = $10 for account setup; $10,000,000 / 500,000 = $20 for billing and payments; $5 for credit and collections; $10 for meter reading; and $20 for meter services. Finally, as the last step in the example, the total RCS costs per customer per year for E-1 customers is $10 + $20 + $5 + $10 + $20 = $65.

C. Improvements From Previous GRC Filings

The new RCS model represents a significant improvement over the RCS models used in PG&E's previous GRC Phase II showings. The new model achieves the following improvements in comparison to PG&E's 2014 GRC RCS model:

- Improves the accuracy of the marginal RCS costs results by:
  - Updating the Billing and Payments and Credit and Collection Activities to Reflect Current PG&E Operating Procedures: PG&E's 2014 GRC RCS model uses those activities that were current in 2003, which are no longer relevant given the increased utilization of electronic payment options by customers.

- Using Actual 2014 Financial Cost Data for All RCS Activities: Actual financial data inherently incorporate the per-unit cost of labor and materials and the frequency of usage of labor and materials in determining the cost of RCS activities. In contrast, PG&E's 2014 GRC RCS model estimates the cost of the billing and payments and credit and collection activities as the number of occurrences times the frequency times the number of minutes per occurrence times the fully loaded labor rate per minute. Estimates of the numbers of minutes per occurrence was from time and motion studies done in 1999, which no longer may be accurate due to gains in efficiency over time due to improved technology and business practices. In addition, model error is introduced by relying on many parameters that can be hard to estimate accurately.
- Separating the Customer Classes Out: For example, in PG&E's 2014 GRC RCS Model, the residential and small commercial classes are combined to determine the per-customer cost of providing automatic payment plans. This is potentially in correct since it could be residential customers that primarily use automatic payment plans and not small commercial customers. The 2017 GRC RCS Model avoids this issue by using a cost driver that measures each class's usage of each activity. Grouping classes together is less accurate because in reality, there can often be significant cost differences in providing billing and payment activities depending on a customer's size, service voltage, or other service requirements.
- Including "Other Account 903" Costs in the Underlying Financial Cost Data Instead of Using Estimates of These Costs: In the 2014 GRC Phase II filing, PG&E conducted a survey of subject matter experts to derive estimates of the portion of "Other Account 903" ongoing customer service costs included in GRC Phase I that were marginal. These surveys were required because the RCS model used at the time had not been revised to included activities for ongoing customer access costs that had been added or expanded since the RCS activities had last been updated. The Other Account 903 costs not captured in previous RCS models, now included in the current model, include electric safety and

reliability outreach, local office and neighborhood payment center transactions, development of pay channel options for customers, customer account services, customer research, planning and product development, escalated complaint management, load research, and other customer outreach and education.

  – Using Actual 2014 Customer Counts Instead of Forecasted 2014 Customer Counts to Determine the Marginal Costs for Metering Reading and Meter Services: In its 2014 GRC Phase II filing, PG&E used forecasted 2014 customer counts for these activities since PG&E's investment in a SmartMeter™ infrastructure had not been completed by the time of the filing.

- Improved Segmentation and Accuracy by Being Able to Calculate Marginal RCS Costs at the Rate Schedule Level: By using cost data tied to rate schedule and customer classes, the new RCS results better reflect cost causation and rate fairness, two guiding principles for ratemaking. In addition, the increased segmentation supports analysis of customer charges.
- Improved Transparency Into RCS Calculations: All calculations are now in a single Excel workbook with a structured format. In addition, thorough model documentation details the methodology and fully describes the financial cost data and cost drivers.

D. Comparison of Results With 2014 GRC Phase II RCS Results

Table 8-1 below compares the 2017 class-level RCS results with the 2014 class-level RCS results.

TABLE 8-1
COMPARISON OF 2017 RCS RESULTS WITH 2014 RCS RESULTS[(a)]

Line No.	Class	2014 Results (2014 $)	2017 Results (2014 $)	Difference
1	Residential	$40.52	$38.26	$(1.39)
2	Small L&P	$77.60	$134.77	$56.95
3	A10 Medium L&P Secondary	$278.57	$230.94	$(49.67)
4	A10 Medium L&P Primary	$720.33	$1,138.77	$365.59
5	E19 Secondary	$516.27	$1,467.95	$809.81
6	E19 Primary	$1,012.82	$2,174.76	$938.60
7	E19 Transmission	$1,383.44	$3,465.90	$1,830.78
8	E20 Secondary	$1,312.98	$1,994.42	$306.89
9	E20 Primary	$1,412.08	$2,598.94	$867.86
10	E20 Transmission	$1,383.44	$4,547.69	$2,778.06
11	Agricultural A	$119.86	$121.18	$1.40
12	Agricultural B	$161.46	$497.72	$338.03
13	Streetlights	$64.56	$114.07	$47.98
14	Traffic Control	$77.60	$151.78	$63.80

(a) The costs for E-19 voluntary customers are included in the A-10 class for 2017 but were included in the E-19 class for 2014.

The magnitudes of the 2017 class-level RCS results between customer classes are in general agreement with the size of customers that generally make up each customer class; that is, the larger the customer the higher the RCS costs. Some of the customers on Schedules A-10, E-19 and E-20 are handled by the Customer Care and Billing (CC&B) Department, which is responsible for billing customers that cannot be billed in the standard way through the CC&B system due to the sheer size and/or complexity of their billing contracts. In addition, many Agricultural, A-10, E-19 and E-20 customers have many meters that are still read manually, either because they still have non-SmartMeter™ devices or SmartMeter™ devices that are too remote to be digitally read. Also, customers in these classes tend to have their meters replaced more often than Residential or Small Light and Power customers. Compared to the 2014 class-level RCS results, the 2017 class-level RCS results are higher and show more spread between the classes. This is due to two main reasons:

- Actual cost data are used which inherently incorporate the frequency and usage of the activities, whereas the model used in the 2014 GRC filing used estimates from out dated time and motion studies; and
- Activities are no longer combined for Commercial, Industrial and Agricultural classes.

E. Background

As a consequence of Electric Industry Restructuring (EIR) in the 1990s and the unbundling of billing and meter services, PG&E developed activity-based costing models (RCS models) to accurately estimate the rate credits for when these services were competitively provided by Electric Service Providers. Such RCS models provided a very detailed analysis of the individual activities that comprised a service, such as meter reading, and enabled PG&E to separate the fixed cost from the marginal cost of providing that service. In addition, these models allowed PG&E to analyze the savings it expected when its distribution customers had services performed by entities other than PG&E. Before the advent of EIR, PG&E did not have the necessary data to perform a separate marginal cost analysis for these ongoing costs. Instead, PG&E estimated its average cost per customer for ongoing customer services and used this average cost as a proxy for the marginal cost.

PG&E developed its first RCS models for use in the RCS proceeding (Application (A.) 97-11-004) to estimate avoided costs when customers switched to alternate RCS providers. In the RCS Decision (D.98-09-070),[1] the CPUC ordered that credits from these models be based on short-run avoided costs. In that decision, the CPUC also ordered PG&E to compute long-run avoided costs ("or a reasonable proxy").

In its 2003 GRC Phase II filing, PG&E adopted the long-run approach for determining marginal ongoing cost component of marginal customer access costs. In addition, PG&E updated the activities in the RCS models it had used for the RCS proceeding (A.97-11-004) to reflect changes in billing and payment processing services and also updated the labor rates used in the prior models. PG&E also proposed to use a survey methodology to estimate the portion of marginal ongoing customer access costs not covered by the RCS models. These costs are referred to as Other Account 903 costs since they are recorded in Federal Energy Regulatory Commission Account 903. Other Account 903 costs include, for example, the costs of local office and neighborhood payment center transactions.

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[1] See D.98-09-070, mimeo, p. 29, Ordering Paragraph 7.

In its 2014 GRC Phase II filing, PG&E significantly revised the meter services and meter reading components of the RCS models due to the implementation of PG&E's SmartMeter™ Program, which resulted in a major change in technology and associated costs. PG&E also updated its Other Account 903 costs based on a survey of subject matter experts.

Lastly, PG&E's GRC Phase II proceedings that included an RCS model did not make a litigated result, as all of PG&E's GRC Phase II proceedings for the past 15 years have been settled with no express adoption of an RCS model for the development of marginal costs.

F. Conclusion

PG&E's RCS model introduced in this filing is a significant improvement over the data and methodology used in the past, and the longer-run marginal ongoing customer access costs determined with it are more accurate. In addition, PG&E's improved RCS model is thoroughly documented to delineate its specific datasets, calculations and assumptions. The new RCS model produces numbers that are more granular than previous RCS models, resulting in more cost-based rates.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 9

GENERATION PCAF ANALYSIS

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CHAPTER 9
GENERATION PCAF ANALYSIS

A. Introduction

This chapter describes Pacific Gas and Electric Company's (PG&E) methodology for calculation of generation Peak Capacity Allocation Factors (PCAF) which are used to compute generation PCAF-weighted loads for different customer classes. Generation PCAF-weighted loads are measures of coincident loads of different customer classes with reference to the system load which are utilized to allocate cost responsibility of marginal generation capacity costs among various customer classes. In more technical terms, generation PCAF-weighted loads are used to determine the Equal Percentage of Marginal Cost (EPMC) allocators across all bundled customer classes. EPMC allocators are then used to allocate generation capacity costs across these customer classes in marginal cost revenue allocation and eventually, generation capacity revenue allocation among different customer classes.

B. Background

PCAF-weighted load methodology was first adopted by the California Public Utilities Commission (CPUC or Commission) in PG&E's 1993 General Rate Case (GRC) (D.92 12 057, pp. 290-291, p. 303; D.93-06-087, pp. 47-48, pp. 54-55, and pp. 75-76). This method has been used to develop the company's distribution marginal cost and revenue allocation showings in each of its subsequent GRC Phase II proceedings. In each subsequent GRC Phase II, PG&E has always updated the load models by incorporating the available load research data, while making refinements and improvements to the models over time (both on its own initiative, and/or in response to inputs and suggestions from the Office of Ratepayer Advocates staff and other interested parties). PG&E first extended its PCAF methodology to develop system-level PCAFs for generation-level marginal costs in its 2003 GRC Phase II proceeding. PG&E uses the same PCAF concept of peak responsibility as it does for the Commission-approved AREALOAD-based PCAF concept of peak responsibility for the distribution level.

C. Methodology

Calculation of generation PCAF-weighted loads for different customer classes is performed in following steps:

1) **Identifying the PCAF hours:** Generation PCAF hours are the hours during which the total system load is above 80 percent of the system maximum load during the calendar year. If more than 800 of the hourly loads are within 80 percent of the maximum load, then the 800 largest loads are chosen as PCAF hours. However, if fewer than 10 hourly loads are within 80 percent of the system maximum load then the 10 largest loads are chosen.

2) **Assigning appropriate weights to the identified PCAF hours in Step 1:** For each identified PCAF hour *i* in the previous step, the corresponding PCAF weight (w_i) is calculated using the following formula:

$$w_i = \frac{L_i - TL}{\sum_{i=1}^{N}(L_i - TL)}$$

Where:

- L_i: System load at PCAF hour *i*,
- *N*: The total number of identified PCAF hours,
- *TL*: 80% of system maximum load. If less than 10 PCAF hours are identified in Step 1, *TL* is the 11th largest system load.

3) **Calculating Generation PCAF-weighted load for each customer class:** Generation PCAF-weighted load for each customer class is calculated as the weighted sum of the corresponding customer class

gross load curve at the identified PCAF hours in Step 1 by their corresponding PCAF weights calculated in Step 2.[1]

D. Illustration of Data

Starting with the 1996 case, PG&E extended the original PCAF methodology to incorporate data from three historic years of load research data for all customer classes. This change was made in response to recommendations from Division of Ratepayer Advocates staff in the 1993 case, and the company believes this refinement has substantively improved all of its subsequent load estimates. Also, as it was stated earlier, in its 2003 GRC Phase II showings, PG&E extended its original methodology to include development of generation-level PCAFs for the first time. PG&E's 2007 Phase II showings included the following improvements and refinements: (1) PG&E adjusted downward its winter loads relative to summer loads, in recognition of the fact that substation transformers have greater capacity in cooler temperatures than in hotter temperatures;[2] (2) PG&E improved its PCAF-weighting scheme for loads that have less than 10 hours of peak load in a calendar year; and (3) PG&E simplified and improved the weather-normalization process. For 2014 GRC Phase II proceeding, PG&E updated its load data to include the years 2009, 2010, and 2011. Most significantly, for the load research data from calendar year 2011, PG&E was able to increase the load research sample sizes used for almost every customer class (by factors of between 3 and 10, depending on class) using data made available by the installation of SmartMeters™.

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1 Because of availability of total system load profile and aggregated customer class loads in a more granular level (e.g., 15-minute intervals) in the current filing, we expanded the PCAF concept at hourly level to define PCAF at interval level to generate more accurate PCAF weighted loads. This means that instead of identifying peak capacity allocation factor hours, assigning weights for each PCAF hour and calculating the corresponding PCAF-weighted load for each customer class, we performed these calculations (Steps 1-3) at interval level. For example, in Step 1, generation PCAF intervals are defined as intervals during which the total system load is above 80 percent of the system maximum load during the calendar year. If more than 3200 of the 15-minute interval loads are within 80 percent of the maximum load, then the 3200 largest loads are chosen as PCAF hours.

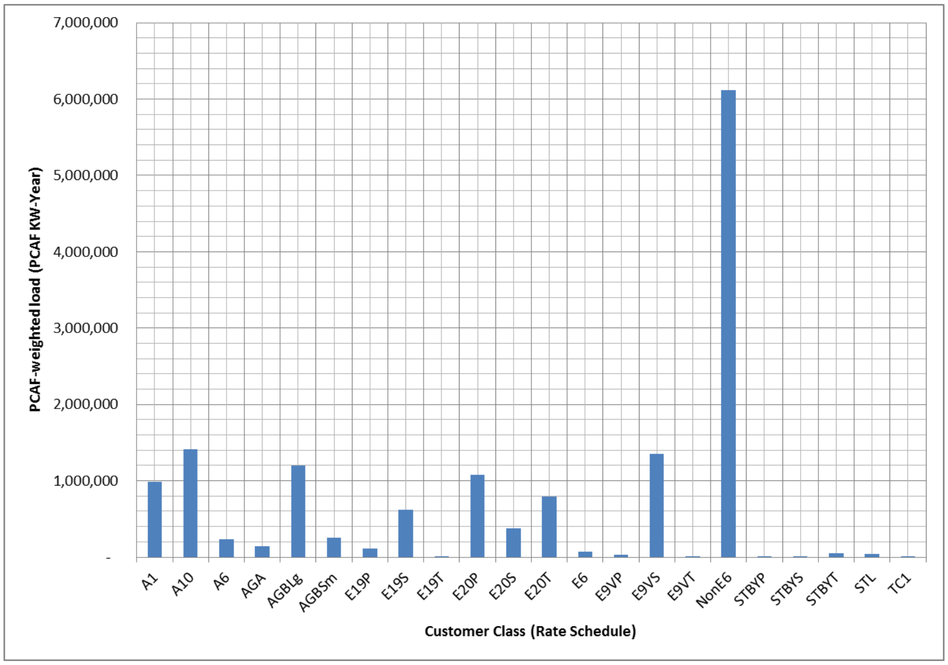
2 Please note that this improvement is applicable to PCAF-weighted loads at distribution level which is the subject of next chapter and does not apply to calculated generation level PCAF-weighted loads.

In the current filing for 2017 GRC Phase II and to better address the impacts of incremental distributed generation and energy efficiency programs on customers load profiles, the following improvement have been included:

1) Instead of using system-level gross load (which was the practice in earlier GRCs), hourly adjusted net loads (ANL) are used to identify the PCAF hours and their corresponding weights. ANL is defined as the gross load minus the renewable (solar and wind), hydro and nuclear generation resources. ANL represents marginal generation costs better than gross load since it excludes most of the must-take generations. California Independent System Operator's (CAISO) forecasted hourly ANLs for the year 2017 (the test year for 2017 GRC Phase II filing) are used for generation PCAF analysis.
2) Historical customer class hourly net metered loads for the year 2014 are used to calculate the generation PCAF-weighted loads for each customer class. This means that for net energy metered customers (NEM customers), their corresponding net loads in the 2014 calendar year is considered in the calculations. In 2014 GRC Phase II filing, PG&E used the 3-year average load data (2009, 2010 and 2011) to calculate the generation PCAF-weighted loads. However, to better reflect the increasing number of net energy metering (NEM) customers in each year, PG&E decided to use the most recent available customer loads in the current filing. This enhancement would take into consideration the most recent information available and hence would most reasonably reflect the evolution of NEM customers in the market.

Calculated generation level PCAF-weighed loads for different customer classes (rate schedules) used in 2017 GRC Phase II, are shown in Figure 9-1.

FIGURE 9-1
GENERATION LEVEL PCAF-WEIGHED LOADS USED IN 2017 GRC PHASE II



E. Conclusion

In this chapter, PG&E's methodology for calculating Generation PCAF-weighted loads was explained. Generation PCAF-weighted loads as measures of coincident loads of different customer classes with reference to the system load are utilized to allocate cost responsibility of marginal generation capacity costs among various customer classes. PG&E's enhancements to generation PCAF analysis compared to previous GRC filings include:

1) Utilizing California ISO's forecasted hourly adjusted net loads for the year 2017 in identifying the PCAF hours and calculating their corresponding weights to better address the marginal generation costs.
2) Using customer class net metered loads for the year 2014 to calculate PCAF-weighted loads for each customer class. The reason for using 2014 year data is because it would take into consideration the most recent information available and hence would most reasonably reflect the evolution of NEM customers in the market.
3) Because of availability of total system load profile and aggregated customer class loads in a more granular level (15-minute intervals) in the current filing, we expanded the PCAF concept at hourly level to define PCAF at interval level to generate more accurate PCAF weighted loads.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 10

DISTRIBUTION PCAF ANALYSIS

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A. Introduction

This chapter describes Pacific Gas and Electric Company's (PG&E or the Company) methodology for calculation of distribution Peak Capacity Allocation Factors (PCAF). Distribution PCAF-weighted loads are indicative of the stresses placed on area facilities at and near the time of the peak loads in the division level area. The higher ranked the division hourly load, the greater the PCAF-weighted load assigned to that division.

After developing customer diversified load estimates for PG&E's distribution divisions, they are used to develop the distribution level PCAF-weighted loads. The diversified load is equal to each customer group's contribution to each of the division peak hours. Division PCAF-weighted loads provide a means of assigning greatest weight to those hours when loads in the division are at or near their annual peak, and local distribution capacity limits are closest to being reached. Hence, they are appropriate to use with marginal costs incurred for facilities most affected by peak loads within the division. Such facilities are usually in the vicinity of substations where power flows first enter the division. The division PCAF-weighted load is a weighted average summation of the calendar year's hourly loads, with the greatest weights being assigned to those days and hours when loads are at their highest levels.

B. Background

Conceptually, the PCAF-weighted load of a customer class is somewhat like the coincident division-level peak demand of the class in that division, except that the coincidence is measured not only over the single peak hour of the year, but over a number of the highest load hours in that division, since each of these hours have some degree of likelihood, some more than others, of being the division peak load hour in the test year. As it was explained in Chapter 9, PCAF-weighted load methodology was first adopted by the California Public Utilities Commission (CPUC or Commission) in PG&E's 1993 General Rate Case (GRC) (D.92-12-057 47 CPUC 2d 143 (1992), pp. 290-291, p. 303; D.93-06-087, 50 CPUC 2d 1 (1993) pp. 47-48, pp. 54-55, and pp. 75-76). This method has been used to develop the Company’s distribution marginal cost and revenue allocation showings in each of its subsequent GRC Phase II proceedings. In each subsequent GRC Phase II, PG&E has always updated the load models by incorporating the available load research data, while making refinements and improvements to the models over time (both on its own initiative, and/or in response to inputs and suggestions from the Office of Ratepayer Advocates staff and other interested parties).

C. Methodology

Distribution PCAFs are defined for each geographic division within PG&E’s service territory and are calculated for each customer class in a similar way to generation PCAFs with the following distinctions:[1]

a) Division-level hourly loads are used to identify and calculate the PCAF hours and their corresponding weights for each division.

b) Division-level distribution PCAF for each customer class are then calculated by:

   i. Summing the product of the division-level hourly loads of that particular customer class and the corresponding PCAF weights.

   ii. Dividing the result from the previous step by the PCAF weighted sum of division-level hourly loads and then multiplying it by the maximum load of the corresponding division.

Division-level hourly loads are used to identify and calculate the PCAF hours and their corresponding weights for each division and customer class.[2] For 2017 GRC Phase II, historical customer class hourly delivered metered loads for the year 2014 are used to calculate the distribution PCAF-weighted loads for each customer class within each division (19 divisions in total). In 2014 GRC Phase II filing, PG&E used the 3-year average load data (2009, 2010 and 2011)

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1 As it was mentioned in Chapter 9, starting from 2007 Phase II showings, for distribution PCAF-weighted load calculations, PG&E adjusted downward its winter loads relative to summer loads, in recognition of the fact that substation transformers have greater capacity in cooler temperatures than in hotter temperatures.

2 Because of availability of load profiles and aggregated customer class loads in a more granular level (15-minute intervals) in the current filing, similar to generation PCAF-weighted load calculations explained in Chapter 9, we expanded the PCAF concept at hourly level to define PCAF at interval level to generate more accurate PCAF-weighted loads.

to calculate the distribution PCAF-weighted loads. However, to better reflect the increasing number of Net Energy Metering (NEM) customers in each year, PG&E decided to use the most recent available customer loads in the current filing. This enhancement would take into consideration the most recent information available and hence would most reasonably reflect the evolution of NEM customers in the market. It should be emphasized that for distribution PCAF analysis, *delivered* metered loads of the year 2014 are used. However, for generation PCAF-weighted loads calculations on Chapter 9, net metered loads of the year 2014 were used. The reason is *delivered* metered loads better reflect the stress imposed on PG&E's distribution circuits since distributed energy resources (net metered customers) are of intermittent nature and it is required to consider the extreme conditions on PG&E's distribution circuits.

D. Conclusion

PG&E's approach to determining customer class contribution to distribution system peaks is largely unchanged from prior GRCs. Distribution PCAF-weighted loads are used to measure stresses placed on area facilities at and near the time of the peak loads in the division level area. The higher ranked the division hourly load, the greater the PCAF-weighted load assigned to that division. PG&E's enhancements to calculate distribution PCAF-weighted loads compared to previous GRC filings include:

1) Using customer class delivered metered loads for the year 2014 to calculate PCAF-weighted loads for each customer class at each division. The reason for using 2014 year data is because it would take into consideration the most recent information available and hence would most reasonably reflect the evolution of NEM customers in the market.
2) Because of availability of load profile and aggregated customer class loads in a more granular level (15-minute intervals) in the current filing, we expanded the PCAF concept at hourly level to define PCAF at interval level to generate more accurate PCAF weighted loads.

PG&E requests the Commission to adopt this approach for use in determining marginal cost revenue and revenue allocation and rate design.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 11

FINAL LINE TRANSFORMER LOAD ANALYSIS

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FINAL LINE TRANSFORMER LOAD ANALYSIS

A. Introduction

In this chapter, Pacific Gas and Electric Company (PG&E) requests that the California Public Utilities Commission (CPUC or Commission) approve its methodology to calculate final line transformer (FLT) loads. FLT loads are the peak loads at the FLTs. FLT loads are multiplied by the New Business on Primary Marginal Distribution Capacity Cost and the Secondary Marginal Distribution Capacity Cost in order to determine marginal distribution capacity cost revenue for these costs. Marginal cost revenue is then used in revenue allocation and rate design.

B. Background

Since its 1996 General Rate Case (GRC) Phase II, PG&E has made efforts to improve its estimation methodology of FLT loads. In the 2007 GRC Phase II filing, PG&E made the following improvements:

1) PG&E reduced winter loads relative to summer loads in recognition of the fact that substation transformers have greater capacity in cooler temperatures than in hotter temperatures. The degree of load adjustment used varied depending on whether the customer was in a coastal division or an interior division, since the contrast between winter and summer temperatures is greater in interior divisions than for coastal divisions.

2) PG&E improved how its FLT load determination method estimates the FLT load diversity for the residential and small commercial class customers, even as its FLT load determination method is otherwise the same as that adopted by the CPUC in its 1993 GRC Phase II. Specifically, this change utilizes a different method of determining the average number of customers sharing a FLT. The number of customers sharing a FLT is relevant because it determines the degree of load diversity. Instead of calculating the average number of customers sharing the most typical size transformer in each service territory region, as was done previously, the average number of customers for all FLT sizes in each region was calculated. This refinement

increases the accuracy of the FLT load diversity factor estimates because it reflects more data than in the previous method.

For 2014 GRC Phase II proceeding, PG&E updated its load data to include the years 2009, 2010, and 2011. Most significantly, PG&E was able to increase the load research sample sizes used for almost every customer class using data made available by the installation of SmartMeter™ devices. Lastly, for this proceeding, PG&E proposes to use delivered loads instead of net loads and only one year of data, 2014, rather than three years of data, 2012, 2013 and 2014.

C. Methodology

A significant number of customers in PG&E's service territory have their own generation systems. In particular, many residential customers own solar panels. As a result, PG&E not only delivers but also receives load from these customers. As with distribution PCAFs (see Chapter 10 of this exhibit), PG&E proposes to use delivered metered loads instead of net metered loads (delivered loads minus received loads) to calculate FLT loads. This is appropriate since distribution facilities must have the capability to accommodate the delivered loads and not the net loads. Furthermore, in the event a customer's generation system is not operating, PG&E is still required to deliver energy to the customer and so delivered loads are better proxy of a customer's energy demands. PG&E proposes to use only 2014 data rather than 2012, 2013 and 2014 data because 2014 data takes into consideration the most recent information available about the evolution of customers in PG&E service territory. For large customers,[1] the interval data is for every customer. For small customers,[2] the interval data is for a sample of customers. Calculation of FLT loads for the customer classes is performed in the following steps:

1) **Calculate Non-Coincident Demand:** For each customer in the data, take the recorded load during the 15-minute or 60-minute interval that has the highest recorded load out of all 15-minute or 60-minute intervals for the year. This is a customer's maximum non-coincident demand. Next the

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1 Large customers are customers on rate schedules A-10, E-19, E-19 Voluntary, E-20, E-37 or the B, C, E and F options of rate schedules AG-4, AG-5, AG-R and AG-V.

2 Small customers are customers on rate schedules A1, A6, any Residential schedule or the A and D options of rate schedules AG-1, AG-4, AG-5, AG-R and AG-V.

maximum non-coincident demands are summed by customer class and division. Lastly, if a sample is utilized, the total demands for each customer class and division are scaled to the population. In the past, three years of recorded data were averaged to produce an average non-coincident demand.

2) **Apply Diversity Adjustment:** Customers in the residential and small commercial customer classes often share a single FLT. Hence, the peak load on the FLT will tend to be less than the sum of the maximum non-coincident loads of the customers that share the FLT, since the customers maximum demands can occur at different times. Such a group load is referred to as a diversified load. To account for this, a diversity adjustment factor is applied to the demands from Step 1 for the residential and small commercial classes. Customers in the larger classes are assumed to have their own dedicated FLT; thus, a diversity adjustment factor is not applied.

D. Illustrative Data and Example

The table below is an example of the interval data for a hypothetical E1 customer.

TABLE 11-1
CUSTOMER INTERVAL LOADS

Line No.	Cust ID	Day	Davison	Class	kW1	kW2	kW24
1	1	1	Central Coast	E1	12.56	11.23	13.39
2	1	2	Central Coast	E1	11.52	13.55	14.28
3	1	365	Central Coast	E1	21.92	18.24	16.59

The maximum non-coincident demand for this customer is 21.92 kilowatts (assuming the loads not shown are all less). This customer belongs to the Central Coast division and is in the residential customer class. Suppose that the sum of the maximum non-coincident demands for all residential customers located in the Central Coast division is 100,000 kilowatt-hours (kWh) and that the ratio of the number of customers in the sample to the number of customers in the population is 1:10. The estimated population maximum non-coincident demand is then 1,000,000 kWh. Finally, if the diversity factor for residential customers in the Central Coast division is 0.5, the FLT load is 1,000,000 kWh x 0.5 = 500,000 kWh.

E. Conclusion

PG&E uses the same methods to calculate FLT demand as it has used in previous proceedings, except as explained above, PG&E uses delivered loads instead of net loads and only 2014 data rather than a three year average. PG&E respectfully requests that the Commission approve PG&E's methodology for developing FLT loads.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 12

OPTIMAL NON-RESIDENTIAL TOU PERIOD ANALYSIS

PACIFIC GAS AND ELECTRIC COMPANY
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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 12
OPTIMAL NON-RESIDENTIAL TOU PERIOD ANALYSIS

A. Introduction

The purpose of this chapter is to describe Pacific Gas and Electric Company's (PG&E) methodology for defining the new Time-of-Use (TOU) peak period(s) it is proposing for its non-residential customers' TOU rates, to establish a peak period that more efficiently captures the high marginal generation cost hours, and which would be appropriate for at least the next five years. The methodology described in this chapter is similar to the methodology PG&E presented in its 2015 Rate Design Window (RDW) proceeding. The California Public Utilities Commission (CPUC or the Commission) adopted new residential TOU periods that, for the first time, shifted the weekday peak period significantly later in the day based on the extensive record in that proceeding.[1] PG&E is not proposing to modify its residential TOU periods in this filing because the CPUC only six months ago adopted a Settlement that included multi-year residential TOU rates, which was decided after taking into account the hourly shape of the generation marginal costs as well as residential customer preference considerations.

PG&E's proposals here take into consideration the information gained thus far through the CPUC's TOU Periods Order Instituting Rulemaking (R.15-12-012), including data provided by the California Independent System Operator (CAISO) and the evolving principles being developed there. In addition, PG&E's proposals here are also informed by insights PG&E has gained thus far through Commissioner Sandoval's Energy Matinee Pricing Pilot proceeding (R.13-12-011), focusing on testing spring season super-off peak hours in non-residential TOU rates, in an effort to address periods of over-generation which can cause negative generation pricing due to strong

[1] For example, the peak hours adopted for the E-TOU-B rate were 4 p.m. – 9 p.m., based on independent cost-analyses by both PG&E and Office of Ratepayer Advocates' consultant, Synapse, that both reached this conclusion. The results in this 2017 General Rate Case (GRC) proposal for non-residential TOU peak periods are based on MGCs derived using an extra year of data, through April 2016, and supports a 5 p.m. – 10 p.m. peak period.

hydro runoff combined with must-take solar generation, warranting consideration of ways to get customers to use more energy during those mid-day hours.

B. Overview

PG&E proposes that two factors should be used to determine TOU periods: (1) marginal costs; and (2) customer considerations.

1. TOU Periods Should Be Cost-Based

The first and most fundamental principle in determining TOU periods is that they must be cost-based. PG&E continues to propose that TOU periods be based on an analysis of Marginal Generation Costs[2] to align the peak period hours with the highest cost hours.

In addition, for the first time, PG&E also considers here marginal distribution costs by using the distribution demand data. In particular, PG&E considers the hours during which distribution demand is very high in their respective locations (i.e., divisions) which PG&E uses here solely as part of determining the appropriate summer partial-peak hours. Distribution peak hours generally align very well with the generation peak hours, but are spread across more hours of the day. Hence, using distribution demand data (in addition to the generation marginal costs) for determining partial-peak period is appropriate.

The price signals sent to customers through properly aligned TOU peak periods incent customers to shift their loads away from those high cost hours and into lower cost hours, in response to actual marginal costs. This results in reduced overall system costs from customers shifting more usage into lower cost periods and making better use of lower-cost system generation resources. Focusing primarily on ensuring that TOU periods are cost-based is consistent with the fundamental principle of rate design that rates that are more aligned with cost-causation can encourage reduction of peak demand. If TOU peak periods were not set to cover and align with the

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2 As discussed in detail in Chapter 2 of this exhibit, Marginal Generation Costs (MGC) (which is the sum of Marginal Energy Costs, and Marginal Generation Capacity Costs) are generally consistent with Adjusted Net Load data. Although the Net Load data (included in the CAISO's Report in the TOU Periods OIR) is a decent proxy for MGC, PG&E's Adjusted Net Load (that also excludes base-load serving nuclear and hydro that is largely non-curtailable) is an even better proxy for PG&E's MGCs, as it fits the cost data even better.

highest cost hours (and thus non-peak periods were set so as to include some hours that are actually higher cost hours), customers would be shifting load to the wrong times. This would cause all customers to see increased costs from greater than necessary procurement during higher cost times, because high demand hours that should not have been included in the non-peak period were included there instead of in the peak period, thus sending lower-than-appropriate peak period price signals and causing increased demand when in fact load shifting away from those hours is what is needed to support more optimal system operations and lower costs.

2. Customer Considerations May Be Used to Refine TOU Periods, Especially for Optional Rates, While Remaining Aligned With Cost-Basis

As a secondary consideration, available information on customer preferences, such as survey findings, can be used to determine whether modest amendments to the cost-based results might be warranted to refine the final TOU rate design and TOU period recommendations, while still aligning with cost data. Such considerations might include creating rates that are more appealing or easier to understand such as fewer hours, fewer periods and consistency across seasons. For example, customer considerations might warrant the creation of an optional TOU rate with a shorter total number of peak hours, if some customers indicated that they could more easily adjust their operations to a shorter peak period. However, in such instances, PG&E would still recommend aligning the peak period with the highest cost subset of that range of potential peak hours.

C. Use of 2020 Forecast of Marginal Generation Costs

PG&E's analysis of TOU periods uses as its primary input the forecasted 2020 hourly Marginal Generation Costs derived using the model described in Chapter 2 of this exhibit. This data was used to determine the hours during the day when the highest MGCs occur. This chapter describes how PG&E used these hourly marginal generation costs to develop the 5 p.m. – 10 p.m. peak period that PG&E is proposing for non-residential rates in this application. PG&E's use of MGCs forecasted out to 2020 is appropriate here because most changes in PG&E's renewable energy supply are driven by the regulatory mandate of 33 percent Renewables Portfolio Standard (RPS) that is expected to have occurred by 2020. Indeed, PG&E has already achieved an RPS level of almost 30 percent as of 2015. The effect of significant solar RPS uptake—which has driven the shift of high cost MGC hours to much later in the day (5 p.m. – 10 p.m. for PG&E as of 2020)—is not likely to change significantly for some time after 2020. This is because whether additional RPS uptake after 2020 is chiefly solar or some other technology(s), the beginning of the peak period will be most strongly influenced by the ramp-down of solar generation, and (unless AB 385 goes into law) the times the sun sets will not change. Thus, PG&E's proposed 5 p.m. – 10 p.m. peak period, based on 2020 forecast horizon supports the goal of adopting a peak period that would be appropriate until at least five years from now.[3] PG&E's proposal here differs slightly from the peak period identified in the CAISO's January 22, 2016 TOU Periods Report, submitted in the TOU Periods OIR proceeding (R.15-12-012)—which identified a 4 p.m. – 9 p.m. peak, based on data through 2014-2021.

However, CAISO stated in its Report that PG&E's peak is one hour later than the other two investor-owned utilities' (IOU) peak, so PG&E's proposal is not in conflict with the CAISO's identical peak period.[4] To illustrate how the magnitude of the forecast hourly Marginal Generation Costs varies over the hours in 2020, PG&E presents a heat map in Figure 12-1, below.

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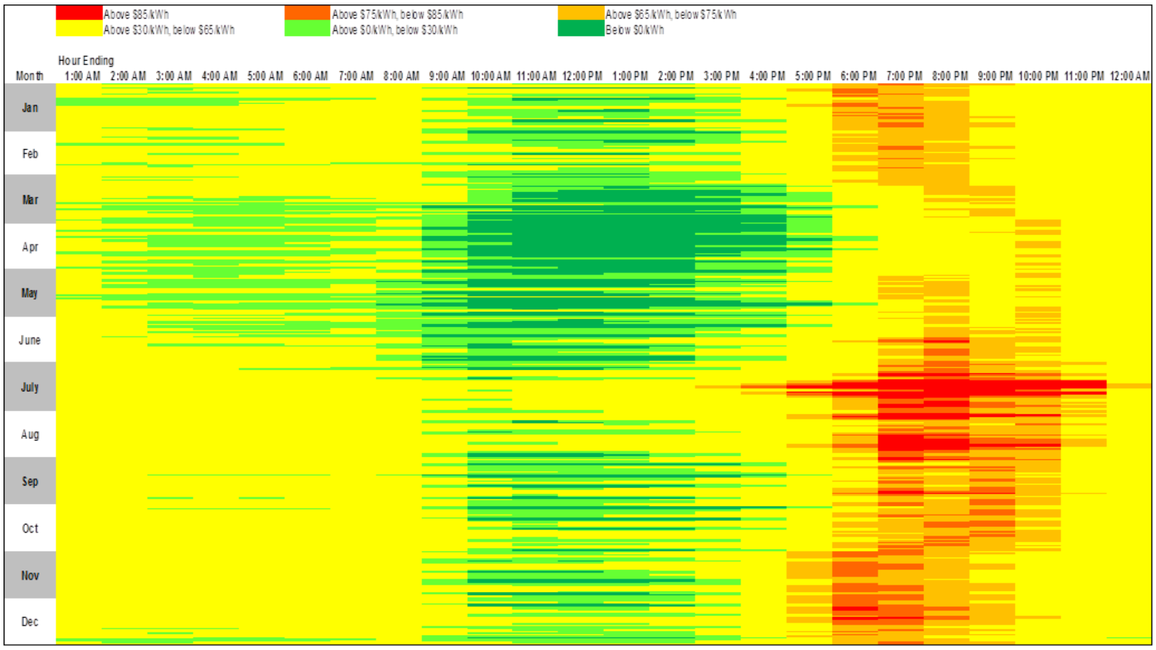
3 The non-residential rates adopted in this proceeding are expected to be in effect from 2018-2020, with PG&E's next GRC expected to go into effect either in 2021 or 2022.

4 "The CAISO's coincident peak aligns well with the individual IOU peaks across all seasons except for PG&E, which peaks an hour later than the CAISO during the summer," page 14, CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION EXPLANATION OF DATA, ASSUMPTIONS AND ANALYTICAL METHODS, January 22, 2016. PG&E believes that the charts referenced by the CAISO also support the assertion that PG&E's peak load occurs an hour later than the other IOUs in the fall.

FIGURE 12-1
HOURLY MARGINAL GENERATION COST ACROSS THE HOURS IN THE YEAR 2020



D. Overview of PG&E's TOU Period Analysis and Proposals

PG&E used a five-step process to determine the TOU periods proposed for use in non-residential rates in this proceeding.

The first step is to determine the seasons. To do this, PG&E reviewed how the highest marginal generation cost hours were distributed across the year to determine the months that should be designated as summer months.[5] By counting the number of high cost hours each month, PG&E determined that the months June through September capture most of the highest-cost hours. (See detailed discussion in Section F below)

The second step is to determine the highest cost hours. PG&E studied the highest-cost hours during each day, and determined that the highest cost hours are now generally concentrated during the period from 5 p.m. – 10 p.m. (See detailed discussion in Section G below.)

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5 PG&E has analyzed the highest cost hours by considering two scenarios: (1) top 100 cost hours; and (2) top 250 cost hours of a calendar year. The remaining hours are called low cost hours. The analysis to determine summer months referred here is limited to defining TOU periods only, and does not necessarily call for making any changes to the season definition for purposes such as baseline quantity.

The third step is to select the optimal, cost-based range of hours. To do this, PG&E evaluated numerous TOU period scenarios to determine which scenario's peak period definition would most efficiently maximize the number of highest cost hours in the peak period and minimize the number of low-cost hours in the peak period.

Fourth, PG&E needed to analyze the summer partial-peak period hours, as well as the hours for a potential super off-peak period occurring in March, April and May. For the summer partial-peak analysis, PG&E used Distribution demand data in addition to MGC data. (See detailed discussions of these additional analyses in Sections I and L of this chapter).

Fifth and finally, PG&E analyzed whether the peak period should include weekends and holidays, as well as weekdays (Section J). PG&E concluded that the proposed non-residential TOU peak period of 5 p.m. – 10 p.m. should be consistent and apply during all days of the week and in all seasons.

As for the existing TOU periods for PG&E's non-residential customers, these TOU periods used in PG&E's non-residential TOU rates were set many years ago and have not been updated for a long time. PG&E presents below a comparison of a representative non-residential TOU rate to its proposed new TOU period hours and seasons:

TABLE 12-1
COMPARISON OF EXISTING TO PROPOSED TOU PERIODS AND SEASONS

Line No.		PG&E's Existing Non-Residential TOU (Based on Schedule A1/A6/A10)	Proposed Non-Residential TOU	PG&E's Recently-Adopted Residential Schedule E-TOU-B
1	Summer Season	May – October	June- September	June - September
2	TOU Summer Peak	Noon – 6 p.m. *(M-F, non-holidays)*	5 p.m. – 10 p.m. All days of week	4 p.m. – 9 p.m. (M-F, non-holidays)
3	TOU Summer Partial Peak	8:30 a.m. – noon *and* 6 p.m. – 9:30 p.m. *(M-F, non-holidays)*	3 p.m. – 5 p.m. 10 p.m. – 12 p.m. All days of week	N/A (to keep res TOU rates simpler and more understandable)
4	TOU Summer Off-Peak	All other hours	All other hours	All other hours
5	Winter Peak (Currently Called Partial Peak)	8:30 a.m. – 9:30 p.m. *(M-F, non-holidays)*	5 p.m. – 10 p.m. All days of week	4 p.m. – 9 p.m. (M-F, non-holidays)
6	Winter Off-Peak	All other hours	All other hours	All other hours
7	Super Off- Peak	None	10 a.m. – 3 p.m. *(March-May, All days of the week)*[a]	None (to keep res TOU rates simpler and more understandable)

(a) PG&E seeks to test a similar super-off-peak period through its non-residential Energy Matinee Pricing Pilot proposal, as set forth in its February 4, 2016 filing in that proceeding. The pilot launch is targeted for spring 2017, assuming PG&E receives a timely decision, and the pilot is intended to run for two spring seasons, with results issued several months after the pilot ends (by the end of 2018).

E. Methodology to Determine Seasons, Peak and Non-Peak TOU Hours

The MGC results from Chapter 2 of this exhibit support shifting PG&E's peak periods to later in the day (5 p.m. – 10 p.m.), as discussed herein. In order to provide accurate price signals and incentivize for appropriate load shifting, the peak period needs to be appropriately defined so as to capture a high percentage of the highest cost hours, while simultaneously excluding the lowest cost hours as much as possible. Before deciding on a specific peak period definition to propose, PG&E evaluated a large number of candidate definitions, as described in the next several paragraphs. To do this, PG&E first built a model to evaluate high and low MGC hours (MGC is defined as the sum of hourly forecasted energy and capacity costs in 2020). PG&E's model is defined by the following criteria: (1) timeframe for the analysis period; (2) a threshold for number of high cost hours; and (3) a methodology to weight the number of high-cost and low-cost hours. Each criterion is described below.

1) **Timeframe for Analysis Period:** In this application, PG&E analyzed how the various candidate TOU periods performed over the period from January 1, 2020 through December 31, 2020. PG&E used its 2020 Adjusted Net Load forecast model to produce hourly MGCs, as 2020 is in the middle of the 5-year period that starts in 2017 and is characterized by steadily increasing loads of RPS generation.

2) **Number of High-Cost Hours:** The number of high-cost hours determines how many hours the model will consider to be "high cost" when evaluating the months for summer season, and determining the hourly periods with most of the high cost hours. For example, if 250 hours are used, the model will classify the hours with the highest to the 250th highest costs as "high cost" hours, and hours ranked 251st and lower as "low-cost" hours.

    In this application, PG&E examined three different scenarios of high cost hours: the Top 100 and the Top 250 hours scenarios, and the Top 5 percent scenario. The use of the top 100 highest-cost hours has been common in CPUC rate design proceedings, and thus is appropriate to examine here. However, more recently, the 250 highest-cost hours scenario was used by the CPUC's consultant, E3, in the Avoided Cost Model it used to allocate capacity costs in R.07-01-041 (filed January 25, 2007).[6] Therefore, PG&E used both Top 100 and Top 250 hours scenarios to perform its analysis here to identify summer season months as well as to make an initial determination of the peak-period hours, to determine whether the choice of 100 or 250 top hours would make a substantial difference in the resulting choice of TOU period definition. PG&E found that both the Top 100 and Top 250 hours' scenarios supported a June-September summer and a 5 p.m. – 10 p.m. peak period. PG&E used the Top 5 percent scenario to refine the determination of TOU periods, including whether or not to include weekends and holidays in the peak.

3) **Equal Weighted Counting Methodology:** PG&E used a simple counting without any weights (in other words, equal weighted counting) for the number of high cost hours used to establish winter and summer months,

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6 The documentation for the 250 hour assumption is on the following webpage of E3: https://ethree.com/public_projects/cpucdr.php.

and TOU periods. This is appropriate because electricity pricing (i.e., rate) for all hours within a specific TOU period (peak, partial-peak or off-peak) are the same by design. The simple counting without weight approach treats the highest and the lowest-cost hours within a TOU period, either peak or off-peak equally, which is consistent with the TOU pricing structure.

F. Determination of Summer and Winter Months

PG&E's current summer season for most of its rates is from May through October.[7] For PG&E, the summer season has higher costs and, therefore, should have higher prices in comparison to the winter months. To determine whether the existing summer months should be adjusted, PG&E reviewed how the highest generation cost hours, under both a Top 100 and a Top 250 scenario, were distributed across the year. Equal weighting was applied to each high-cost hour. The results show that the June through September period captures almost all of the high-cost hours and thus more accurately reflects the months that should be covered by summer season rates.

Table 12-2 shows the percentage of the highest marginal generation cost hours by month under Top 100 hours and Top 250 hours scenarios. Under the Top 100 hours scenario, almost all (99 percent) of the highest cost hours occur during the months of June through September. Under the Top 250 hours scenario, 75 percent of the top cost hours occur in June through September. July and August alone capture 63 percent of the 250 highest-cost hours, and 93 percent of the 100 highest-cost hours.[8]

The period from June through September adequately captures the highest cost hours for both Top 100 and Top 250 hours scenarios. Clearly, the prior inclusion of May and October is no longer appropriate as these two months either have zero or at most less than 1 percent of the highest cost hours, under either the Top 100 or the Top 250 scenario. Accordingly, PG&E proposes that CPUC adopt a four-month summer season from June through September for

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7 In PG&E's 2015 RDW proceeding (D.15-11-013), the CPUC adopted a June-September summer season for PG&E's opt-in residential TOU rates that were the sole rates at issue in that proceeding.

8 PG&E did not consider any higher number of top cost hours than 250. PG&E's Peak Capacity Allocation Factor (PCAF) methodology, used in marginal cost allocation, usually identifies the hours that have at least 80 percent of maximum demand. The number of these hours is almost always less than 250.

use in all of PG&E's rates. The remainder of the year (October-May) should be designated as the winter season.

TABLE 12-2
DISTRIBUTION OF TOP GENERATION MARGINAL COST HOURS ACROSS CALENDAR MONTHS

Percent Count of Highest Cost Hours (Energy + Capacity)			
	Month	Top 250	Top 100
1	January	1%	0%
2	February	0%	0%
3	March	0%	0%
4	April	0%	0%
5	May	0%	0%
6	June	2%	1%
7	July	39%	65%
8	August	24%	28%
9	September	10%	5%
10	October	6%	0%
11	November	8%	0%
12	December	10%	1%

G. Determination of Peak Hours of Day

To determine peak hours, PG&E reviewed how the highest generation hours are distributed across a 24-hour period over the course of the MGC model's forecast year of 2020, which consists of 8,784 hours.[9] Equal-weighted counting was also applied to each high-cost hour that fell under both a Top 100 hour scenario and a Top 250 hour scenario. Table 12-3 shows the percent count of the highest MGC hours by hour of day.

The resulting high-cost hours under the Top 100 and Top 250 hours scenario are closely aligned. Table 12-3 below shows that under the Top 100 hours, 57 percent of the 100 highest cost hours fall in the 6 to 8 p.m. period. Similarly, 55 percent of the top-cost hours in the Top 250 hours scenario occur during those same two hours. Approximately 91 percent of the Top

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9 While a typical year includes 8,760 hours, 2020 includes a leap day in February, for a total of 8,784 hours.

100 high-cost hours, and approximately 95 percent of the Top 250 high-cost hours occur during the five-hour period from 5 p.m. – 10 p.m.[10]

TABLE 12-3
DISTRIBUTION OF TOP COST HOURS ACROSS HOURS OF DAY

Percent Count of Highest Cost Hours (Energy + Capacity)			
	Hour of Day	Top 250	Top 100
1	12 AM to 12 PM	0%	0%
2	12 PM to 1 PM	0%	0%
3	1 PM to 2 PM	0%	0%
4	2 PM to 3 PM	0%	0%
5	3 PM to 4 PM	0%	0%
6	4 PM to 5 PM	2%	2%
7	5 PM to 6 PM	17%	7%
8	6 PM to 7 PM	31%	30%
9	7 PM to 8 PM	24%	27%
10	8 PM to 9 PM	16%	15%
11	9 PM to 10 PM	6%	12%
12	10 PM to 11 PM	3%	7%
13	11 PM to 12 AM	0%	0%

H. Analysis of Summer TOU Periods

Based on the analysis described in the previous section, PG&E made an initial determination targeting the peak period hours to be the period from 5 p.m. – 10 p.m. In developing the final recommendation for the new TOU periods, PG&E analyzed a number of candidate summer peak periods to see which set of hours best captured high-cost hours while minimizing the percentage of low-cost hours. Included among these are the nine scenarios as shown in Table 12-4, for which the peak period occurs all days of week.

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10 PG&E considered a 4 p.m. – 9 p.m. peak, but found 4 p.m. – 5 p.m. period to have only 2 percent of the highest cost hours, whereas the 9 p.m. – 10 p.m. period has about 15 percent of the highest cost hours, a significant difference in the Top 100 hours scenario. Thus, PG&E concluded that the 9 p.m. – 10 p.m. period, not 4 p.m. – 5 p.m., should be included in the new non-residential peak period, to best match the high cost hours of the day under the most current data.

The peak periods start at 3 p.m., 4 p.m. and 5 p.m., with varying duration of peak periods, ending at 9 p.m., 10 p.m. and 11 p.m.[11]

TABLE 12-4
PERCENT OF TARGET COST HOURS AND FALSE POSITIVE RATES OF THE SUMMER TOU PERIODS

Scenario ID	Description	Summer Peak	
		Percent High Cost Hours A = TP/(TP + FN)	False Positive Rate B = FP/(FP + TN)
S-7	Summer Peak: From 3PM to 9PM, All days of the week Summer Partpeak(1): From 1PM to 3PM, All days of the week Summer Partpeak(2): From 9PM to 12AM, All days of the week	86%	22%
S-8	Summer Peak: From 3PM to 10PM, All days of the week Summer Partpeak(1): From 1PM to 3PM, All days of the week Summer Partpeak(2): From 10PM to 12AM, All days of the week	95%	26%
S-9	Summer Peak: From 3PM to 11PM, All days of the week Summer Partpeak(1): From 1PM to 3PM, All days of the week Summer Partpeak(2): From 11PM to 12AM, All days of the week	100%	30%
S-16	Summer Peak: From 4PM to 9PM, All days of the week Summer Partpeak(1): From 2PM to 4PM, All days of the week Summer Partpeak(2): From 9PM to 12AM, All days of the week	86%	17%
S-17	Summer Peak: From 4PM to 10PM, All days of the week Summer Partpeak(1): From 2PM to 4PM, All days of the week Summer Partpeak(2): From 10PM to 12AM, All days of the week	95%	21%
S-18	Summer Peak: From 4PM to 11PM, All days of the week Summer Partpeak(1): From 2PM to 4PM, All days of the week Summer Partpeak(2): From 11PM to 12AM, All days of the week	100%	25%
S-25	Summer Peak: From 5PM to 9PM, All days of the week Summer Partpeak(1): From 3PM to 5PM, All days of the week Summer Partpeak(2): From 9PM to 12AM, All days of the week	84%	13%
S-26	Summer Peak: From 5PM to 10PM, All days of the week Summer Partpeak(1): From 3PM to 5PM, All days of the week Summer Partpeak(2): From 10PM to 12AM, All days of the week	93%	17%
S-27	Summer Peak: From 5PM to 11PM, All days of the week Summer Partpeak(1): From 3PM to 5PM, All days of the week Summer Partpeak(2): From 11PM to 12AM, All days of the week	98%	21%

These scenarios are based on the peak periods occurring during all days of week. The complete set of scenarios analyzed by PG&E includes also the cases with peak periods occurring during Monday through Friday, and Monday

11 PG&E also designed the corresponding part-peak periods, as discussed in Section I of this chapter, below.

through Saturday. The results of all the scenarios are available in the workpapers associated with this chapter. Additionally, the reasoning behind PG&E's proposal that the peak period occur on all days of week (and not just for Monday through Friday) is discussed in Section K of this chapter.

PG&E optimized TOU period scenario analysis by using two metrics: (a) the Percent of High Cost Hours (for determining the peak period, and, for the partial-peak period, the Percent M medium Cost Hours); and (b) the False Positive Rate. PG&E uses these two metrics, combined, to select the scenario that maximizes the percent of high-cost hours, while minimizing the false positive rate hours (shown in the green shaded row in Table 12-4, above).

1. Percent High Cost Target Hours Metric

The Percent High Cost Hours metric quantifies the percentage of the highest cost hours (for this part of the analysis, the 95th percentile costs and beyond) that are captured by a particular candidate peak period definition. Conceptually, these are the hours that "should" be included in the peak period because they are the ones with the highest costs. Generally, the larger is the Percent High Cost Hours metric, the better the peak period definition is at capturing those very high cost hours. The Percent High Cost Hours is calculated as follows:

$$Percent\ High\ Cost\ Hours = \frac{TP}{TP + FN}$$

Where TP = Number of high cost hours falling within the candidate peak period, and FN = Number of high cost hours falling in the part-peak and off-peak periods.

2. False Positive Rate Metric

The False Positive Rate metric quantifies the degree to which low-cost hours (i.e., the hours that are not the highest cost hours), are captured in a candidate peak period. Conceptually, these hours "should not" be included in the peak period because they are not the highest cost ones. The False Positive Rate is defined as follows, and can also be thought of as the percentage of low-cost hours that fall in the peak period:

$$False\ Positive\ Rate = \frac{FP}{FP + TN}$$

Where FP = Number of low-cost hours falling within the peak period, and TN = Number of low-cost hours falling in the part-peak and off-peak periods.

Including the low-cost hours in a peak period is not desirable, but is unavoidable because the peak period needs to be defined to include a block of consecutive hours in a block of consecutive days, while actual high-cost hours can be distributed across hours that are not consecutive. Generally, the lower the False Positive Rate, the better the candidate peak period is (because it means that a higher percentage of low-cost hours have been excluded from the peak period).

3. Analysis

Based on these two metrics, PG&E proposes the hours set forth in Scenario S-26 (shown as the green shaded row in Table 12-4, above) as the summer TOU periods which provide the best balance, with one of the highest Percent High Cost Hours results combined with one of the lowest False Positive Rates of any peak period. S-26 provides a five-hour peak period from 5 p.m. – 10 p.m. during all days of the week, with partial-peak periods occurring for the two hours just before start of the summer peak period (3 p.m. – 5 p.m.), and the two hours just after the peak period ends (10 p.m. – midnight). Increasing the duration of the peak period to more than five hours causes the False Positive Rate to increase significantly, although the Percent High Cost hours improve. Hence, PG&E did not select any of those scenarios. Decreasing the duration of the peak period to less than five hours causes the Percent High Cost hours to drop significantly, although the False Positive Rates improve. Hence, PG&E did not select those scenarios, either.

I. Determination of Summer Partial-Peak Period Hours

PG&E turned to distribution peak hours data as an additional source for the partial-peak period analysis, since the distribution peak hours align well with the generation peak hours with the exception that distribution peak hours occur over a larger number of hours, starting a bit earlier in the day in comparison to the generation peak hours. PG&E analyzed the hourly gross load data in its 19 divisions to determine the partial-peak period that appropriately captures high Marginal Distribution Cost hours. To help design its partial-peak periods, PG&E prepared a Distribution demand (i.e., Peak Capacity Allocation Factor or PCAF) profile for all 19 of its divisions, as well as a load weighted average for its territory. Table 12-5 shows that the percent of PCAFs in each of the 19 divisions in PG&E's service territory for the summer months (June through September) covers approximately 89 percent of the annual PCAF, leaving 11 percent for the rest of the months (winter). PG&E used 2014 historical hourly data, without taking into account possible shift of peak in the future due to additional solar rooftop installations.[12]

The data in Table 12-5 reveals that PG&E's Distribution peaks generally occur during similar hours to the peak of CAISO Gross Load shown in Figure 2-7 of this exhibit. A partial peak of about two to three hours before the peak period (i.e., either 3 p.m. – 5 p.m., or 2 p.m. – 5 p.m.) should provide appropriate distribution price signal. Because the continued addition of solar generation is expected to cause a future shift of the Distribution peak to later hours, PG&E has chosen to propose a two hour partial-peak (instead of three hour) from 3 p.m. – 5 p.m. in this proceeding. In addition, PG&E proposes 10 p.m. to midnight as partial-peak hours, due to relatively high MGC during these hours, as shown in Table 12-3.

TABLE 12-5
SUMMER (JUNE-SEPTEMBER) PCAF DISTRIBUTION FOR PG&E'S 19 DIVISIONS

Hour Ending at Summer	CENTRAL_COAST	DE_ANZA	DIABLO	EAST_BAY	FRESNO	HUMBOLDT	KERN	LOS_PADRES	MISSION	NORTH_BAY	NORTH_VALLEY	PENINSULA	SACRAMENTO	SAN_FRANCISCO	SAN_JOSE	SIERRA	SONOMA	STOCKTON	YOSEMITE	Weighted All
1:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10:00:00 AM	1%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%
11:00:00 AM	4%	0%	0%	4%	0%	0%	0%	1%	0%	0%	0%	2%	0%	5%	0%	0%	0%	0%	0%	1%
12:00:00 PM	6%	1%	0%	6%	0%	1%	1%	3%	1%	0%	0%	7%	0%	9%	0%	0%	0%	0%	0%	1%
1:00:00 PM	7%	2%	0%	7%	0%	2%	2%	4%	2%	1%	0%	8%	0%	10%	1%	0%	2%	0%	0%	2%
2:00:00 PM	8%	5%	0%	8%	2%	3%	4%	6%	6%	3%	1%	10%	1%	10%	4%	0%	5%	2%	3%	3%
3:00:00 PM	8%	9%	3%	8%	6%	5%	7%	9%	10%	6%	2%	10%	4%	10%	9%	2%	9%	4%	6%	6%
4:00:00 PM	8%	12%	8%	7%	11%	6%	11%	10%	13%	9%	6%	9%	8%	9%	13%	8%	13%	8%	9%	10%
5:00:00 PM	8%	15%	17%	4%	17%	8%	14%	10%	14%	14%	11%	9%	14%	7%	16%	15%	16%	14%	14%	14%
6:00:00 PM	7%	15%	24%	2%	18%	9%	15%	8%	13%	18%	18%	8%	19%	3%	16%	21%	15%	20%	18%	16%
7:00:00 PM	7%	9%	24%	1%	18%	11%	16%	7%	10%	16%	23%	3%	21%	0%	12%	24%	11%	21%	19%	16%
8:00:00 PM	8%	4%	18%	2%	14%	13%	14%	7%	7%	10%	22%	2%	19%	0%	7%	19%	8%	16%	15%	12%
9:00:00 PM	8%	2%	7%	4%	9%	13%	10%	7%	5%	5%	13%	2%	11%	0%	3%	8%	4%	9%	10%	7%
10:00:00 PM	5%	1%	0%	3%	4%	8%	5%	4%	3%	2%	4%	0%	4%	0%	1%	1%	2%	4%	5%	3%
11:00:00 PM	0%	0%	0%	0%	1%	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	1%	0%
12:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

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12 Doing this analysis would require significant additional time, which was not possible to complete by June 30, 2016 filing date.

J. Analysis of Winter Peak Periods

PG&E's analysis of the winter TOU periods is similar to that done for the summer season, with the difference being that, for winter, only Peak and Off-Peak periods have been considered, since the range of the Marginal Generation Cost for winter is significantly narrower than for summer. Table 12-6, below, summarizes the results for the scenarios with Peak period occurring all days of week. The scenarios with peak periods occurring during the Monday through Friday and Monday through Saturday are included in the work papers associated with this chapter.

Based on the results shown in Table 12-6, PG&E's peak period proposal for the winter season is Scenario W-31, with a peak period from 5 p.m. – 10 p.m. during all days of week. PG&E is proposing this scenario because it provides an appropriate balance, having a relatively high Percentage of High Cost Hours, and a relatively low False Positive Rate. Scenario W-31 also keeps the peak hours consistent with the recommended 5 p.m. – 10 p.m. summer peak period,[13] and thus will be easier for customers to remember year-round. Similar to the scenarios for summer, the winter scenario analysis shows that increasing the duration of the peak period to more than five hours would cause the False Positive Rate to increase significantly, although the Percent High Cost hours improve. Hence, PG&E did not select those scenarios. Also, decreasing the duration of the peak period to fewer than five hours would cause the Percent High Cost hours to drop significantly, although the False Positive Rates would improve. Hence, PG&E did not select those scenarios, either.

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13 PG&E notes that Scenario W-30, with a four-hour peak from 5 p.m. – 9 p.m. has the same 98 percent of High Cost Hours as does Scenario W-31, but has only 10 percent of the low cost hours, slightly less than the 14 percent for Scenario W-31. Even though Scenarios W-30 shows slightly better low-cost fit, PG&E believe that is far outweighed by the consideration of customer understandability and simplicity. Therefore, PG&E has selected Scenario W-31, which is very close to W-30 but has the important advantage of consistency with the summer peak hours to prevent customer confusion.

TABLE 12-6
PERCENT OF TARGET COST HOURS AND FALSE POSITIVE RATES OF THE WINTER TOU PERIODS

Scenario ID	Description	Winter Peak	
		Percent High Cost Hours A = TP/(TP + FN)	Percent Low Cost Hours B = FP/(FP + TN)
W-25	Winter Peak: From 4PM to 8PM, All days of the week	90%	10%
W-26	Winter Peak: From 4PM to 9PM, All days of the week	100%	14%
W-27	Winter Peak: From 4PM to 10PM, All days of the week	100%	19%
W-28	Winter Peak: From 4PM to 11PM, All days of the week	100%	23%
W-29	Winter Peak: From 5PM to 8PM, All days of the week	88%	6%
W-30	Winter Peak: From 5PM to 9PM, All days of the week	98%	10%
W-31	Winter Peak: From 5PM to 10PM, All days of the week	98%	14%
W-32	Winter Peak: From 5PM to 11PM, All days of the week	98%	19%
W-33	Winter Peak: From 6PM to 8PM, All days of the week	59%	4%
W-34	Winter Peak: From 6PM to 9PM, All days of the week	68%	8%
W-35	Winter Peak: From 6PM to 10PM, All days of the week	68%	12%
W-36	Winter Peak: From 6PM to 11PM, All days of the week	68%	17%

K. Weekdays and Weekends Generation Marginal Costs

PG&E also analyzed the distribution of the highest cost hours across weekdays and weekends. As shown in Table 12-7A for summer and Table 12-6B for winter, a significantly higher proportion of the highest cost hours are seen to occur in the Scenario S-26 and W-31, which refer to the peak periods occurring all days of week, in comparison to the Scenarios S-20 and W-7, which show the weekdays only peak period cases.

TABLE 12-7A
SUMMER PERCENT OF THE HIGHEST COST HOURS OCCURRING IN ALL DAYS AND WEEKDAYS ONLY

Scenario ID	Scenario Description	Summer Peak	
		Percent High Cost Hours A = TP/(TP + FN)	Percent Medium & Low Cost Hours B = FP/(FP + TN)
S-26	Summer Peak: From 5 PM to 10 PM, All days of the week	93%	17%
S-20	Summer Peak: From 5 PM to 10 PM, Monday through Friday	76%	12%

TABLE 12-7B
WINTER PERCENT OF THE HIGHEST COST HOURS OCCURRING IN ALL DAYS AND WEEKDAYS ONLY

Scenario ID	Scenario Description	Winter Peak	
		Percent High Cost Hours	Percent Low Cost Hours
		A = TP/(TP + FN)	B = FP/(FP + TN)
W-31	Winter Peak: From 5PM to 10PM, All days of the week	98%	14%
W-7	Winter Peak: From 5PM to 10PM, Monday through Friday	76%	9%

L. Analysis of Super Off-Peak Period

Discussions of a spring super-off-peak period have been a centerpiece of the CPUC's TOU Period OIR, which included a recommendation by the CAISO for a low super-off peak rate during certain spring months during which negative pricing occurs due to oversupply of generation when hydro-electric facilities have strong spring runoff, and there is plentiful must-take mid-day solar generation as well. A similar concern was the impetus for two other initiatives. In the Residential Rate Reform OIR, the Energy Division recommended that a spring super-off-peak period be included as part of one of the residential opt-in TOU pilot rates (Pilot Rate 3), being tested by each of the IOUs between June 1 2016 and December 31, 2017. This pilot is part of the ramp-up to default residential TOU, targeted for 2019. Similarly, Commissioner Sandoval initiated an Energy Matinee Pricing Pilot to test super-off peak rates for certain non-residential customers starting in 2017. The concept is that by offering very low prices during spring super-off-peak periods, customers would be incented to increase their electric usage during the times when negative generation prices (due to over-supply) are most likely.

Accordingly, PG&E has included here an analysis of the frequency of occurrences of negative MGC hours in order to determine the appropriate hours during which lower prices can be offered to customers as an incentive to shift their consumption from peak period, thereby achieving overall lower procurement costs. Table 12-8 shows percent of negative price hours across months from January to December, and across hour(s) of day. A high concentration of negative MGC is forecast to occur during the month of March, April and May during the hours from 9 a.m. – 3 p.m. Negative MGCs occur due to low loads and excessive renewable generation during these hours. However, PG&E recommends a shorter super-off-peak period from 10 a.m. – 3 p.m., to allow a slightly better rate incentive. A “Super Off-peak Credit” rider, which will provide customers credit for the usage during the period of 10 a.m. – 3 p.m. in the months of March, April and May is proposed for implementation.

TABLE 12-8
PERCENT OF NEGATIVE MARGINAL GENERATION COST HOURS ACROSS MONTH AND HOUR OF DAY

Percent Negative MGC Hours										
Month	**All Hours**	**Midnight to 8 AM**	**8 AM to 9 AM**	**9 AM to 10 AM**	**10 AM to 2 PM**	**2 PM to 3 PM**	**3 PM to 4 PM**	**4 PM to 5 PM**	**5 PM to 6 PM**	**6 PM to Midnight**
Jan	3%	0.0%	0.0%	0.1%	2.9%	0.0%	0.0%	0.0%	0.0%	0.0%
Feb	4%	0.0%	0.0%	0.4%	3.4%	0.1%	0.0%	0.0%	0.0%	0.0%
Mar	17%	0.0%	0.3%	1.2%	11.2%	2.5%	1.5%	0.3%	0.0%	0.0%
Apr	27%	0.0%	1.0%	3.4%	16.9%	2.9%	2.3%	0.4%	0.0%	0.0%
May	20%	0.4%	1.8%	3.1%	11.7%	1.3%	1.0%	0.3%	0.0%	0.0%
Jun	10%	0.0%	1.0%	1.8%	6.6%	0.3%	0.3%	0.0%	0.0%	0.0%
Jul	1%	0.0%	0.1%	0.4%	0.7%	0.0%	0.0%	0.0%	0.0%	0.0%
Aug	2%	0.0%	0.0%	0.6%	1.5%	0.0%	0.0%	0.0%	0.0%	0.0%
Sep	5%	0.0%	0.1%	0.7%	3.5%	0.4%	0.1%	0.0%	0.0%	0.0%
Oct	5%	0.0%	0.0%	0.6%	3.5%	0.6%	0.1%	0.0%	0.0%	0.0%
Nov	4%	0.0%	0.0%	1.0%	3.1%	0.0%	0.0%	0.0%	0.0%	0.0%
Dec	2%	0.0%	0.0%	0.4%	1.6%	0.0%	0.0%	0.0%	0.0%	0.0%
Total	100%	0.4%	4.4%	13.8%	66.7%	8.2%	5.4%	1.0%	0.0%	0.0%

M. Peak Day Pricing and Smart Rate

PDP’s current event hours are from 2 p.m. – 6 p.m. during Peak Day Pricing (PDP) event days. PG&E proposes to update its PDP event hours concurrent with its implementation of the Commission’s decision here approving PG&E’s updated TOU periods for its non-residential customers. PG&E proposes that the PDP event hours be kept at the current four-hour duration; however, the event hours should be revised to 5 p.m. – 9 p.m. These four hours fall within PG&E’s proposed five-hour summer peak period of 5 p.m. – 10 p.m. PG&E believes it is important to maintain the same four-hour duration for the PDP load reductions on critical peak days to avoid attrition from the program, as customers signed up expecting a four-hour curtailment period, and some customers may not be able to curtail their usage for a full five hours. Further details of the proposed PDP program are included in Chapter 1 of Rate Design exhibit.

The SmartRate™ Program (Schedule E-RSmart, E-SOP) is PG&E’s residential critical peak pricing program. The critical peak pricing event hours for the SmartRate Program are currently from 2 p.m. – 7 p.m., and are in effect for a maximum of 15 days per year for enrolled customers. PG&E recognizes that these hours should be aligned with the new residential TOU periods. However, PG&E proposes that the CPUC defer updating the SmartRate Program event hours until the Commission issues its decision on default TOU implementation for the residential customers for several reasons: (1) residential default TOU hours will not be adopted until a decision in the 2018 RDW proceeding expected in late 2018, for implementation in 2019, which will ensure that the SmartRate hours align with the final default residential TOU periods; (2) significant marketing will be taking place to all residential customers about both default TOU and related optional rates, therefore it will be most efficient to communicate the new SmartRate critical peak pricing event hours at the same time; (3) PG&E is concerned that if SmartRate critical peak pricing event hours were shifted later now for the existing approximately 140,000 customers on SmartRate, it would result in significant attrition in the program; (4) PG&E believes that deploying a latter SmartRate critical peak period at the same time as residential default TOU will result in the best customer experience and the highest retention of SmartRate customers; and (5) the misaligned load impacts of 140,000 SmartRate customers (about 3% of Residential customers) will not be anywhere near as impactful as they would be for the PDP Program which has reached an enrollment level of 214,756 non-residential customers.[14]

N. Conclusion

The TOU periods proposed in this chapter have been proposed after carefully considering how the marginal generation costs at hourly level are expected to evolve in coming years, such that the proposed TOU periods will be valid for at least five years, and will provide appropriate price signals to PG&E's customers, thereby incentivizing them in shifting load to lower cost hours. PG&E requests CPUC's approval for adopting these proposed TOU periods, and the peak hours for the PDP.

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14 Typical non-residential customers are significantly bigger than typical residential customers.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 13

MARGINAL COST LOADERS AND FINANCIAL FACTORS

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MARGINAL COST LOADERS AND FINANCIAL FACTORS

A. Introduction

Pacific Gas and Electric Company (PG&E or the Company) incurs capital investments and expenses to meet customer and demand growth as the number of customers and kilowatt demand grows over time. Growth-related capital investments and operations and maintenance (O&M) expenses are the major components of PG&E's marginal costs. PG&E also incurs secondary expenses that are driven by capital investments and O&M expenses. This chapter discusses the loading factors and financial factors that are used to include expenses and financial costs in PG&E's marginal cost calculations.

PG&E requests that the California Public Utilities Commission (CPUC or Commission) find reasonable PG&E's proposed financial factors and loading factors, and the methodologies for calculating them. These must be included in PG&E's marginal cost calculations in order to obtain an accurate determination of marginal cost. The results from PG&E's financial factors model and loaders model are summarized in Table 13-1 and Table 13-2, respectively, at the end of this Chapter.

The remainder of this chapter is organized as follows:

- Section B – Methods
- Section C – Results
- Section D – Conclusion

B. Methods

Marginal transmission, distribution and customer access costs have two components: capital and expense.

Calculation of the capital portions of the marginal costs requires use of financial factors. The financial factors used by PG&E in its marginal costs calculations are: (1) Present Value of Revenue Requirement (PVRR) factors; and (2) Real Economic Carrying Charge (RECC) financial factors. For each dollar of incremental capital in transmission and distribution capacity or customer connection equipment,[1] PG&E incurs incremental O&M expense and administrative and general (A&G) expense. These incremental O&M and A&G expenses in turn require incremental general plant, materials and supplies (M&S), and Cash Working Capital (CWC).

Incremental O&M and A&G expenses, as well as the other incremental expenses to support the O&M and A&G, are captured in the marginal cost loading factors. A final factor, a Franchise Fees and Uncollectibles (FF&U) loading factor, is taken directly from PG&E's 2017 GRC Phase I Application (A.15-09-001) and is applied to all incremental expense loadings.

The methodologies for each of the financial factors and loading factors proposed by PG&E for use in this proceeding are described below.

1. Financial Factors

a. Real Economic Carrying Charge

The RECC factor represents a first-year levelized revenue requirement in constant dollars over the service life of an investment adjusted for inflation and discounted at PG&E's current after-tax weighted average cost of capital. Multiplying a marginal capital investment by an RECC factor results in the first-year revenue requirement for that investment. Using PG&E's financial factors model, PG&E calculates RECC factors for a variety of specific capital asset classes. Additionally, results for selected asset classes are weighted to develop composite RECC factors for major asset categories, such as electric distribution, common plant, and general plant. These RECC factors are used in PG&E's Marginal Transmission Capacity Cost (MTCC) calculations, Marginal Distribution Capacity Cost (MDCC) calculations, and in the Rental Method-based calculations for the marginal connection equipment cost component of Marginal Customer Access Costs (MCAC).

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1 In contrast to growth in demand for transmission, distribution and customer access, which require PG&E-owned capital investments, generation demand growth is assumed to be met from an external marketplace. Thus, it is assumed that PG&E will not incur marginal A&G costs or other loaders for generation, beyond levels included in the market price of generation capacity and energy.

The results of PG&E’s RECC calculations are summarized in Table 13-1.

b. Present Value of Revenue Requirement Factor

The PVRR factor, when applied to a capital investment, yields a value that represents the present value of annual revenue requirements for the capital-related charges (depreciation expense less net salvage cost), income taxes, and property insurance discounted at PG&E’s current cost of capital to earn the rate of return over the service life of a plant addition. PG&E calculates PVRR factors for the same asset classes and weighted composites of major asset classes as calculated for RECC factors. Using PG&E’s financial factors model, PVRR factors are calculated as the present value of revenue requirement for an assumed level of up front capital investment for each asset class that is divided by that up front capital investment amount, resulting in unitless PVRR factors. These PVRR factors are used in PG&E’s New Customer Only (NCO) method-based calculations for the marginal connection equipment cost component of MCAC.

The results of PG&E’s PVRR factor calculations are summarized in Table 13-1.

c. Financial Factors Model Redesign

For PG&E’s 2017 GRC Phase II, PG&E has revised and redesigned its financial factors model to improve its transparency, accuracy, and ease of use. The prior model was complex and relied upon Visual Basic for Applications (VBA) programming code to perform calculations for each asset class. The redesigned model no longer uses VBA, and lays out calculations to be easier to follow linearly. Additionally, a half-year convention is now applied consistently throughout the model, improving accuracy. This redesign significantly improves transparency and model usability.

2. Loading Factors

a. Operations and Maintenance Loading Factor

When PG&E adds to its transmission and distribution facilities to meet forecast increases in demand, PG&E must incur additional O&M

expense to operate and maintain the expanded lines and substation facilities. Likewise, when PG&E connects additional customers, PG&E must incur additional O&M expense to operate and maintain the customer connection equipment (final line transformers, secondary conductors, services, and meters). Accordingly, PG&E calculates O&M loading factors for MTCC and MDCC calculations, and for the connection equipment component in the MCAC calculations. Annual O&M expenses were estimated by relating average annual O&M from 2012 to 2014 to average annual plant balances for 2012 to 2014.

For marginal costs, PG&E calculates O&M loading factors separately for different types of assets and differentiates O&M between overhead and underground capital equipment where appropriate. Expenses that are: (1) not related to transmission equipment, distribution equipment, services, and meters; (2) not marginal; or (3) directly paid by customers are removed from these calculations. For example, vegetation management (i.e., tree-trimming) expenses that are not related to service conductors are removed from the overhead line maintenance expenses. The data for these calculations are from PG&E's FERC Form 1 filings for 2012-2014 and from PG&E's 2017 GRC Phase I (A.15-09-001).

PG&E's proposed loading factors for all distribution and transmission O&M categories are summarized in Table 13-2.

b. Administrative and General Expenses Loading Factor

The A&G loading factor reflects the increase in labor-related A&G expenses and payroll taxes associated with increased O&M expenses. This loading factor accounts for the costs of payroll taxes, pensions and benefits, workers compensation, and liability insurance. Specifically, the A&G loading factor is the ratio of 2017 Test Year marginal A&G expenses and payroll taxes from PG&E's 2017 GRC Phase I to 2017 Test Year total O&M expenses (including plant, customer services, and customer accounts O&M) from PG&E's 2017 GRC, Phase I. PG&E proposes an A&G loading factor equal to 26.17 percent for distribution and 18.93 percent for transmission, as shown in Table 13-2, below.

c. General Plant Loading Factor

The General Plant[2] Loading Factor (GPLF) accounts for the additional common and general plant required to support incremental O&M and marginal A&G expense. Common and general plant includes such items as structures and improvements, office furniture and equipment, computers and software, vehicles, telecommunications equipment and data systems, and other equipment.

The GPLF reflects the ratio of the incremental annual carrying costs for general and common plant in service assigned to distribution O&M expenses and marginal A&G expenses. RECC factors, as discussed above, for common and general plant asset categories are applied to the respective plant in service balances to derive weighted total annualized cost of common and general plant. PG&E proposes a GPLF loader equal to 3.92 percent for distribution and 8.49 percent for transmission, as shown in Table 13-2.

d. Materials and Supplies Loading Factor

The M&S loading factor accounts for the cost to keep materials and supplies in stock for use in daily field operations as well as prepayments for insurance.[3] Materials and supplies as well as prepayments are included in this calculation as they both relate to O&M and marginal A&G expenses. Prepayments are removed from working cash to develop the CWC loading factor, discussed below, to prevent double counting because prepayments are included here.

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[2] In accordance with past marginal cost practice, and for simplicity, the term "General Plant" is used here to refer to both common plant and general plant. Common plant describes plant that is used for both gas and electric service, such as communications equipment, buildings, vehicles, etc.

General Plant can be specific for one service such as gas or electric. However, it cannot be (or is not) specific to the various functions within a service (e.g., distribution, transmission, or generation). For example, some equipment may be identified as used for electric service, but not identified with a particular function. Because it was not identified as associated with a particular function, that equipment was assigned to electric general plant.

[3] In accordance with past marginal cost practice, and for simplicity, the term "Materials and Supplies" is used here to refer to materials and supplies, cash working capital and prepayments for insurance.

This M&S loading factor is the ratio of M&S and prepayments expenses to distribution O&M and marginal A&G expenses that is annualized to a levelized revenue requirement. This approach, first proposed in PG&E's 2014 GRC Phase II, is a refinement of PG&E's prior methodology by calculating the loading factor on the basis of distribution O&M and marginal A&G expenses rather than total rate base less working capital. This refinement results in a loading factor that is calculated on a basis that is consistent with the amounts to which it is applied. PG&E calculated the M&S loading factor using data obtained from PG&E's 2017 GRC Phase I testimony and workpapers. PG&E proposes an M&S loading factor of 0.75 percent, as shown in Table 13-2, below.

e. Cash Working Capital Loading Factor

The CWC loading factor accounts for the requirement that PG&E must keep funds available to meet the costs of daily operations. These funds, referred to as cash working capital, provide funds required for day-to-day operations as well as funds used to pay operating expenses in advance of receiving customer payments.

The CWC loading factor reflects the ratio of working cash related to electric distribution (with prepayments for insurance removed) to electric distribution O&M and marginal A&G expenses that is then annualized to a levelized annual revenue requirement for these costs. This approach, first proposed in PG&E's 2014 GRC Phase II, is a refinement of PG&E's prior methodology by calculating the loading factor on the basis of distribution O&M and marginal A&G expenses rather than total rate base less working capital. This refinement results in a loading factor that is calculated on a basis that is consistent with the amounts to which it is applied. PG&E calculated this CWC loading factor using data obtained from PG&E's 2017 GRC Phase I testimony and workpapers. PG&E proposes an annualized CWC loading factor of 1.38 percent, as shown in Table 13-2, below.

f. Franchise Fee and Uncollectibles Loading Factor

PG&E must pay franchise fees to cities and counties for the right to install and maintain equipment on public streets, roads, and rights-of-ways. PG&E also incurs uncollectible expenses due to some customers defaulting on their credit (i.e., not paying for energy they received). Both of these expenses are related to the total expenses estimated to be incurred by the Company and are recovered from customers through rates.

PG&E proposed an FF&U factor in the Company's 2017 GRC Phase I Application (A.15-09-001), applicable to all revenue requirement expenses. In that Application, PG&E calculated an FF&U factor of 1.0113. This factor is applied to marginal distribution expenses related to investment in distribution plant for the MDCC calculations and to expenses related to the investment in connection equipment and to ongoing customer access expenses in the MCAC calculations.

g. Loaders Model Changes

Previously, O&M loading factors using multiple years of historical data were calculated by dividing 3-year average expense, in constant dollars, by 3-year average plant, also in constant dollars. The resulting ratio is the loading factor. However, averaging multiple years of plant and expense data required the use of escalation indices to convert the data to constant dollars. The model has been updated to calculate the loading factors for each year of data and then average the unitless ratios to determine the final loading factor. This update eliminates the need for escalation factors and results in simpler, more transparent loading factor calculations.

C. Results

The results from PG&E's financial factors model and loaders model are summarized in Table 13-1 and Table 13-2 below:

TABLE 13-1
SUMMARY OF RESULTS OF FINANCIAL FACTORS MODEL

Line No.	Category	PVRR	RECC
1	Transformers Composite	1.4466	7.62%
2	Services Composite	1.4425	6.44%
3	Meters	1.4366	9.84%
4	Primary Composite	1.4577	6.47%
5	Secondary Composite	1.4596	6.65%
6	Customer Composite	1.4432	7.45%
8	Common Plant Composite	1.2500	11.71%
9	Electric General Plant Composite	1.2366	7.68%
10	Electric Transmission Composite	1.4400	6.94%

TABLE 13-2
SUMMARY OF LOADERS BY CATEGORY

Line No.	Loader	Category	Value
1	Distribution O&M	Substation Plant	2.52%
2	Distribution O&M	Meter Plant	1.65%
3	Distribution O&M	Overhead Primary Line Plant	7.48%
4	Distribution O&M	Overhead Secondary Line Plant	2.28%
5	Distribution O&M	Underground Primary Line Plant	1.31%
6	Distribution O&M	Underground Secondary Line Plant	1.31%
7	Distribution O&M	Service Drop Plant	0.37%
8	Distribution O&M	Overhead Service Drop Plant	0.25%
9	Distribution O&M	Underground Service Drop Plant	0.76%
10	Distribution O&M	Final Line Transformer Plant	0.09%
11	Distribution O&M	Aboveground Final Line Transformers Plant	0.06%
12	Distribution O&M	Underground Final Line Transformers Plant	0.19%
13	Transmission O&M	Transmission Plant	3.04%
14	Transmission A&G	Transmission O&M Expenses	18.93%
15	Transmission GPLF	Transmission O&M + A&G Expenses	8.49 %
16	Distribution A&G	Distribution O&M expenses	26.17%
17	Distribution GPLF	Distribution O&M + A&G expenses	3.92%
18	M&S	Distribution O&M + A&G expenses	0.75%
19	CWC	Distribution O&M + A&G expenses	1.38%
20	FF&U	All Expenses	1.0113

D. Conclusion

Marginal cost loading factors and financial factors must be included in the marginal cost calculations to obtain an accurate determination of marginal cost. PG&E requests that Commission approve the financial factors and loading factors presented above, as well as the methodologies for calculating them, for inclusion in the appropriate marginal costs.